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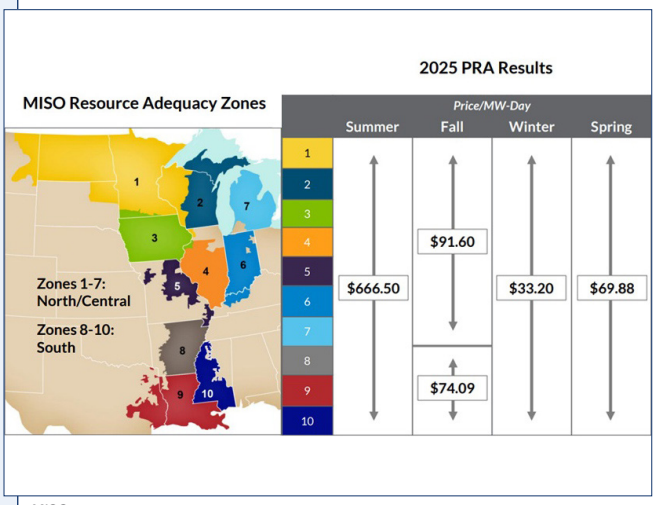
YES ENERGY

2025 YEAR IN REVIEW

Top Stories from RTO Insider, ERO Insider and NetZero Insider

MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction



MISO

A few LSEs in MISO may have sticker shock over summer 2025 capacity auction prices jumping to $666.50/MW-day from $30/MW-day a year ago. MISO said auction pricing bolsters its case that members need to add generation now.

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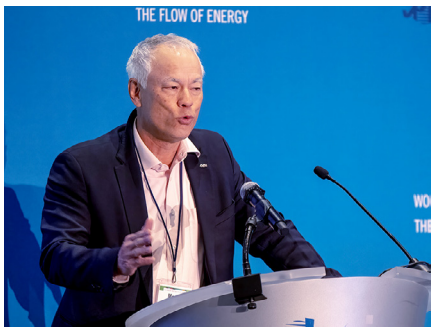
MISO Requires Load Shed in New Orleans to Avoid Grid Instability *(p.16)*

DOE Reliability Report Argues Changes Required to Avoid Outages Past 2030 *(p.27)*



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PJM Stakeholders Vote Out 2 Board Members (p.9)

The additional turnover on PJM's board would come at time when the RTO is facing big challenges — including the need to replace its CEO.

PJM Capacity Prices Hit $329/MW-day Price Cap *(p.6)*

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Vinson & Elkins

Trump Replacing FERC Chair Christie with Laura Swett (p.4)

Why replace fellow Republican Christie? The Trump administration has been skeptical of independent agencies and is openly favorable to pipelines. Much of nominee Laura Swett's legal resume involves defense of pipeline projects.

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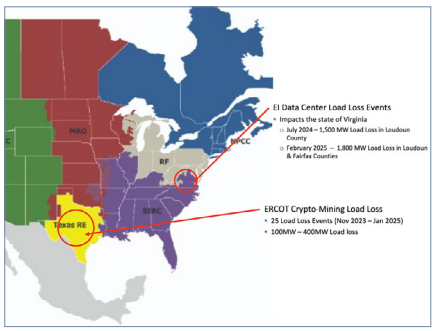

NERC

Data Centers' Reliability Impacts Examined at FERC Meeting (p.24)

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Editor's Note: MISO and PJM Capacity Prices; Data Center Boom; Trump Upheaval

Ken Sands

In 2025, the energy markets saw record capacity auction prices in MISO and PJM, and the ensuing political fallout in PJM leadership. Resource adequacy fears were based on proposals for data centers that might or might not ever get built.

Some big transmission projects advanced, while others floundered. The debate over co-location of load contributed to changes in FERC leadership. And renewable energy took a beating.

To say 2025 was eventful in an understatement.

RTO Insider reporters were inside the meeting rooms from coast to coast to chronicle this industrywide upheaval. Plus we began coverage of Ontario's IESO as it launched its nodal market. Across the news enterprise, our staff produced an average of 160 articles per month throughout the year. But our focus is on quality, not just quantity.

This special 52nd weekly edition of *RTO Insider* brings you the most-read stories of 2025 from our flagship operation, as well as from the ERO and NetZero publications.

This edition provides a comprehensive look at the most compelling stories in a tumultuous year. In reviewing these stories, themes have emerged that likely will continue to dominate policy discussions in 2026.

Who will pay for the generation and transmission needed to support the artificial intelligence data centers? How far will the new FERC commissioners go in asserting authority over data center interconnections? Will renewable energy projects continue to proliferate despite the political headwinds?

These issues and more will be explored in the first *RTO Insider* edition of 2026, in which our reporters and columnists set the scene for what could be another tumultuous year.

Stay tuned.

— Ken Sands

MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction

By Amanda Durish Cook | | Originally Published 4/28/25

MISO's 2025/26 capacity auction returned $666.50/MW-day prices across all zones in the summer, reinforcing the need for members to build new generation fast, the grid operator said.

While none of MISO's resource zones experienced a capacity deficit, MISO said it's inching closer to pervasive shortfalls. The summer's capacity *prices* represent a 22-fold increase over summer capacity prices in 2024.

Beyond summer, MISO zones cleared uniformly at $69.88/MW-day in spring and $33.20/MW-day in winter. For fall, MISO Midwest cleared at $91.60 while MISO South cleared at $74.09/MW-day. MISO said the split in fall pricing occurred due to its transfer limits between its Midwest and South regions.

Annualized, MISO's capacity prices are $217/MW-day for MISO Midwest and $212/MW-day for MISO South.

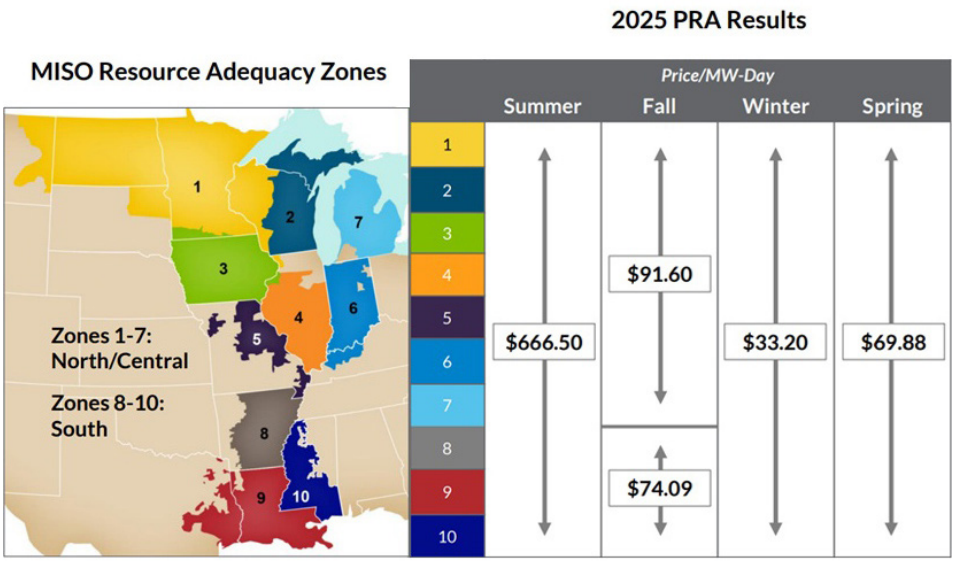
Prices go into effect June 1, when the planning year begins.

In the 2024/25 capacity auction, Missouri's Zone 5 cleared at the $719.81/MW-day cost of new entry for generation in spring and fall. All other MISO zones cleared at $30/MW-day in the summer, $15/MW-day in the fall, $0.75/MW-day in the winter and $34.10/MW-day in the spring. (See *Missouri Zone Comes up Short in MISO's 2nd Seasonal Capacity Auction, Prices Surpass $700/MW-day*.)

The 2025/26 auction was MISO's first to feature sloped demand curves by season. The grid operator hoped the curves would function as a safety net to have more capacity on hand than strictly necessary to meet planning reserve margin requirements. FERC in 2024 allowed MISO to use them in place of the vertical demand curve it had been using since 2011. (See *FERC Approves Sloped Demand Curve in MISO Capacity Market*.)

MISO said the sloped curves placed an expected higher price on capacity, "reflecting the increased value of accredited capacity beyond the seasonal planning reserve margin target." The grid operator said the auction cleared 1.9% above its 7.9% summer planning reserve margin, the highest margin it has. MISO said, effectively, it's heading into summer with a 10.1% summer margin at 101.8 GW in MISO Midwest and an 8.7% margin at 35.7 GW in MISO South.

Ahead of the auction, MISO anticipated a 122.66-GW summer coincident peak and required a 7.9% planning reserve margin at 135.3 GW for the auction.



MISO 2025-26 Planning Resource Auction clearing prices by season and zone | *MISO*

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MISO IMM: Capacity Prices Efficient Despite Yearslong Error

Members Say MISO RA Better off Under Seasonal Capacity Auctions, Sloped Curve

MISO IMM Blasts NERC Long-term Assessment, Says RTO in Good RA Spot

MISO said as with previous auctions, most of its load-serving entities "self-supplied or secured capacity in advance" and thus are shielded from this year's pricing.

The RTO said while its sloped curves cleared extra capacity, it noticed the footprint's spare capacity beyond planning reserve margins dwindled 43% this year compared to summer 2024. MISO said the drop occurred despite a slightly lower planning reserve margin aim than summer 2024's 9% target. The RTO said it oversaw 140.7 GW in summer 2024 offers and 137.8 GW in summer 2025 offers.

The 5.1 GW in new capacity, made up mostly of solar generation, and 1.2 GW in capacity accreditation increases added over the last planning year were no match for 4.9 GW in accreditation decreases, 3.3 GW in retirements and suspensions, and a nearly 1-GW loss in external suppliers, MISO reported.

"New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports. The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions," MISO said in a presentation accompanying auction results.

Over 2024, MISO and the Organization of MISO States through their joint resource adequacy survey showed that anywhere from a 1.1-GW surplus to a 2.7-GW shortfall could be possible by summer 2025. MISO leadership has been cautioning its stakeholders for more than a year that faster generation additions are a must. ■

Trump Replacing FERC Chair Christie with Laura Swett

By James Downing | Originally Published 6/3/25

FERC Chair Mark Christie's tenure running the commission is coming to an end, as President Donald Trump on June 2 nominated Laura Swett of Vinson & Elkins to replace him.

"I learned this evening from a media inquiry that President Trump has appointed Laura Swett to replace me when my term expires," Christie posted on X. "I congratulate Laura and wish her the best. I will remain in office for a few weeks after June 30 to help get key orders out."

Christie's term ends June 30; if confirmed, and depending on when she is sworn in, Swett would be able to serve a full five-year term. Another seat remains open since former Chair Willie Phillips stepped down earlier this year, but that term would only extend into 2026. Any new commissioner in that seat would need to be effectively nominated and confirmed twice to serve longer.

Swett's *nomination* has been referred to the Senate Energy and Natural Resources Committee. She has previous experience at FERC serving on the staff of Chair Kevin McIntyre and former Commissioner Bernard McNamee, both Trump nominees in his first term. She also worked at the Office of Enforcement, according to her LinkedIn page.

Former FERC Chair Neil Chatterjee, who overlapped with both Swett and Christie on the commission, *called* the news bittersweet on X.

"I adore Laura Swett and believe she will be an excellent FERC chair (if given the chance by OIRA and OMB)," Chatterjee said, referencing the White House's Office of Information and Regulatory Affairs and Office of Management and Budget. "But Christie is a patriot; all he did was run the agency well. He's a veteran who has dedicated his life to serving America. He deserved better."

The Trump administration has been skeptical of independent agencies generally, reportedly telling Phillips it would fire him if he did not step down, leading to his resignation. Trump issued an executive order in February trying to bring FERC and other similar agencies more under his control. (See *Trump Claims Authority over Independent Agencies in Executive Order*.)

Laura Swett | *Vinson & Elkins*

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FERC Directs PJM to Issue Rules for Co-locating Generation and Load

Christie Says Farewell to FERC at Final Meeting as Chair

Will the Supreme Court End FERC's Independence?

Christie spent his first press conference as chair addressing that executive order and has repeatedly answered questions on it since. While he put some of it in the context of normal relations between a president and FERC, he also made it clear that he had to follow the laws that govern FERC. (See *FERC's Christie Says Existing Policies Can Align with Trump's Order*.)

One area Christie made clear then that FERC could not tolerate was *ex parte* communications on cases pending before it.

"We do not allow ***ex parte*** communications; that would violate the [Government in the] Sunshine Act," Christie said at the press conference in February. "It would also violate everything I know about due process in contested proceedings going back to being a state regulator. We didn't allow it in Virginia, so we're not going to start allowing ***ex parte*** communications."

Reactions

"I think it's great that Laura has been nominated by the president," McNamee said in an interview. "I think she'll do a fantastic job as a commissioner, and I knew that because she provided great and sound advice to me when she was my attorney adviser, when I was a commissioner."

Swett advised McNamee on pipeline issues when she was his staffer, and much

of her work at Vinson was in that area.

The issue of environmental assessment in pipeline permitting has caused some partisan splits among commissioners in the last decade, especially around how much attention FERC must pay to the downstream greenhouse gas emissions.

Former Chair Richard Glick's efforts to update the pipeline approval process after some losses in the courts wound up sinking his renomination in 2022, but a recent Supreme Court decision means those debates are likely coming to an end regardless of FERC's composition.

In *Seven County Infrastructure Coalition v. Eagle County*, issued May 29, the majority found that the U.S. Surface Transportation Board was right to not consider upstream and downstream effects from approving oil shipments over rail. In a post on X, Christie called the decision "the most important permitting reform in decades."

Trade associations and other groups active before FERC released statements on June 3 congratulating Swett for the nomination.

Americans for a Clean Energy Grid Executive Director Christina Hayes offered congratulations in a statement and argued for continued action on transmission.

"In her previous stints as a senior leader at FERC, she worked on policies that emphasized grid reliability," Hayes said. "At a time when American energy demand is set to skyrocket, no policy area is as essential to our energy dominance as transmission planning reform. ACEG's coalition of transmission policy advocates across the political spectrum looks forward to working with Swett in her new role and urges continued FERC leadership in implementing the bipartisan consensus behind Order No. 1920. America's energy dominance depends on it."

In addition to congratulating Swett, Electricity Customer Alliance Executive Director Jeff Dennis thanked Christie for his service and for keeping reliability at the top of FERC's priorities.

"We look forward to working with her and the rest of the commission to advance customer-centric solutions that support the power system expansion our nation needs to meet the demands of a growing digital economy while keeping energy affordable for all customers," Dennis said. ■

PJM Capacity Prices Hit $329/MW-day Price Cap

By Devin Leith-Yessian and Rich Heidorn Jr. | Originally Published 7/22/25

PJM capacity prices soared to $329.17/MW-day (UCAP) RTO-wide for delivery year 2026/27, hitting the price cap approved by FERC after prices rose nearly 10-fold in the July 2024 auction.

The clearing price is the highest in PJM history and an increase of $59.22 (22%) from last year's record for the RTO.

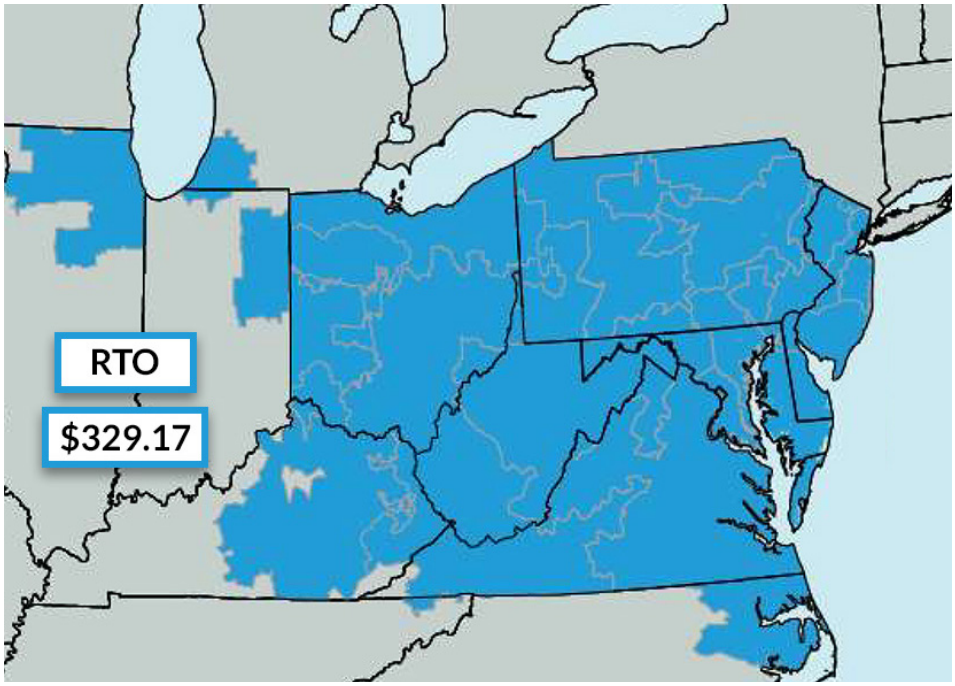
Prices would have hit $388.57/MW-day without the cap, PJM said in its report on the auction. The cleared supply totals $16.1 billion, up 9.5% from the $14.7 billion last year.

"This is a continuation of trends that we've been seeing: a tightening of the supply and demand conditions," Stu Bresler, executive vice president of PJM market services and strategy, said in a press briefing after results were announced July 22.

PJM's forecast peak load for 2026/27 increased by 5,446 MW from last year due to data center expansion, electrification and economic growth. "It's probably a true statement to say that the majority of the demand increase we saw was … those data center additions," Bresler said.

However, prices fell in the Baltimore Gas and Electric (BGE) and Dominion zones, which cleared at $466.35/MW-day and $444.26/MW-day respectively last year. Thus, although the increased capacity costs will boost many retail customers' bills by 1.5 to 5%, Dominion customers could save money, Bresler said.

Supply offered dropped 500.5 MW (UCAP) to 135,191.8 MW. New generation and uprates totaled 2,669 MW, the first increase in the past four auctions. In addition, 17 generating units with 1,100 MW of Capacity Interconnection Rights withdrew their retirements since the 2024 results were announced.



PJM capacity prices cleared at $329.17/MW-day (UCAP) RTO-wide for delivery year 2026/27, hitting the price cap approved by FERC after prices rose nearly 10-fold in the July 2024 auction. | *PJM*

"We were pleased to see the new resources and the uprates that came in," Bresler said. "We're pleased to see the reversals of retirements, because that's the kind of thing we need and the kind of thing that one would expect from the collection of information that's out there, including the results of the last capacity auction." The Base Residual Auction (BRA) procured 134,311 MW of unforced capacity generation (UCAP) and demand response. Regions under the Fixed Resource Requirement acquired an additional 11,933 MW (UCAP) for a total of 146,244 MW (UCAP).

The reserve margin is 18.9%, 309 MW ICAP lower than the target of 19.1%.

Cleared resources were dominated by natural gas (45%), nuclear (21%) and coal (22%), with contributions from hydro (4%), wind (3%) and solar (1%). Declining fleet-wide accreditation values pushed the amount of supply offered down by about 326 MW from the 2025/26 BRA. PJM's auction *report* stated that 3 GW less gas was offered in the 2026/27 auction.

An additional 2 GW of wind generation cleared in the auction, followed by 867 MW of coal and 578 MW of oil. While the amount of DR offered was nearly flat, the resource class saw a significant drop in its effective load-carrying capability (ELCC) rating, causing the amount of UCAP clearing to fall by 224 MW.

Bresler said almost every resource that submitted offers cleared, aside from one that had its minimum offer set above the maximum clearing price. He said the results follow a trend of tightening supply and demand in recent auctions, which PJM has argued could lead to a capacity shortfall in the 2029/30 delivery year.

"I think this auction, just as the last one, served its purpose and very transparently reflected supply and demand," Bresler said.

RMR Impact

Bresler said including generators on reliability-must-run (RMR) agreements as supply helped dampen prices and reduced constraints, allowing BGE and Dominion to clear along with the rest of the RTO.

"I think that there was a significant impact from including the RMRs at zero [dollars] in the supply stack, and … there were

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probably transmission upgrades going into place that changed the transmission import capabilities for those two zones as well," Bresler said. "So, even without the lower cap, we still would not have had price separation in this auction."

In the 2024 auction for 2025/26, the clearing price for most of the RTO jumped to $269.92/MW-day, the result of load growth, generation deactivations and changes to risk modeling that shrank reserve margins. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.) The 2024/25 auction had seen a price of $28.92/MW-day for most of the RTO, with BGE hitting $73/MW-day.

Pa./PJM Settlement Lowered Clearing Prices

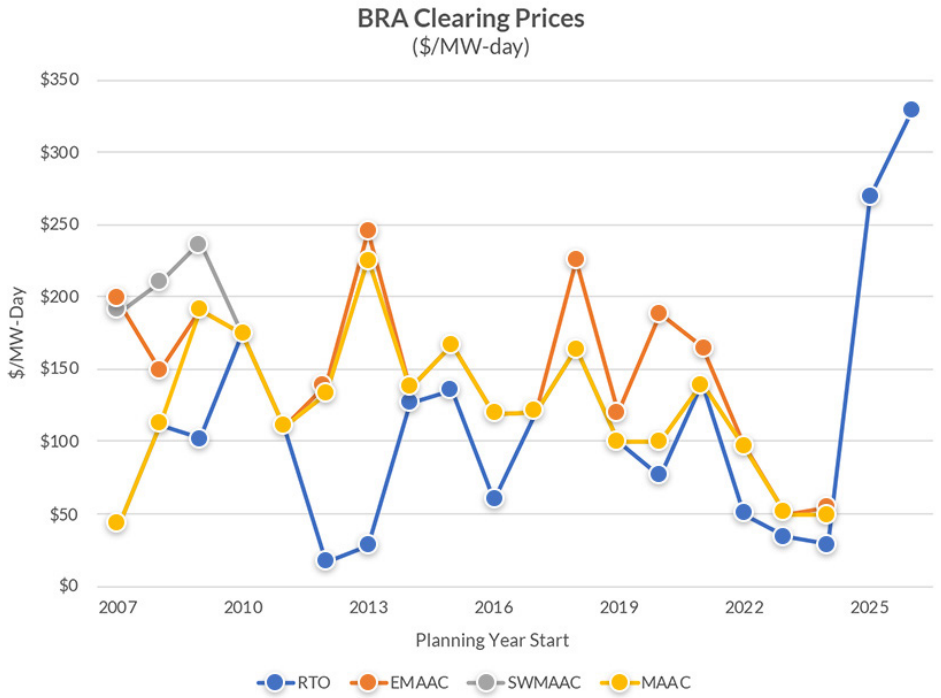
The 2026/27 auction design has been the subject of several rule changes and FERC complaints, including a settlement between PJM and Pennsylvania Gov. Josh Shapiro (D) to lower the maximum clearing price to $325/MW-day and establish a $175/MW-day floor. The settlement is effective for the 2026/27 and 2027/28 auctions (ER25-1357). (See *FERC Approves PJM-Pa. Agreement on Capacity Price Cap, Floor*.)

While the price band initially would be set at $175 to $325/MW-day, those values would be readjusted annually based on the accreditation of the reference resource.

PJM and the governor argued the settlement would stabilize prices while several market changes are implemented. A complaint filed by Shapiro's office said a lower maximum price was needed as the capacity market is unable to send adequate price signals under a compressed auction schedule and while the interconnection queue remains backlogged, preventing developers from bringing new supply in response to high prices (*EL25-46*).

In a *statement* following the posting of the auction results, Shapiro said the settlement avoided "grossly excessive price increases" and saved consumers $8.3 billion.

NRDC Senior Advocate Tom Rutigliano said the settlement prevented windfall payments to generation owners without compromising on reliability. He said the resulting price signals are ample to maintain existing resources and support new development and so long as there are barriers to new entry, such as the backlogged interconnection queue, higher prices would have served no purpose.



Base Residual Auction clearing prices by beginning delivery year for the RTO, EMAAC, SWMAAC and MAAC Locational Delivery Zones. All four LDAs cleared at $329.17 for 2026/27, a $59.25 (22%) increase from $269.92 for 2025/26. | *PJM*

In a statement, Illinois Citizens Utility Board Executive Director Sarah Moskowitz noted the settlement blunted capacity prices but argued the spike in capacity prices remains unacceptable and follows policy shortcomings at PJM.

"The power grid operator's policy decisions too often favor outdated, expensive power plants and needlessly block low-cost clean energy resources and battery projects from connecting to the grid and bringing down prices. This extended price spike was preventable. It ramps up the urgency of implementing long-term reforms at PJM and comprehensive energy legislation in Illinois, such as the Clean and Reliable Grid Affordability Act, to protect customers from price spikes that serve only to give power generators windfall profits," she said.

Auction Design Changes

PJM also received FERC approval to rework several market components, including modeling some resources operating on reliability-must-run agreements as supply in the capacity market (*ER25-682*). One of the factors that drove a spike in capacity prices in the 2025/26 BRA was two generators leaving the supply stack to begin running as RMR resources — the 1,289-MW Brandon Shores coal plant and the 843-MW H.A. Wagner oil-fired plant. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

The filing also established an RTO-wide non-performance charge rate and maintained the reference resource for the 2026/27 auction as a combustion turbine, rather than going through with a scheduled shift to a combined cycle unit.

This is the first auction in which intermittent, storage and hybrid resources holding capacity interconnection rights (CIRs) were required to submit capacity offers. FERC granted PJM's proposal to eliminate an exception from the capacity must-offer requirement for those resource types after the RTO said there was about 1.6 GW of capacity not offered. PJM argued that requiring all resources holding CIRs to submit capacity sell offers will prevent the exercise of market power and more accurately reflect supply and demand (*ER25-785*).

The order eliminating the must-offer exemption also established an alternative market seller offer cap (MSOC) set at a resource's capacity performance quantified risk (CPQR). The filing argued the change would allow intermittent and

storage resources to more accurately reflect the risks they face by taking on a capacity obligation.

Rising capacity clearing prices, and wholesale market costs generally, have been a source of consternation for consumer advocates and political leaders across many PJM states. Both Pennsylvania and New Jersey have raised the specter of leaving the RTO if reliability and cost concerns go unanswered. In July, nine governors signed onto a *letter* requesting that the qualifications for candidates to replace CEO Manu Asthana and to fill two open Board of Managers positions include the ability to restore public confidence and address "difficult decisions that could substantially raise consumer bills."

"In the past, other regions looked to join PJM due to its many strengths; today, across the region, discussions of leaving PJM are becoming increasingly common," the letter said. "These unwelcome developments reflect legitimate concerns about PJM's trajectory. We write, as a bipartisan group of governors elected by the many millions of citizens of our respective states, to tell you that fundamental changes, and new leadership, are needed to restore confidence in PJM's ability to meet the many challenges of this moment."

Rutigliano said prices increased due to the combination of increasing data center demand and risk modeling capturing reliability issues with gas generation. Without the increase in wind generation, he said PJM would not have been able to meet reliability standards, underscoring the need for PJM to continue clearing its interconnection queue and for states and the federal government to address siting and permitting barriers.

"The bright spot in this auction is a 75% increase in wind and solar. That jump will save PJM from an unacceptable risk of blackouts in 2026. PJM will stay reliable in 2026 thanks to the increase in renewable power. However, these low-cost resources still only account for 4% of the PJM's supply, so PJM must continue to significantly speed up approvals of the 85 GW waiting to connect. The only real solution to higher energy prices is to keep adding more renewable energy and storage to the grid," he said in a statement.

Rutigliano told *RTO Insider* that states pushing for winterization of gas plants and PJM easing its restrictions on external resources selling capacity into PJM could buy the RTO at most two years before reliability issues become paramount, but the long-term solution lies in ensuring that renewable penetration accelerates.

Advanced Energy United Policy Director Jon Gordon said the auction results show that new resources are needed to meet forecast demand. However, long interconnection queues prevent developers from bringing new supply to market. He said fast-track study processes, advanced transmission technologies, load flexibility and virtual power plants can facilitate new entry while PJM advances its cluster-based interconnection study process.

"When prices go up, it's meant to send a signal to energy developers: 'We need more supply.' But at the same time, PJM is holding up a big red 'STOP' sign to energy developers," Gordon said. "Many projects have been stuck in the closed queue for over six years, a significant delay that adds additional risk and cost for developers and is likely to contribute to some otherwise viable projects never getting built.

"Given the magnitude of this crisis, PJM, transmission owners, project developers and states need to do everything they can to move projects in the current interconnection process through to completion while finding additional ways to accelerate the interconnection process immediately. The high auction prices underscore the urgency of allowing project developers to begin to propose new projects for the queue that reflect today's economic realities and come online in time to lower prices and ensure resource adequacy."

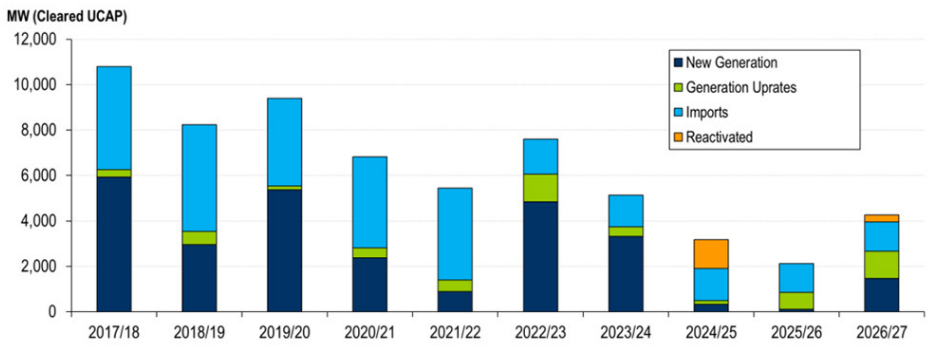
PJM Power Providers Group (P3) President Glen Thomas said the capacity market is successfully delivering reliability at a price that remains below surrounding regions.

"The auction results show a market that is responding but remains tight. New generation is being added, existing generation retained, external capacity imported and retired capacity reactivated. The resource mix remains diverse, and it is important for the market to continue to send the signal that more capacity is needed. In the meantime, consumers should feel comforted that PJM has secured capacity commitments sufficient to maintain reliability through May of 2027 at a price below what many other regions of the country are paying," he wrote in a statement.

Electric Power Supply Association CEO Todd Snitchler said the auction prices show new resources, not political interventions, are urgently needed.

"Higher prices are a signal to build more generation resources, and reflect increasing stress on the system," Snitchler said. "In recent years, a combination of state and federal policy shifts and poor market signals led to the premature retirement of essential generation. Now, as demand grows and supply tightens, we can't ignore the consequences of past decisions, and we must accept that reliability comes at a cost. Investment follows clear, consistent rules."

He argued that competitive wholesale markets have kept energy prices stable and efficient, whereas rising retail rates can be attributed to state policy mandates, as well as transmission and distribution spending not subject to the same transparency and market pressures. ■



Cleared new generation, uprates, imports and reactivated capacity by delivery year | *PJM*

PJM Stakeholders Vote Out 2 Board Members

Motion to Reconsider Scheduled for Upcoming Vote

By Devin Leith-Yessian | Originally Published 5/12/25

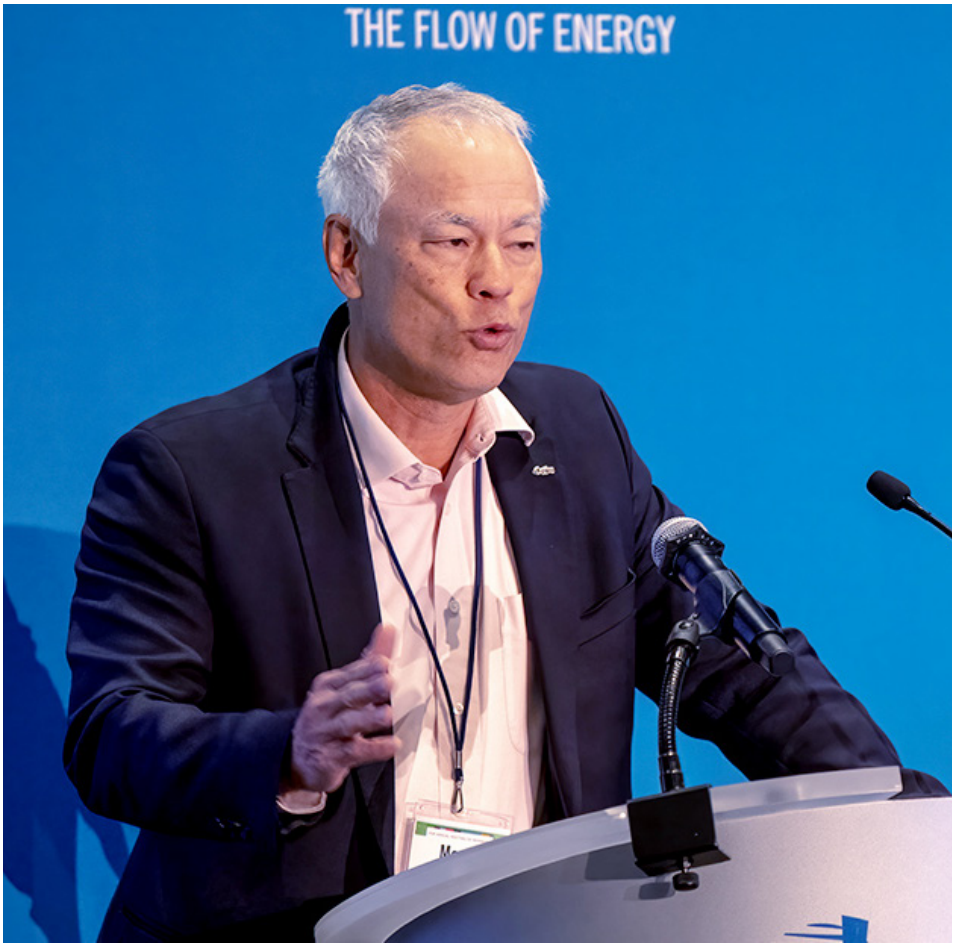
LANSDOWNE, Va. — PJM's Members Committee voted not to reelect two incumbent members of the RTO's Board of Managers: Chair Mark Takahashi and Terry Blackwell.

Committee Chair Lynn Horning, of American Municipal Power (AMP), called the body into recess, following Exelon's motion to reconsider, to allow members time to prepare to cast votes on the motion and potentially a second ballot on the two board members. The committee will return to session on May 13 at 11 a.m. ET.

Takahashi received 30.8% sector-weighted support in the vote, shy of the 50% required to be elected, while Blackwell received 43.5% support. The committee did vote to elect Matthew "Matt" Nelson, principal of regulatory strategy at Apex Analytics, to fill the seat vacated by outgoing board member Dean Oskvig, who is retiring. Prior to his position at Apex, Nelson served as chair of the Massachusetts Department of Public Utilities and worked on Eversource's regulatory policy team for four years.

PJM CEO Manu Asthana expressed disappointment with the results of the vote but said he respects the will of the RTO's members. Asthana noted the board is in the process of searching for his own replacement and will be also seeking a new board member when Charles Robinson steps away next year. (See *PJM CEO Manu Asthana Announces Year-end Resignation*.)

"As the outgoing CEO, I will say there is a lot of change happening at PJM with Dean leaving, with Charlie leaving next year … my experience with both Terry and Mark has been exceptional. I could not ask for more hard-working, dedicated board members," he said.



PJM Board Chair Mark Takahashi | © RTO Insider

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PJM Members Confirm 2 Board Nominees; States Call for Governance Overhaul

PJM's Board Must Protect the Grid

PJM Promotes 3 Executives as CEO Search Continues

In an emailed statement, PJM spokesperson Jeff Shields told *RTO Insider,* "PJM members, via our governing documents, decide who will serve on the independent Board of Managers."

Introducing the motion to reconsider, Exelon's Alex Stern said losing two experienced board members, the sitting chair especially, could cause expertise to drain from PJM at a particularly sensitive time, with looming resource adequacy concerns and an ongoing CEO search.

"We are in the beginning of a historic time, complete with an executive order declaring a national energy emergency," Stern said, pointing to a series of "challenges" facing the RTO, including resource adequacy issues, large load additions and the transition to a new CEO.

"I'd like to ask for a revote. I'm hopeful that some of the folks that voted against may now, given the result, may appreciate the opportunity to consider … the destabilizing influence of what just happened with this vote," he said.

That motion was seconded by Vistra's Erik Heinle, who said he understands the frustration many members feel with PJM's direction over the past year but contended that this is a critical time for the RTO. He said both Takahashi and Blackwell have proven to be excellent board members and that he has appreciated their openness and willingness to reach out to RTO members. He said the results of the vote sent a message to the board that the membership wants to see a change in direction, but that there is no reason to continue down the path of removing two experienced leaders.

Transparency Concerns

LS Power's Marji Philips said PJM members have been extremely disappointed with the direction the board has taken. Without further statements from board members about how they would act differently, she argued there is no reason for members to change their votes on whether to reelect Takahashi and Blackwell.

"It's not just a sign; it's a sign that we want change … so what is the change we could see if we revote this?" she said.

Paul Sotkiewicz, president of E-Cubed Policy Associates, pushed back on the idea that removing two board members would be destabilizing, saying PJM is on a perilous course and a change in leadership is needed to avert a crisis down the road.

"This was clearly a vote of no confidence and to say that this would be destabilizing … I don't think there's been anything more destabilizing than the last few years at PJM," he said.

Members also voiced concern about how a vote to reconsider could be administered. A third-party vendor conducts the vote to elect board members in a portal that provides PJM staff no access to see how individual members have voted. However, PJM Director of Stakeholder Affairs Dave Anders said the vendor cannot change voting on the fly. Therefore, the vote to reconsider would have to be done through PJM software. If the members give the directive, Anders said staff is willing to commit to ensuring that sector and member votes remain private and that the internal audit team can ensure the data is deleted without having been viewed.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), told *RTO Insider* that many advocates feel there has been little improvement since the 2024 Annual Meeting, when the sector voted against reelecting board members Paula Conboy, David Mills and Vickie VanZandt out of frustration with the design of the capacity market and a proposal to shift filing rights over regional planning from PJM's membership to the board. (See *Stakeholders Re-elect 3 PJM Board Members Over Consumer Dissent*.)

Poulos said consumer advocates have supported several major board decisions — such as renewing the Independent Market Monitor's contract and modeling the output of resources operating on reliability-must-run (RMR) agreements as capacity. But even in those instances, he said, the board acted with little transparency and rushed through the stakeholder process, leaving advocates feeling their perspectives were not sought.

Poulos stressed that the advocates who voted against reelecting Takahashi and Blackwell did not do so out of opposition to them as individual candidates, but because there's no other way to hold the board accountable, given that it meets in private and acts as a body. He noted that board member David Mills told the committee on April 12 that the board is planning to add a standing agenda item to the end of future MC meetings where attending board members will speak with stakeholders with the hope of providing more transparency. ■

PJM Board Approves $6B in Grid Upgrades

By Devin Leith-Yessian | Originally Published 2/27/25

The PJM Board of Managers on Feb. 26 approved a $6 billion package of grid upgrades that includes expanding the 765-kV backbone east to meet rising demand, particularly in Northern Virginia's Data Center Alley.

PJM's recommended slate of projects includes Window 1 of the 2024 Regional Transmission Expansion Plan, as well as a doubling of the cost estimate for grid reinforcements needed to allow the deactivation of Talen Energy's Brandon Shore generator outside Baltimore from $738.83 million to $1.5 billion. (See "RTEP Changes Include Doubling of Tx Costs for Brandon Shores Deactivation," *PJM TEAC Briefs: Feb. 4, 2025*.)

"A strong, efficient transmission system enables economic growth and ensures reliability for consumers across the PJM region," PJM's Executive Vice President of Operations, Planning and Security Aftab Khan said in an *announcement* of the approval. "These projects are especially critical to reliably meet the increasing demand for electricity and leverage new generation resources."

The expansion of the 765-kV network, which accounts for the bulk of the cost, would proceed in two regions: one to the north running from the John Amos substation in West Virginia to the Doubs substation in Maryland, and a second to the south linking the existing network looped into Joshua Falls in Amherst, Va., to a new substation, named Yeat, in Fauquier County to the north.

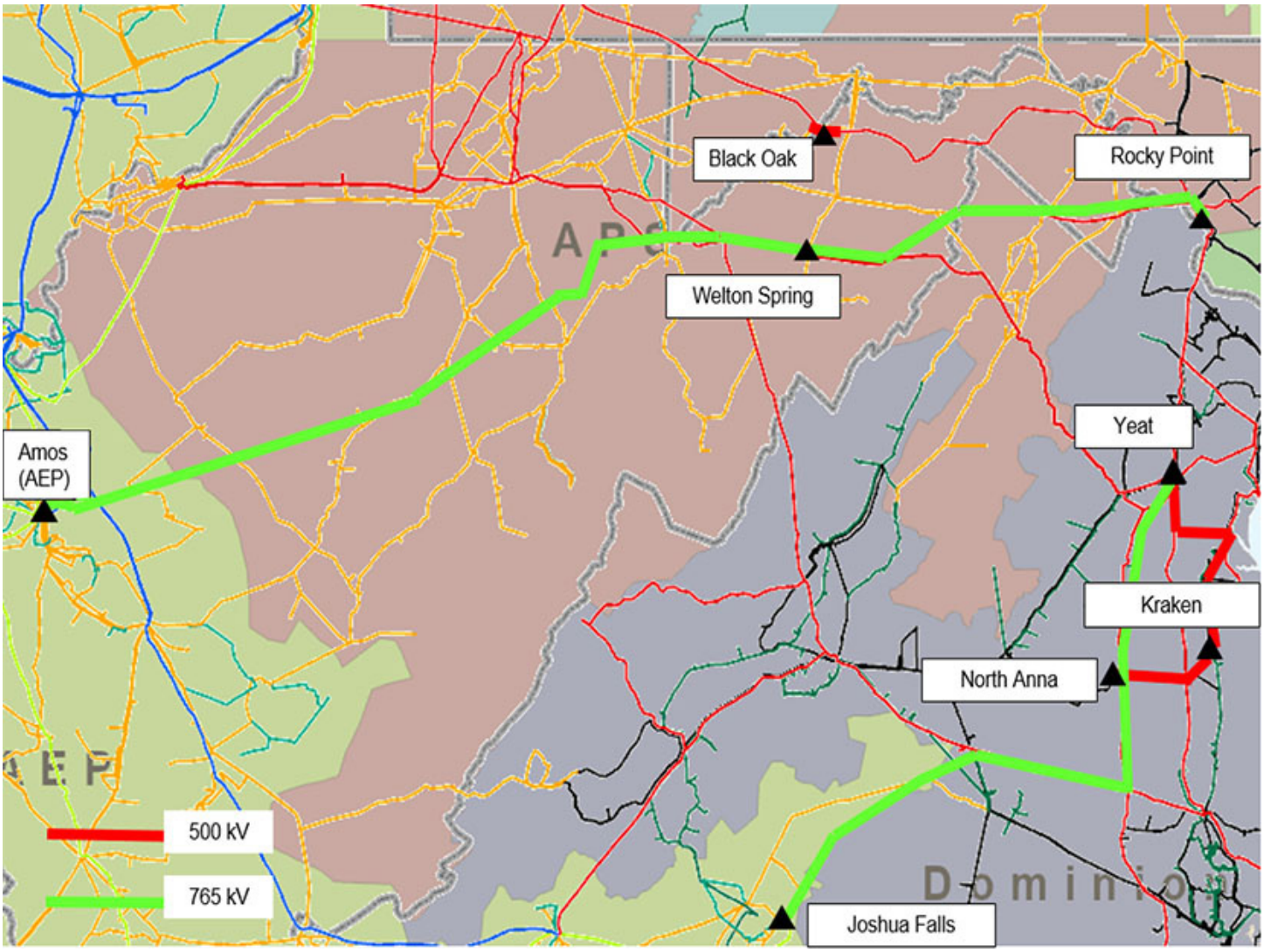
Related Stories

PJM Presents Shortlist of RTEP Projects

FERC Approves PJM 2024 RTEP Cost Assignment

FERC Opens Door for PJM to Refile RTEP Protocol Proposal

The northern corridor would use a mix of greenfield and existing rights of way between Joshua Falls and the Welton Spring substation, which would be upgraded with a new 765-kV switchyard, four 250-MVAR shunt reactors and a 500-MVAR synchronous compensator (STAT-



Network upgrades planned as part of the first window of the 2024 Regional Transmission Expansion Plan (RTEP) | *PJM*

COM). The line would continue to Doubs mainly following existing ROW and then to a new Rocky Point substation sited nearby. The new facility would be looped into the 500-kV Doubs-Goose Creek, Doubs-Aspen and Woodside-Goose Creek lines and would feature 765- and 500-kV yards; two 765/500-kV transformers; two 765-kV and two 500-kV, 250-MVAR capacitor banks; and a 500-MVAR STATCOM. Upgrades would also be made to the Joshua Falls, Doubs and Black Oak substations.

PJM's analysis *report* accompanying the recommended projects states that the proposals to upgrade the corridor between John Amos and Rocky Point to 765 kV was selected to provide scalability and flexibility to address load growths and changes in the resource mix beyond the RTEP horizon. A newly implemented 15-year analysis found anticipated violations that would be resolved by the proposal. The work was assigned to American Electric Power, FirstEnergy and Trans-Allegheny Interstate Line Co. (TrAILCo), the latter of which is a FirstEnergy subsidiary. It is expected to cost $1.9 billion, with a required in-service date in June 2029 and projected in-service date in December 2029.

The southern Joshua Falls-Yeat line would mainly follow existing ROW, with some greenfield components. Yeat would be cut into the 500-kV Bristers-Ox, 500-kV Meadowbrook-Vint Hill and 230-kV Vint Hill-Elk Run lines. The component is estimated to cost $1.1 billion and go into service in June 2029.

The work between Joshua Falls and Yeat also includes the proposed 500-kV "Kraken Loop" branching off the North Anna substation to a new Kraken facility to the northeast and turning back northwest to Yeat. Existing lines between North Anna and the Ladysmith substation would be upgraded to 500 kV, and new lines mainly following existing ROW would be built to Kraken, which would be outfitted with two 1,440-MVA, 500/230-kV transformers. The corridor would continue to Yeat with a mix of greenfield and existing ROW. Upgrades would be made to the North Anna, Ladysmith and Elmont substations.

The RTEP report states that the loop will address load growth expected to the east of North Anna, while also resolving stability and operational constraints. Ties to the 230-kV network around Kraken would be deferred until they are needed and likely pursued through the supplemental planning process. The loop was assigned to Dominion Energy at an estimated cost of $704 million and an in-service date in June 2029.

Several additional project components across the PJM region were included in the RTEP window. An additional $672 million Transource project was selected to upgrade 230-kV and 115-kV infrastructure across the Dominion's footprint, which was assigned the construction as the incumbent transmission owner. The package includes a new 230-kV Elmont-Ladysmith line using existing structures between the two substations; a new 230-kV Raines-Cloud line; and rebuilding two 230-kV lines between the Marsh Run and Remington CT substations.

A $217 million package was approved in the ATSI region to rebuild the 32-mile, 138-kV Greenfield-Beaver line and sections of the Hayes-Avery, Avery-Shinrock and 138-kV Greenfield-Lakeview lines. A $262 million project would reconfigure the 765-kV Maliszewski substation and reconductor the 10.2 miles of the 345-kV Maliszewski-Corridor line and 4.75 miles of the 345-kV Bokes Creek-Marysville line.

Advanced Energy United Policy Director Jon Gordon said the RTEP process fails to consider regional impacts and alternatives to transmission for solving needs identified. He also argued that projects submitted by TOs are planned in isolation and not competitively bid.

"PJM continues with its business-as-usual buildout of local transmission 'reliability' projects that are not part of any kind of comprehensive regional infrastructure planning process. The PJM board just approved $6.7 billion of these transmission projects for this year, up from $5.1 billion in 2024. The five-year cost for these projects is approaching $40 billion," Gordon said. "These costs are passed through directly to ratepayers and are part of the ever-escalating retail electric rate problem that PJM seems to have little concern for." ■

N.J. Confronts Data Center Load Surge

Conference Speakers Say Risk vs. Cost Analysis Will be Key

By Hugh R. Morley | Originally Published 8/10/25

New Jersey faces tough decisions on how to balance the risk of blackouts against the cost of reducing their frequency, speakers said at a resource adequacy forum organized by the state Board of Public Utilities.

Any plan to combat the expected surge in demand from data centers, they said, likely will be fraught with uncertainty because the emerging situation is unprecedented.

Possible strategies mentioned at the Aug. 5 forum include asking data centers to curb their use at high-demand moments, enhancing energy efficiency strategies, going outside of PJM for power and better coordinating distributed energy resources and storage.

In each case, a proper allocation of costs and a benefit-cost analysis will be critical, speakers said at the forum, conducted at The College of New Jersey in Ewing, N.J. The challenge is multiplied by the sheer size of the problem.

"The loads are very difficult to plan for, and they appear very, very quickly," said Tim Gallagher, CEO of ReliabilityFirst.

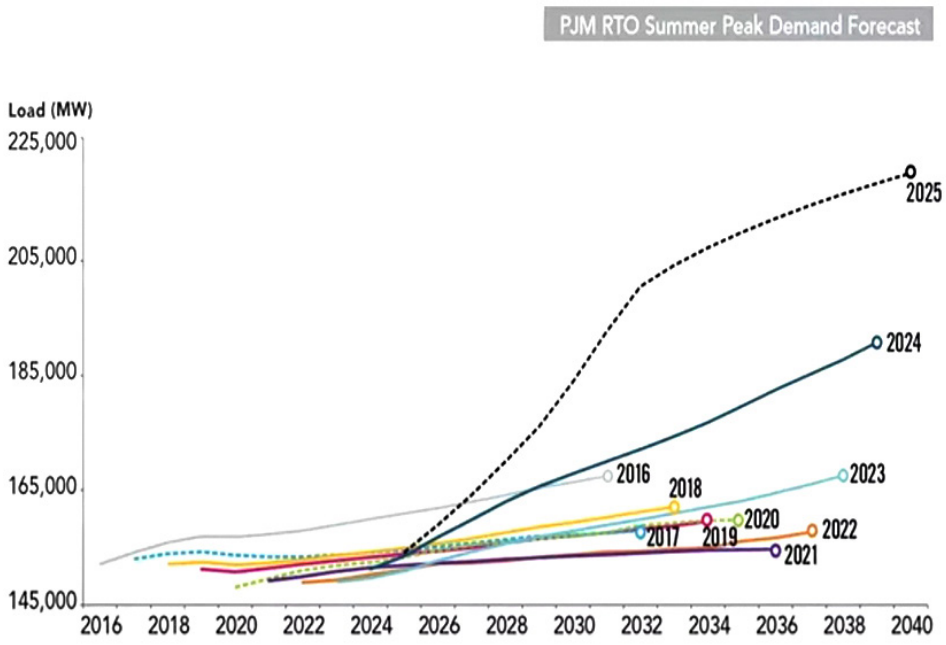
"These things bring very unique and significant challenges to both the planning and the operation of the bulk power system."

Higher Prices Needed

The conference came two weeks after PJM revealed that prices at its July capacity auction soared to $329.17/MW-day (UCAP) RTO-wide for delivery year 2026/27. Prices in the 2024 auction jumped to $269.92/MW-day, the result of load growth, generation deactivations and changes to risk modeling that shrank reserve margins. (See *PJM Capacity Prices Hit $329/MW-day Price Cap*.)

While New Jersey officials have voiced outrage at the auction prices, and a 20% hike in the average electricity bill, the prices still don't stimulate new generation development, warned Richard Levitan, president of Levitan and Associates, an energy management consulting firm.

"We have to be realistic about clearing prices continuing to ascend in order to get price signals to developers for new build," he said. "We could be looking at price signals that are much, much higher, closer to $700 per MW-day."



PJM load forecasts | *NJ BPU*

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Acceptable Power Loss Level

Paul Youchak, of the BPU's office of federal and regional policy, said PJM sets its reliability levels at the commonly held standard of "1-in-10," meaning only one event every 10 years in which the RTO could not meet demand for at least 24 hours.

States that want to lower that risk can invest more in new generation, pushing up costs, he said. He questioned whether "reliability and affordability today … are diverging in a way that hasn't diverged before?"

Gallagher explained that at present, "ratepayers emphasize costs more than reliability," in large part because "we've enjoyed 99.9% reliability for most of our lives." If the state continues on the current path as demand rises, "reliability starts to suffer," he said.

That may trigger calls for a new standard, he said, adding that NERC is moving toward a new standard of "energy adequacy, which is actually studying every hour of the year to make sure you have enough electricity for every one of those hours."

Unified Load Forecast

Whatever standard is in place, the state faces a difficult challenge predicting future load.

Youchak emphasized how suddenly the demand picture has changed. In 2023, he said, PJM predicted that by 2038 the region would have load of about 165,000 MW. By 2025, the RTO predicted the 2038 load would be around 220,000 MW,

an increase of more than one-third.

"It is an order of magnitude difference from the type of volatility we've seen in the past," Youchak said.

New Jersey, with 100 data centers at present, ranks only 15th in the nation, Gallagher said. And they typically aren't the kind of heavy-load artificial intelligence facilities that present the biggest challenges, he said. Instead, New Jersey data centers work to "support government services, public health systems, emergency and disaster response" and other functions, he said.

But because New Jersey is an energy importer, it will be impacted by the arrival of big data centers elsewhere in the RTO region, and "must plan for this rise in demand," said Margarita Patria, a principal of Charles River Associates.

"What's needed is a clear understanding of data center load trajectory going forward," she said. "We need a unified approach in assessing data central load and move to perhaps probability-based forecasting tools that more accurately reflect the state of affairs and will enable more informed decision making."

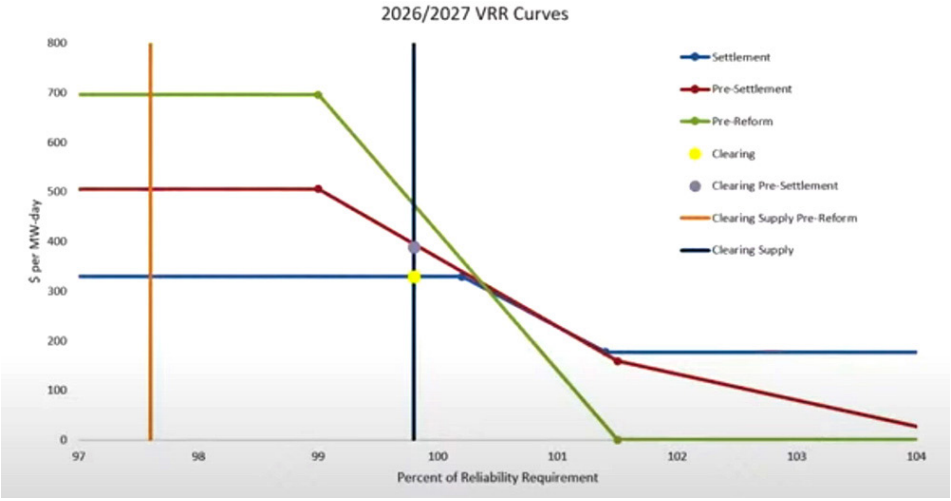
Yet the unique element of hyperscalers, the largest data centers, makes that difficult, said Tom Rutigliano, senior climate advocate for Natural Resources Defense Council.

Traditional statistical methods of basing predictions on past performance have difficulty accounting for the dramatic influx of data sector loads that have no precedent, he and other speakers said. And forecasts may include data center projects that may never come to fruition, speakers said.

Andrew Gledhill, senior analyst for resource adequacy planning at PJM, said the organization is working on "implementation guidelines, talking about the key criteria" that should be included in forecasts, such as "the uncertainty of data center development when you start looking at five to 10 years."

One way to address that is to produce "accuracy metrics on these projections," including after-the-fact scrutiny of data center forecasts to determine "what came to fruition, how did the numbers match up with what they were expecting at the time?" Gledhill said.

The shifting demand profile of the region has added to the importance of getting the forecasts correct. Part of the challenge is that the highest peaks are now in the winter. A loss of power can plunge residents into darkness and cold and create much more severe consequences than in the past, when summer peaks dominated and the main impact was loss of air conditioning.



PJM demand curve | *NJ BPU*

"If we don't have electricity for a sufficient period of time today, people actually die," Gallagher said, citing the dozens of deaths that occurred during power loss triggered by the severe winter storm in December 2022.

In addition, peaks triggered by data centers are more sustained, and so more challenging to handle than the relatively brief demand surges resulting from a cold spell or a heat wave, Gledhill said. Of the 32 GW of demand increase expected in the PJM region by 2030, 30 GW will come from data centers, he said.

"That's generally flat load," he said. "So the load profile, as we move into time, is getting flatter and flatter, which means that there's going to be more hours of risk that pop up."

Managing Demand

Sam Newell, principal with the Brattle Group, said the state should "foster energy efficiency demand response programs," essentially asking users at a "mass market level" to reduce their load at peak times. The state, for example, can set up virtual power plants to manage a network of distributed energy resources, such as solar panels, batteries and electric vehicles, to handle load at peak moments.

Speakers also suggested that big energy users be asked to cut energy use when the overall load gets heavy. But big data centers are reluctant to take that step, in part because "it's difficult for them to predict when an AI-related data center is going to go into learning mode, and that's when their electric demand ramps up significantly," he said.

In addition, Newell said, "a lot of the data centers are not hyperscalers. But they might have 400 to 600 tenants in the data center, and it's difficult for them to pick exactly which ones of those tenants" should take part in demand-response load cuts, he said.

One audience member asked if New Jersey should continue the current level of subsidies for solar when the availability factor — the percentage of its full name plate capacity that it can generate electricity — for solar is only about 11%, due to the limited time in which panels generate electricity. In contrast, *PJM rates* a nuclear generator at 93%, offshore wind at 69% and a gas combustion turbine at 60%.

Rutigliano said the benefit of solar is it's cheap and clean. But he acknowledged that "it doesn't give you a lot of reliability value."

"I'll confess, NRDC's modeling says that the most cost-effective way to a low-carbon grid is a fossil fleet that's around the same size as what we have now; it just doesn't run very often," he said. "Since the reliability or research adequacy issue is the clear and present one, subsidies now in PJM should be flowing to storage, to wind. Offshore wind actually brings more value than a combustion turbine." ■

2 Companies Withdraw Texas Energy Fund Projects from Consideration

By Tom Kleckner | Originally Published 2/18/25

Two energy companies, citing equipment procurement constraints, have withdrawn projects from the Texas Energy Fund's (TEF) In-ERCOT Load Program. The withdrawals leave 16 projects that have advanced to a due diligence phase (*56896*).

ENGIE Flexible Generation NA *filed* Feb. 17 at the PUC to withdraw its Perseus project, a 930-MW peaking facility, from consideration. The company said it has "become evident" supply chain issues would delay the project's schedule, making it impossible to meet a December 2025 deadline for statutorily mandated initial loan disbursements.

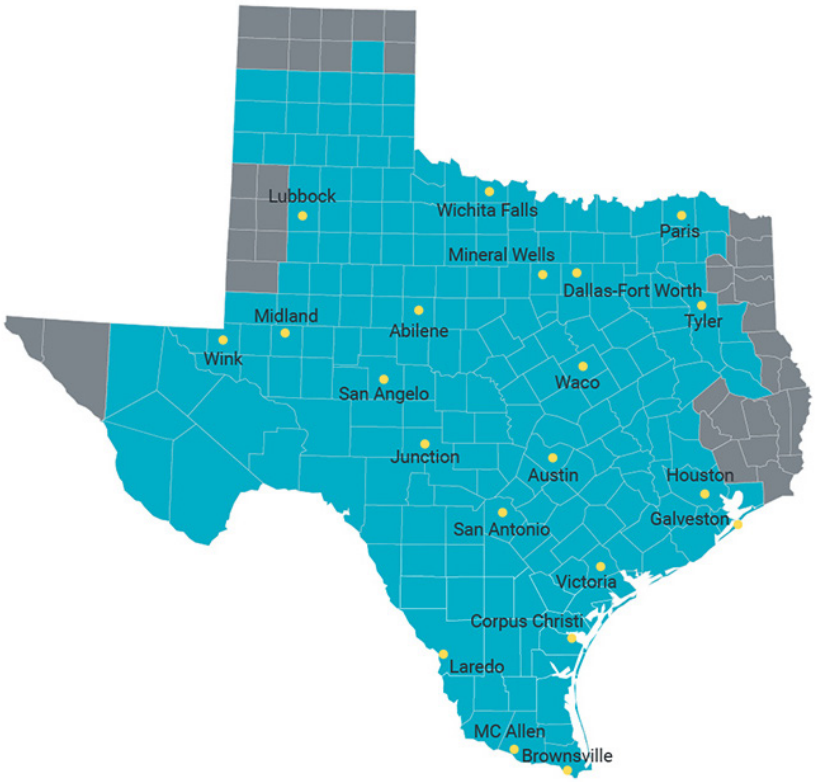
ENGIE also withdrew its Spenser project from further consideration. The project, a 483-MW peaker, did not advance to the due diligence phase.

In January, Howard Energy Partners *withdrew* its co-generation facility at its Javelina processing plant in Corpus Christi, attributing it to similar "equipment procurement constraints." The company said the delays would prevent it from meeting the same December timelines as ENGIE.

The Javelina facility, consisting of a 134-MW combined cycle facility and a 192-MW simple cycle unit, would make 271 MW available for dispatch.

PUC spokesperson Ellie Breed said the PUC anticipates proposing an additional project or projects for advancement to due diligence to replace the ENGIE project.

The withdrawals leave at least 16 projects in the TEF portfolio, accounting for about 8.5 GW of capacity. Loan information is confidential.



ERCOT's service territory covers 75% of Texas. | *ERCOT*

PUC Approves Non-ERCOT Program

The PUC established another TEF program when it approved a rule during its Feb. 13 open meeting that creates a program for grants to utilities and power generators outside the ERCOT region.

The rule sets up the Outside of ERCOT Grant Program as one of four programs under the TEF, which Texans approved by constitutional amendment in 2023. The grants can be used to finance modernization, weatherization, reliability and resiliency improvements, and vegetation management (*57004*).

"Every corner of our state faces unique weather threats and challenges," PUC Chair Thomas Gleeson said in a statement. "The rule approved today will ensure that the TEF improves electric reliability for all Texans, whether inside or outside the ERCOT region."

The ERCOT region covers about 75% of Texas, except for portions of East Texas, West Texas and El Paso.

ADER Project Moved to ERCOT

The commission endorsed staff's recommendation to move the aggregated distributed energy resources (ADER) pilot project into ERCOT's stakeholder process to determine the best way to move the initiative forward (*53911*).

The action will dissolve the ADER Task Force, which was created in July 2022. Its work has resulted in *three virtual power plants*, or ADERs, participating in the wholesale energy market and providing certain ancillary services. The ADERs can provide 25.5 MW of energy, 111 MW of non-spin reserve service, and 8.7 MW of ERCOT contingency reserve service.

"The pilot can only benefit from the larger stakeholder group at ERCOT, and that will facilitate its coordinated growth, along with other projects within the ERCOT market system," PUC staffer Ramya Ramaswamy told the commission. She also recommended the grid operator file progress reports every six months. ■

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Texas PUC Approves $240M in Energy Fund Grants

ERCOT: New Ancillary Service Key to Resource Adequacy

MISO Requires Load Shed in New Orleans to Avoid Grid Instability

By Amanda Durish Cook | Originally Published 5/26/25

MISO initiated an hourslong load shedding event in greater New Orleans over Memorial Day weekend with nuclear power outages appearing to play a role.

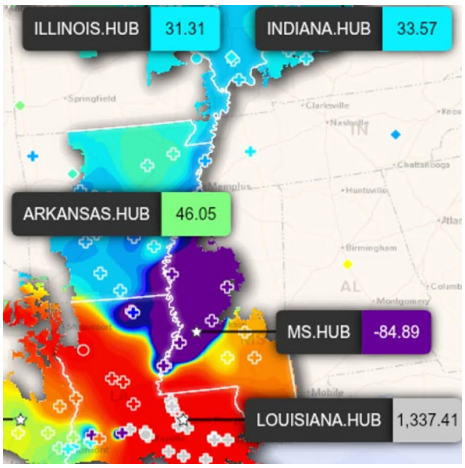
The RTO said on *X* that it ordered Entergy and Cleco to drop about 600 MW on the evening of May 25 to "maintain the reliability of the bulk electric system."

"High temperatures in Louisiana led to higher-than-expected demand, and with planned and unplanned transmission and generation outages, MISO needed to take this action as a very last resort. MISO is coordinating closely with Entergy and Cleco to restore power as quickly as possible," MISO wrote at the time.

Entergy New Orleans and Entergy Louisiana reported they initiated the rolling blackouts on MISO's orders around 5 p.m. CT. Entergy said the "last resort" actions were to "prevent a more extensive, prolonged power outage that could severely affect the reliability of the power grid."

"MISO is directing actions to be taken to restore the system to normal operations as quickly as possible and will direct Entergy to stop these outages as soon as the power shortfall no longer threatens the integrity of the rest of the electrical power system," Entergy said in a *press release* at the time. Later that day, the utility issued a second release announcing MISO canceled further period load shed. Entergy said it would work with MISO to understand the sudden load shed directive.

Local news outlets reported that more than 100,000 customers around New



MISO pricing the evening of May 25 | *MISO*

Orleans were impacted by the controlled outages. Entergy said it restored power around 8 p.m. CT. Entergy and Cleco's territories in Orleans, Jefferson, St. Tammany, St. Bernard and Plaquemines parishes reportedly were affected.

Cleco also *confirmed* it instituted rolling outages on MISO's instructions.

"If the power supply cannot meet the demand, periodic power outages could be needed to protect the stability of the power grid and prevent widespread lengthy outages," said Jennifer Cahill, director of corporate communications. "This was the case yesterday when we took the unprecedented step, as directed by MISO, to force outages to some customers in St. Tammany Parish."

RTO Insider has reached out to MISO for further comment. MISO's real-time market *notifications* don't list any emergency steps that might have preceded the event.

River Bend Station | *Entergy*

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MISO to Debut Tx Warning System in 2026

IMM Advises Better Constraint Management After MISO Tx Emergency

MISO: New Orleans Area Outages Owed to Scant Gen, Congestion, Heat

The outage could be the result of hot weather and nuclear power unexpectedly going offline.

Louisiana Public Service Commissioner Davante Lewis said Entergy's 974-MW River Bend Nuclear Station in St. Francisville, La., tripped offline May 25 as Entergy attempted to restore it to service. The unexpected outage reportedly occurred at the same time Entergy's Waterford nuclear plant in Killona, La., was on a scheduled outage. The Nuclear Regulatory Commission *listed* both reactors as offline before the holiday weekend.

Meanwhile, temperatures around New Orleans registered at about 90 degrees Fahrenheit.

Lewis told local station *WWL-TV* that the simultaneous scheduled and unscheduled outages should not have risen to a load shedding event. "That means there's more to the story — either bad forecasting, bad modeling or higher demand than was projected," he said.

Fellow Commissioner Eric Skrmetta said the load-shed orders arrived less than three minutes before action was required so utilities didn't have the option to cut interruptible industrial customers first in an attempt to reduce demand. He said the notification time was "unacceptable" and said upcoming commission meetings would focus on appropriate notification times from RTOs before delivering load shed instructions.

Until now, MISO had directed load shedding just once in the past 17 years, ordering about 700 MW offline in MISO South during Winter Storm Uri in early 2021. ■

How Much are Batteries Displacing Natural Gas on CAISO's Grid?

Displacement Depends on Weather, Time of Year, Behavior of Storage Resources

By Ayla Burnett | Originally Published 1/5/25

More than 11,000 MW of battery storage resources are now deployed across CAISO's grid — with much more on the way.

But how much are California's batteries really displacing gas-fired generation?

Answering that question isn't easy, according to CAISO staff and other electric industry experts, who say that while batteries are having a notable impact, several factors — including weather conditions and the behavior of storage resources — complicate the narrative that they are displacing gas on the grid.

"You can confidently say that batteries are displacing the need for natural gas energy production, but — and this is a large 'but' — batteries are not displacing the need for natural gas capacity just yet," Carrie Bentley, CEO and co-founder of Gridwell Consulting, told RTO Insider.

Battery buildout has coincided with the need for additional capacity to ensure reliability, especially as 2024 saw another record-breaking year for high temperatures. Reliability modeling indicates that most, if not all, of the gas fleet is still needed, as well as all the current and planned batteries for the next decade, Bentley added.

"This is not as bleak for the environment as it sounds because batteries are displacing the gas fleet energy production and therefore lowering natural gas emissions," Bentley said.

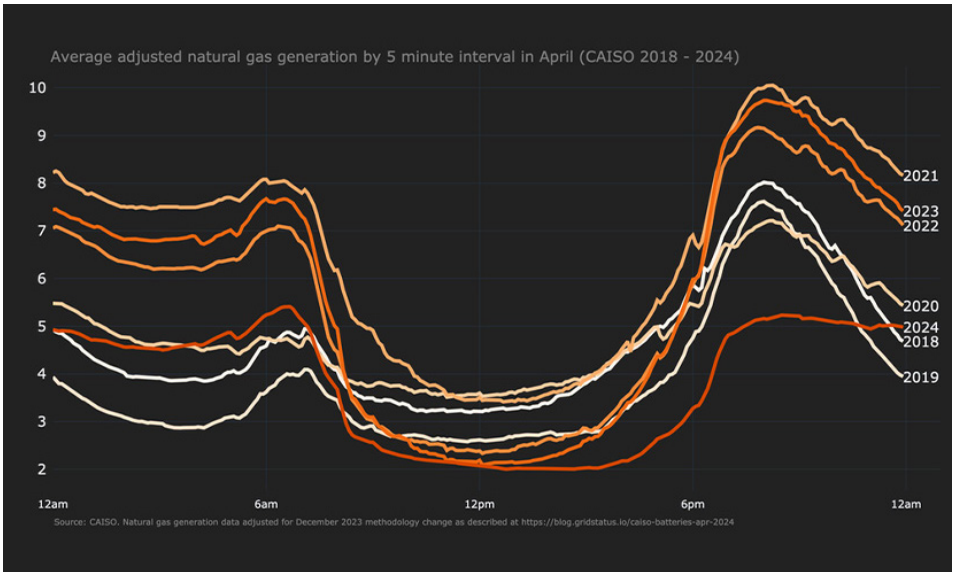
No 'One-for-one Displacement'

Energy storage capacity on the CAISO grid grew from under 500 MW in the summer of 2020 to 11,200 MW as of June 2024, representing a "significant" pace of deployment, Sergio Dueñas Melendez, the ISO's battery storage sector manager, said in an interview with RTO Insider.

CAISO's Western Energy Imbalance Market includes an additional 3,500 MW of battery capacity, according to a June 2024 *report* from the ISO's Department of Market Monitoring.

While Dueñas Melendez noted that the ISO does not currently have a metric to determine whether batteries have displaced the need for gas on California's grid, the addition of energy storage has had an obvious impact.

"Now that we have way more batteries, we definitely are seeing that batteries are charging in periods of high solar radiation and discharging as the sun starts to set into the afternoon peak and the peak hours," Dueñas Melendez said. "Earlier this year, the ISO broke a record of peak battery discharge, with over 7,000 MW in a given five-minute interval of battery discharge."



Average adjusted natural gas generation by five-minute interval in April from 2018 to 2024 | *Grid Status*

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CAISO Monitor Sees 'Gaming' Potential in Battery Storage Bid Cost Recovery

Home Batteries Provide 535 MW to CAISO Grid on VPP Test Day

Battery Storage Revenue Average Trending Down in California

Pointing to data from the DMM showing the change in hourly generation by fuel type between 2022 and 2023, "you can see how gas, on average, especially in certain hours, has reduced its output, and batteries have increased their output," CAISO COO Mark Rothleder told *RTO Insider*.

But the behavior of batteries complicates making an exact calculation of the level of displacement.

"You will not see a one-for-one displacement because a four-hour battery is not going to perfectly displace a dispatchable gas resource over the day," Rothleder said. "The capability of the batteries over four hours versus being able to ramp day-over-day and intraday of the gas fleet doesn't allow you, at this point, to fully replace the gas fleet with batteries. But there is certainly energy displacement."

Guillermo Bautista Alderete, CAISO's director of market analysis and forecasting, added that a one-to-one replacement of gas with storage supply cannot be assumed because of the dozens of storage and gas resources with varying costs and locations. He also noted that, given the level of storage in the system, those resources can also be displacing of other types of supply, not just gas — the exact value of which is also unclear.

"Since the market determines the optimal

dispatch of all resources based on their bid costs and attributes, it can't precisely track in isolation the specific volumes of gas supply displaced by storage resources compared to other supply types," Bautista Alderete said in an email. "Changes in the level of gas supply dispatched at any given time depend on various factors, including the relative bid costs of different technologies, demand levels, hydro conditions, renewable production, resource availability, gas prices, seasonal conditions, transmission congestion and broader supply/demand conditions in the WEIM that influence the level of transfers."

Weather Impacts

The degree to which batteries displace gas can also depend on prevailing weather conditions.

A May 2024 blog *post* from energy data provider Grid Status contended that battery storage was the "standout performer" in CAISO last spring, saying that "batteries are displacing natural gas when solar generation is ramping up and down each day in CAISO."

But the report only cited data from April, which does not show the full picture, according to Bentley.

"April is not indicative of the annual trend, because what's happening in April is you have very low demand, but it's starting to get sunny," she said. "This is basically the perfect time for batteries."

California successively broke records for summer heat in 2023 and 2024, which drove high — although not record —peak loads. While natural gas usage remained high, it decreased as batteries grew, even as peak demand increased.

According to CAISO data, the ISO's 2023 peak demand occurred on Aug. 16 at 44,534 MW. In the early evening hours, as solar ramped down, natural gas peaked at 26,490 MW, with batteries dispatching at 927 MW. As the evening progressed, batteries ramped up, peaking at nearly 3,000 MW, while natural gas ramped down to just over 25,000 MW.

The 2024 peak of 48,353 MW occurred on Sept. 5. As solar ramped down in the early evening hours, both gas and batteries ramped up well into the night. Despite the increased net demand and record-breaking heat compared with the prior year, the natural gas peak topped out at just over 23,000 MW, while battery output rose to over 6,000 MW — reflecting a seasonal pattern that resulted in an "uneventful" summer despite periods of extreme heat, according to CAISO. (See *Batteries, Energy Transfers Support 'Uneventful' Summer in West*.)

When considering different periods and associated trends, all system conditions must be considered, Bautista Alderete added.

"The supply mix will inherently be lower across various technologies to meet the demand on a spring day with a peak of 30,000 MW, compared to a much higher supply mix needed to meet the demand on a summer day with a peak of 50,000 MW," Bautista Alderete said. "Naturally, a higher level of supply is required to meet peak demand during the summer."

The growth of battery energy storage in tandem with the decrease of natural gas is expected to continue. The California Energy Commission projected the need for 52,000 MW of battery energy storage by 2045, a goal that CAISO's Dueñas Melendez said the state is on track to meet.

"We have more in the queue than that," Dueñas Melendez said. "The real challenge — across the different agencies, for developers and for the ISO — is to be able to manage that influx in an orderly way to get to that goal." ■

Texas PUC Approves 765-kV Transmission Option for Permian Basin

Commission: Higher-voltage Lines' Benefits Outweigh Costs

By Tom Kleckner | Originally Published 4/24/25

In what is being labeled a "landmark" and "historic" decision by the industry, the Texas Public Utility Commission approved a plan April 24 that allows ERCOT to authorize the region's first extra-high-voltage transmission lines and meet the petroleum-rich Permian Basin's rapidly growing power needs.

The PUC unanimously endorsed staff's recommendation to construct three 765-kV import paths into the Permian Basin, where oil and gas electrification and data center announcements have significantly increased load projections. The 765-kV option, while 22% more expensive than the 345-kV option, will carry more than twice the voltage of existing infrastructure. (See *PUC Staff Urges Approval of 765-kV Lines to West Texas*.)

ERCOT and the transmission service providers (TSPs) have said the 765-kV lines can carry more power and meet higher demand levels as the state continues to grow. They can reduce congestion on existing transmission lines and could save money in the long term by eliminating the need to build additional lines.

The TSPs have been preparing certificates of convenience and necessity applications for the projects approved in the plan. "Now that the voltage decision [has been] made, they can begin filing those applications to get the process started," spokesperson Ellie Breed said in an email.

"Our priority now is ensuring utilities execute these projects quickly and at the lowest possible cost to Texas consumers," PUC Chair Thomas Gleeson said in a *statement*.

Staff said the current options have increased to $10.11 billion for 765 kV and $8.28 billion for 345 kV.

"This is really exciting for Texas, when you look back on monumental decisions that affect Texas," Commissioner Kathleen Jackson said during the open meeting. "This will fit in those benchmarks, and we will look back and say this was one of those decisions."

Related Stories

ERCOT Stakeholders Endorse $9.4B 765-kV Build

Texas PUC Approves Permian, Outside ERCOT Transmission Projects

Patton Calls on ERCOT to Operate its System Less Conservatively

The PUC's decision came after a monthslong review process that included three public workshops and three rounds of stakeholder feedback. Commission staff conducted a full analysis of the costs, equipment supply chains and project-completion timelines for both voltage options, gathering input from the public, equipment manufacturers and the transmission companies that will build and operate the new lines.

The commission's order does not apply to ERCOT's plans to add an EHV backbone to the rest of its system. The grid operator said it will work with the PUC and stakeholders to include the higher voltage in its study process.

ERCOT included a 765-kV study as part of its annual *Regional Transmission Plan* (*55718*). (See *765-kV Lines in West Texas Inch Closer to Reality*.)

The Texas Advanced Energy Business Alliance (TAEBA) applauded the PUC's decision, saying in an email the "historic vote" ushers in a "new era of grid modernization for the Lone Star State."

"This decision brings ERCOT into the 21st century," TAEBA Executive Director Matthew Boms said. "As electricity demand surges, we need a grid that's built for the future — reliable, efficient and cost-effective. Today's vote is a strong step toward that goal."

American Electric Power *trumpeted* the fact that its Texas subsidiary will build one of the three import paths into the Permian Basin as part of a jointly assigned project. The 300-mile line will run from Fort Stockton to San Antonio.

AEP energized its first 765-kV operational transmission line in 1969 between Kentucky and Ohio. It now owns 2,110 miles of 765-kV facilities, more than any other system in North America, it said.

The commission also endorsed a *petition* approving assignments to the TSPs to own, construct and operate the Permian Basin projects (*57441*).

"I want to further clarify the commission is not deciding in this proceeding any requirement for a TSP's CCN," Gleeson said. "Those will be decided in the future."

At the PUC's direction, ERCOT filed its *reliability plan* for the Permian Basin in July 2024. The plan included the 345- and 765-kV import paths and a 2038 need date. The commission *approved* the plan in October 2024 but reserved a decision on the voltage level by May. (See *Texas PUC Approves Permian Reliability Plan*.)

4 Projects Added to TEF

The PUC approved *staff's recommendation* to advance four generation projects, totaling more than 1,900 MW of capacity, to the *Texas Energy Fund*'s due diligence review.

The low-interest loan program, designed to add 10 GW in gas generation, has seen eight projects drop out or be removed in recent months (*56896*). (See *2 More Projects Fall out of TEF Loan Program*.)

The projects belong to independent power producers Invenergy and Nightpeak Energy. Invenergy proposed two projects totaling 1,369 MW of capacity, and Nightpeak has applied for loans to cover 565 MW. That raises the TEF In-ERCOT Program portfolio to 18 projects, promising 9,218 MW and requesting $5.04 billion in loans. Texas lawmakers have already set aside $5 billion for the program.

"These are taxpayer dollars, and this is

our program. We set the rules, and at the end of the day, you have to have the ability to repay, and you have to have the ability to execute," Gleeson said. "Inherent in getting public funds is a trust from the public that they'll be spent correctly, and I think our due diligence process is helping to ensure that."

The commission also approved the first recipient of the TEF's *Completion Bonus Grant Program*, which awards grants to companies that add at least 100 MW to the ERCOT grid through new construction or by expanding dispatchable generators that meet the TEF's requirements.

The Lower Colorado River Authority is seeking *$22.5 million in loans* to help build the first of two 188-MW gas-fired units at its *Timmerman Power Plant*. The PUC can award LCRA a maximum of $120,000/MW (up to $22.5 million) if the unit connects to ERCOT before June 1, 2026. The facility will be tracked annually for 10 years and must meet specific performance and reliability measures and is available to ERCOT dispatch.

The unit is scheduled to reach commercial operations in 2025.

"It's just good to see LCRA coming forward and taking advantage of this," Jackson said. "It's 10 years of oversight and performance, incentivizing them to be able to get the full grant."

Braunig RMR Work Delayed

ERCOT staff *told* the commission that a crack in Braunig Unit 3's boiler superheater header will require that the header be replaced, "significantly extending" the unit's potential return to service as late as spring 2026 (*55999*).

CPS Energy found the crack during its maintenance outage, which began March 3 as part of the unit's reliability must-run agreement with ERCOT. The San Antonio municipality announced in 2024 it would be retiring the 55-year-old gas unit along with Braunig's other two units, but the Texas grid operator said it was still needed for reliability reasons. (See "RMR Contract for CPS Energy Unit Faces Increased Costs, Delays," *ERCOT Board of Directors Briefs: April 7-8, 2025*.)

David Kezell, ERCOT's director of weatherization and inspection, said a new superheater will have to be built specifically for Braunig 3. Ideally, he said, the unit could be operational for the 2025/26 winter. The superheater is expected to cost about $3 million but is within the outage's current $25 million budget, Kezell said.

"The budget is in reasonable shape," he said.

ERCOT and the market already are on the hook for $45.85 million under the terms of Braunig 3's RMR.

Kristi Hobbs, vice president of system planning and weatherization, said ERCOT conducted another analysis to determine whether to proceed with the investment in Braunig. Staff updated their models with load growth and generation studies since their previous study and came to the same result.

"We found that even with a delay, even if it's delayed into February of next year, there is still more benefit than cost to moving forward with maintaining the Braunig unit," Hobbs said. "We see the potential benefit really comes next summer in the July and August time frame … so we still see that benefit of moving forward with the work."

ERCOT counsel Nathan Bigbee told the PUC that ERCOT had reached an agreement with LifeCycle Power, which owns 15 mobile generators that it has leased to CenterPoint Energy, and is proceeding with plans to move the units to San Antonio over the summer. He said cooperation is still needed between CenterPoint and CPS to "make this all work."

"Having a fundamental structure in place for ERCOT and the LifeCycle arrangement will help facilitate those agreements as well," Bigbee said. "This is not like anything else we've had before. We are leveraging the RMR framework for the dispatch, the settlement and the performance metrics for these generators."

The generators, which can produce nearly 40 MW apiece, will be moved to San Antonio in groups of three. They will then be connected in strategic sites to the CPS distribution network.

In other actions that the PUC crammed into just over an hour before adjourning, the commissioners:

- sided with *staff's recommendation* to delay the first procurement for the proposed *firm fuel supply service* (FFSS) until the 2026/27 winter season. The generation service is still going through ERCOT's stakeholder process; staff were also leery of "competing interests" coming out of the Texas Legislature, which ends in early June (*56000*).

Texas PUC Commissioner Courtney Hjaltman shares her thoughts on the 765-kV proposal. | *Admin Monitor*

- approved a joint application by CPS and South Texas Electric Cooperative for certificates of convenience and necessity for a proposed 345-kV project south of San Antonio. The PUC modified the *proposed order* by changing the project's route, which is estimated to cost between $274 million and $390 million. The project is one of several that are part of the San Antonio South Reliability Project addressing a transmission constraint that led to the Braunig RMR. It will be built and owned 50/50 by CPS and STEC (*57115*).
- accepted CenterPoint's request to recover more than $400 million in restoration costs from a series of storms in May 2024. The PUC approved $28.9 million in restoration costs and an additional $396.3 million in expenses to be securitized (*57271*). (See *Texas Public Utility Commission Briefs: May 23, 2024*.)
- agreed to AEP Texas' $318 million, three-year *system reliability plan* that the company says will save about $71 million in projected restoration costs. About 80% of the plan involves replacing aging infrastructure with newer equipment designed to a higher standard that can better withstand extreme weather events, AEP *said* (*57057*).
- welcomed the city of Caldwell, between Houston and Austin, into the ERCOT system by approving an *order* integrating its 14 MW of load from MISO. The city reached an unopposed agreement with PUC staff, LCRA Transmission Services, Entergy Texas and the Office of Public Utility Counsel. ERCOT did not oppose the settlement (*56164*). ■

FERC Dives into Thorny Resource Adequacy Issues at Tech Conference

By James Downing | Originally Published 6/5/25

For most organized markets across most of their history, resource adequacy was relatively easy to handle, with supply long and demand growing slowly.

That has changed rapidly in just the past few years, with a spike in demand growth led by new data centers. FERC spent June 4-5 looking into the issue across the markets it regulates.

FERC Chair Mark Christie has been talking about a reliability crisis for years, as dispatchable generation has retired with replacements that at best do not offer the same characteristics.

"So now the crisis is really right on our doorstep," Christie said. "But let's not forget, while this conference is about the impending crisis of reliability from resource shortfalls, it really has another crisis connected to it, and that is the crisis of rising consumer power bills, because consumers have to pay for capacity, as we all know. And I know that in at least two states in PJM — Maryland and New Jersey — this very week consumers are seeing big jumps in their power bills because of rising capacity costs."

The technical conference, along with pre-filed comments and another round after the conference, will build a record that FERC could use in future proceedings on the issues, he said.

The industry is facing a lot of uncertainty, including extreme weather, supply chain constraints, rising costs for equipment and how much it can really count on demand forecasts, Commissioner Judy Chang said.

"The compounded complexities around the regulatory and commercial structures deployed in various regions across the country make all of our jobs difficult, and that's why we're having this conversation today, to add to the record, but also to add an opportunity to discuss these questions," she added.

NERC has been monitoring resource adequacy for decades, and, outside a few regions, it was mostly boring until 2018, CEO Jim Robb said.

Related Stories

Panelists Say More Work Needed on Large Load Risks

FERC Conference Speakers Emphasize Planning, Collaboration

NERC Staff Call for Resource Accreditation Guideline

"For the first time, in 2018, our long-term resource adequacy assessment showed a material expectation of long-term unserved energy, and 18 months later, that expectation, unfortunately, was realized with a significant load-shed event in California in August of 2020," Robb said. "And since then, our analyses have shown growing risk of unserved energy across the continent."

The theory around resource adequacy in wholesale markets was simple, with trading in spot markets producing price signals that would lead to bilateral deals that can support new entry of generation, ISO-NE CEO Gordon van Welie said.

"The construct assumed that society would be tolerant of occasional shortages and high prices to allow market incentives to work," van Welie said. "In practice, we have learned that the theoretical construct made assumptions that were inaccurate. Specifically, it assumed the proper price formation in the energy market, which has been stymied by price caps and externalities that have not been priced. This has led to the need to replace the missing money."

It also ignored the need for a reserve margin, and in that gap came the capacity markets. Both ISO-NE and PJM have used three-year forward markets, but van Welie said his RTO is working on a prompt, seasonal design that is better equipped to deal with the realities the system is facing.

"The seasonal pricing will reflect the dynamic changes and constraints in the regional power system, provide the economic stimulus to drive bilateral trading and discipline wholesale buyers who have not covered their share of the resource adequacy objective," van Welie said.

The new construct would require support from the states, reduced barriers to entry and substantial bilateral trading to manage volatility and support investment, he added.

PJM's markets have generally worked well in the past, with its capacity market helping to bring online 50 GW of new resources that includes significant renewables and 8 GW of demand response since it launched in 2007, CEO Manu Asthana said.

"So, it's not something very lightly that we would want to move away from," Asthana said. "I think they have worked, but — and there's a 'but' — as you know, we've been expressing resource adequacy concerns for some years now, and they're driven by generator retirements, slow new entry and accelerating demand growth."

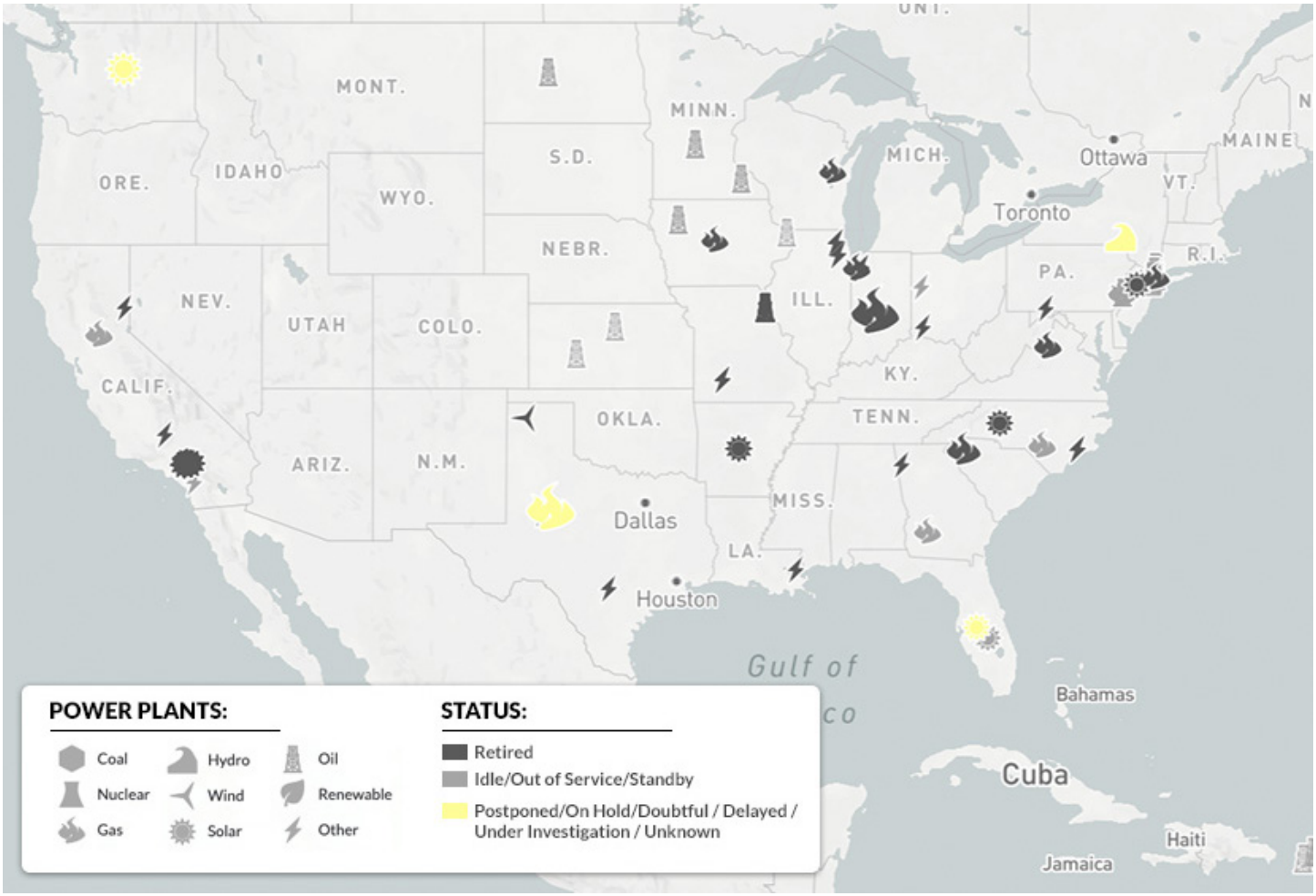
Artificial intelligence is effectively just a "toddler" at this point, with ChatGPT launching less than three years ago, Asthana said. The technology is only to grow, and Asthana said he believes it will change the world — and in the process lead to much higher demand for power.

Other regions have seen their once large reserve margins shrink down to their minimum targets, and that is likely to remain the case.

"We hit minimum planning reserve margins in 2022; we've been treading water to maintain that level ever since," MISO Senior Vice President Todd Ramey said. "I think that's the new normal for our region. All of the incentives do not point to excessive planning reserve margins."

A key way MISO keeps track of resource adequacy is surveys it conducts with the Organization of MISO States, which represents states that are largely vertically integrated. The latest survey June 6 will show the industry in the region has work to do to maintain its reserve margin target next year and for the rest of the decade, Ramey said.

A longer-term 20-year assessment from



A map from Yes Energy showing generation retirements, the rate of which was a key factor prompting FERC's technical conference on resource adequacy this week. | *Yes Energy*

a couple years ago showed only renewables coming online, which would have left the grid short of key reliability services, but Ramey said that has changed for the next long-term assessments as states have added more dispatchable resources to their plans.

For states that have ceded more of the control to FERC, the options to ensure reliability are more limited, with van Welie suggesting some kind of financial hit is needed, such as a penalty baked into the market, or just letting scarcity pricing occur in the spot market.

While restructured states have given FERC more control over resource adequacy, none of them under its regulation has gone as far as to Texas, where the standard utility has been eliminated, leaving large parts of their customers still on utility service. Asthana suggested states could change the rules set for utilities to procure supplies for those customers to boost bilateral trading and supplement the wholesale market.

"Because a lot of the load clears through state-run auctions, I think our states have the ability to try to hedge their consumers through those auctions for capacity," Asthana said. "And I think those hedges and those bilaterals will also incentivize new generation, and those are conversations we're having with our states."

State of PJM's Markets

After an initial panel of ISO/RTO CEOs, the technical conference started focusing on regions, and PJM got the most attention, with three panels taking up more than half a day.

Commissioner Chang noted PJM has seen some of the largest concerns, but paradoxically, it has seen some of the lightest renewable power development, with 93% of its generation still conventional.

Given that PJM is going through more retirements of conventional generation, and most of the new developments are renewables, the mismatch in retirements and replacements is a concern for the near future, and the RTO already has to start planning for it, said Vice President of Market Design and Economics Adam Keech. On top of that, PJM has several hot markets for data centers, with the resulting demand growth acting as an accelerant to every other issue it faces.

Data centers are looking for highly reliable, 24/7 power, but a recent study from Duke University showed that they can be flexible if they use on-site resources such as batteries to participate as demand response, said LS Power Senior Vice President of Wholesale Market Policy Marji Philips. (See *US Grid has Flexible Headroom for Data Center Demand Growth*.)

"It's really only the times the system is stressed that you need the thermal generation," Philips said. "The problem is when it's stressed, you need it all. And PJM, as Adam said, is seeing a retirement of those resources."

Renewables are dominating the queue, and the most economical of those are

going to be built and will benefit the grid and consumers, PJM Independent Market Monitor Joe Bowring said.

"All I'm saying is that there's a baseline level of dispatchable resources you need for reliability to meet the demand during the high expected unserved energy hours," Bowring said. "So, I mean … low-marginal-cost energy is great for customers, but it doesn't meet that same reliability."

The resource adequacy issue and consumer costs in PJM have caused some to question longstanding policies on the market. (See *Utilities Pushing for a Return to Owning Generation in Pennsylvania*.)

But PJM Power Providers President Glen Thomas doubted Pennsylvania will change course and said Ohio just reaffirmed its market-centric policy with a recent change in law. Illinois, Maryland and New Jersey all restructured, and they have moved to a middle path, relying on the markets while being more active in picking resources, which he argued led to the retirements of others.

"They've largely been able to do that because of the tremendous surplus that Pennsylvania has built up," Thomas said. "And I would also add that Pennsylvania would never have been able to build that surplus under a vertically integrated [integrated resource plan] regime. There's no way state regulators would allow the system to be that overbuilt."

Now that excess capacity is bailing out even Virginia, which is a vertically integrated state that is dealing with massive demand growth from its world-leading data center market, he said.

Chair Christie, who was a regulator on Virginia's State Corporation Commission for years before joining FERC and is a strong proponent of its regulatory setup, said traditional regulation worked for years there and only ran into the same issue around unexpected demand growth that is causing issues around the country.

"That was a decision driven by policies adopted by our legislature to give tax subsidies to data centers and other attractions, which the utility commission had nothing to do with," Christie said. "So, the IRP system is not the reason, as Glen said, Virginia is now a big importer."

The prices are getting too high even for Pennsylvania, PPL Chief Legal Officer Wendy Stark said. The capacity market cleared at $270/MW-day last time, which was enough for Gov. Josh Shapiro (D) to file a complaint. That led to a settlement capping the next two auctions at $325.

"That also is not enough to incent new generation, so customers will be paying even more than they are now," Stark said, adding that prices need to be at $500 to $600/MW-day. "That's a problem, and as a utility with that obligation to serve, we at this point are really dependent upon the PJM capacity market. I will tell you at this point that feels like a single point of failure for us."

Pennsylvania and other states restructured because cost-of-service regulation proved inefficient, which meant high costs as well, Bowring said.

"The idea that a regulated generator, because it's subject to a regulatory process, is going to do things more efficiently is questionable," Bowring said. "The markets have demonstrated the reverse for quite some time. So, I didn't think I'd be here jumping up to defend the PJM capacity market."

Bowring also doubted that the mandatory market will ever be meaningfully substituted with bilateral deals because it effectively forces much of that activity into the capacity auctions.

"Cost-of-service regulation worked to provide reliability for 100 years," Bowring said. "It could certainly do that. I think it did it at a higher cost than markets."

Capacity is a political construct, and states should be given more say in how it is managed, said Jacob Finkel, deputy secretary of policy in Shapiro's office. The 14 states that are in PJM are swamped by the sheer number of stakeholders in a process that does not give them major formal input, he said.

"Most of our ability right now revolves around whatever goodwill we can build with PJM around working with the board and working with management, and it should be more than that," Finkel said.

With the disconnect between price signals and new supply as the balance is only getting tighter, Finkel suggested that PJM needs to embrace resources such as virtual power plants (VPPs) and grid-enhancing technologies (GETs) that can be added to the grid quickly.

"All the acronyms should be deployed," Finkel said.

Getting such resources will help, but after the quip, Finkel said ultimately if the issues around the market cannot be resolved in a way that is fair for ratepayers, Pennsylvania could move back to its own planning. ■

State	New Entry Placed Into Service Since 2015 (UCAP MW)	Deactivations** Since 2015 (UCAP MW)	Net New Entry Placed Into Service Since 2015 (UCAP MW)	Resources With Executed Interconnection Agreements/WMPA (Planned Resources) but Not In-Service (UCAP MW)	Net New Entry Since 2015 with Planned Resources (UCAP MW)
Delaware	243	441	(198)	79	(119)
Illinois	3,277	3,016	261	984	1,245
Indiana	915	820	95	1,820	1,915
Kentucky	60	907	(847)	99	(748)
Maryland	2,078	3,114	(1,037)	788	(249)
Michigan	933	-	933	43	976
New Jersey	2,074	4,696	(2,622)	773	(1,849)
North Carolina	196	270	(74)	196	122
Ohio	5,582	9,663	(4,081)	1,853	(2,228)
Pennsylvania	9,025	5,543	3,482	439	3,921
Tennessee	-	33	(33)	-	(33)
Virginia	3,850	4,211	(362)	1,612	1,250
West Virginia	163	1,353	(1,190)	1,565	375
TOTAL	28,395	34,068	(5,673)	10,251	4,579

A chart PJM filed for the FERC technical conference laying out changes in capacity by state over the previous decade. | *PJM*

Data Centers' Reliability Impacts Examined at FERC Meeting

By James Downing | Originally Published 8/17/25

Sudden trips offline by data centers in Virginia and cryptominers in ERCOT present new reliability challenges that must be managed, NERC Chief Engineer Mark Lauby told FERC at its monthly open meeting April 17.

The grid in Loudoun County, Va., home to the largest concentration of data centers in the world, was experiencing some voltage sensitivities last summer, Lauby testified.

"In July 2024 we saw about a 1,500-MW drop as a result of some system conditions — in this case, switching after a fault on the system," Lauby said. "And within 50 seconds, three of those voltage excursions occurred, and the load is monitoring that, and when it sees that happen, it comes offline because it wants to protect its cooling load."

NERC released a *report* on the incident in January that details the grid conditions before and after the data center load went offline. (See *NERC Report Highlights Data Center Load Loss Issues*.)

A similar event happened in Loudoun and neighboring Fairfax County, where 1,800 MW of load suddenly dropped off the system. Lauby said while that is still being investigated, he suspects it will be similar to the July 2024 incident.

Texas has seen more frequent but smaller events as grid conditions have caused cryptocurrency mining facilities to trip offline 25 times between November 2023 and this January, leading to 100 to 400 MW of losses in each incident.

"Historically, if we lose generators, it can trip off the grid," FERC Chair Mark Christie said during the meeting. "Now we've got another issue, which is if large load users simultaneously go off together, it affects the frequency and potentially trips off the whole system."

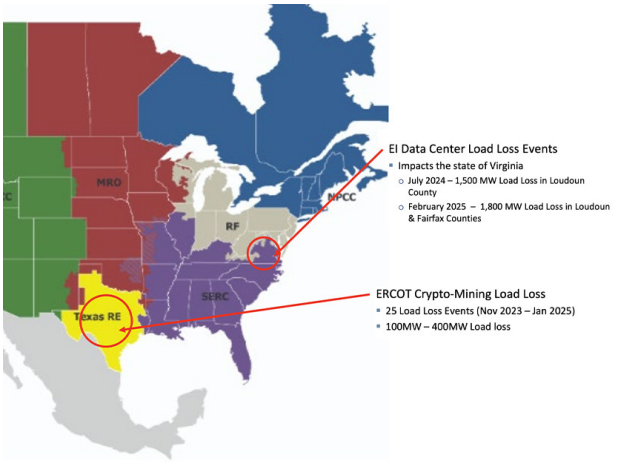
The grid can be engineered to avoid those cascading outages across multiple data centers to avoid a situation where the grid's largest single contingency comes from demand (as opposed to a large power plant or transmission line), Lauby said.

"That comes down to engineering, modeling and continuing to work with the industry — in this case, the large load industry and the power industry — to see how we manage that interconnection," he added.

NERC is considering rule changes to deal with the newfound risk, which is going to be exacerbated as individual data centers' load grows to the size of major cities. The grid has dealt with large industrial facilities at 100 to 200 MW for decades, but some of the proposals for large data centers run to thousands of megawatts, which compares to the total loads of San Francisco or D.C. in a single place, Lauby told FERC.

"We need to, obviously, make sure that's managed well, and the engineering is done to ensure that we minimize the chances for things to happen," he added.

NERC stood up a Large Loads Task Force in 2024 that is expected to issue papers and guidelines to address the risks associated with the issue. The ERO is also working on industry guidance on large loads, incorporating work from the task force.



A slide from NERC Chief Engineer Mark Lauby's presentation to FERC detailing recent reliability incidents caused by data centers tripping offline. | *NERC*

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Parties Warn FERC that Jurisdictional Fight Could Slow Data Center Connection Effort

State Regulators Ponder Federal Role in Large Load Interconnections

Energy Secretary Asks FERC to Assert Jurisdiction over Large Load Interconnections

Part of that analysis is to determine how to register the loads, either by requiring the customers themselves to register with NERC, or if that is not legally feasible, then getting their load-serving entities to do it for them, Lauby said. Then once the facilities are registered, NERC will craft reliability standards so that the chances of such incidents are minimized.

"Large numbers actually really scare me; the potential reliability impact of these drops sound pretty severe," Commissioner Judy Chang said.

Modeling can help NERC secure the grid against uncontrollable outages of data centers; Chang asked what kind of data are needed to effectuate that.

Losing 1,500 MW of load is akin to one and a half large nuclear units tripping offline, but the grid has reserves that can maintain reliability in such cases, Lauby replied. NERC has the authority to get data from the industry under the Federal Power Act.

"For the loads, they've just been good enough to work with us," Lauby said. "And, so, is that going to be good for the long term? Probably not … [it's] something we need to think about."

Large loads tripping offline is one part of the reliability equation when it comes to data centers, with the other key part being meeting their demand with an adequate supply of resources, Lauby said.

"The definition of reliability is adequacy and operation reliability," he said. "So, we've got both problems." ■

US Grid Has Flexible 'Headroom' for Data Center Demand Growth

Duke U. Study Finds 126 GW of Capacity if Data Centers Curtail Peak Electricity Use 1%

By K Kaufmann | Originally Published 2/11/25

A *new study* from Duke University says the existing power system could handle 126 GW of new demand with no additional generation if artificial intelligence data centers can be persuaded to cut their energy use by as little as 1% during times of peak demand.

The "Rethinking Load Growth" report looks at 22 balancing authorities — RTOs, ISOs and large investor-owned utilities — representing 95% of the country's peak load and finds that each could add varying amounts of new load without exceeding its maximum capacity "provided the new load can be temporarily curtailed as needed."

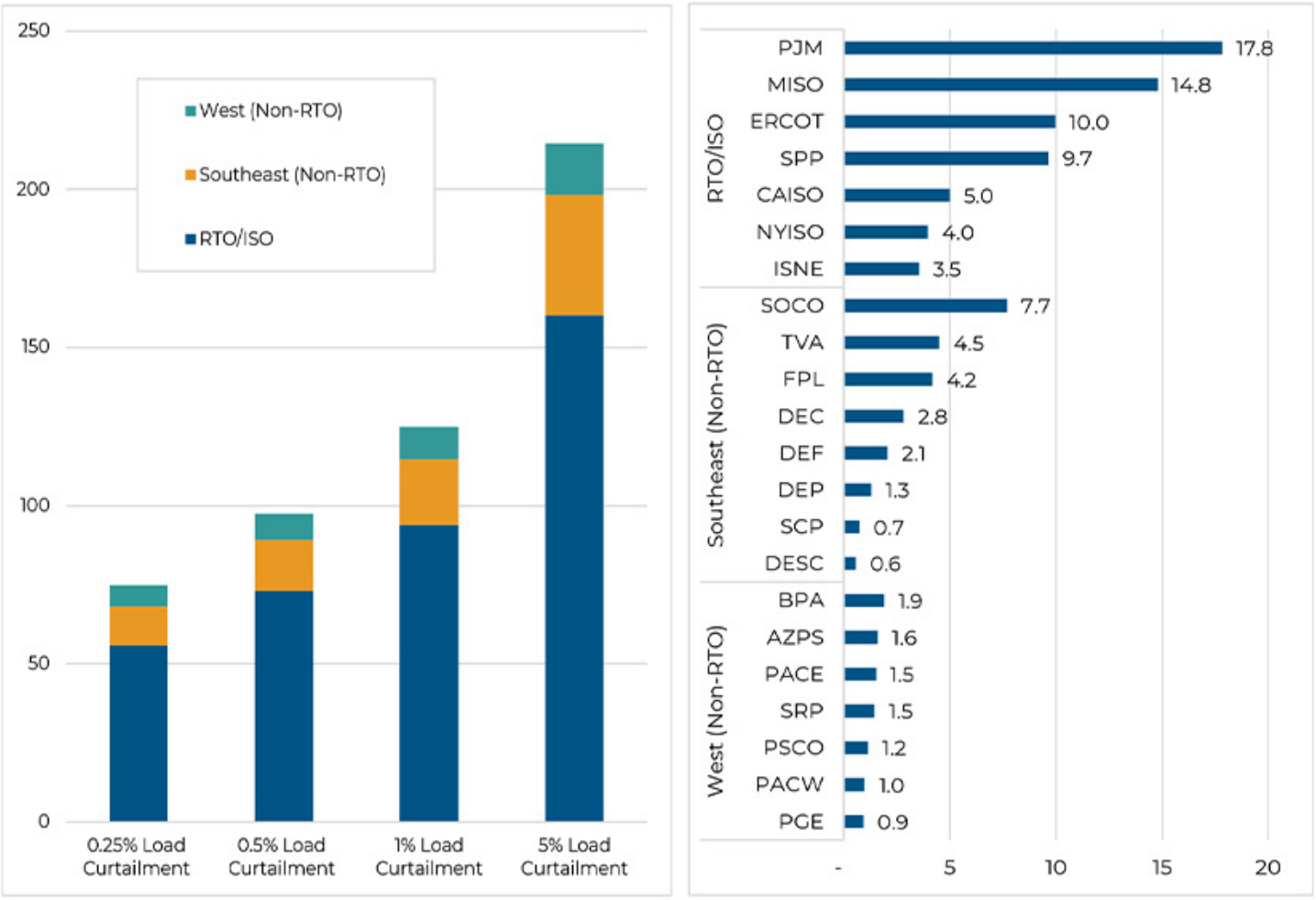
The report defines system curtailment, or flexibility, as a data center's ability to temporarily reduce its power consumption "by using onsite generators, shifting workload to other facilities or reducing operations," thus creating "curtailment-enabled headroom" to add new load.

For example, the study estimates PJM could integrate more than 23 GW of new load with curtailment-enabled headroom based on 1% curtailment. ERCOT could add 14.7 GW, and Southern Co. could add 9.3 GW.

Lower curtailment rates still could provide significant headroom, the study says, with PJM opening up 17.8 GW at 0.5% curtailment and 13.3 GW at 0.25% curtailment.

The length of curtailment periods also would vary, with a 1% curtailment lasting no more than 2.5 hours, while a 0.25% curtailment rate would last only 1.7 hours.

"These results suggest that the U.S. power system's existing headroom … is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year," the report says, framing flexibility as a win-win for all stakeholders.



The Duke University study shows the potential curtailment headroom flexible loads could provide, depending on the percentage of curtailment (left) and by individual RTOs, ISOs and utilities (right). | *Nicholas Institute, Duke University*

The U.S. still will need to build new generation and transmission to meet anticipated demand growth, the report says. "[But] flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion and enable greater focus on the highest-value investments in the electric power system."

"The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably and sustainably integrate large loads," the report says. "The unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources."

Data Centers and DR

Authored by researchers at Duke's Nicholas Institute for Energy, Environment and Sustainability, the study grounds its argument for flexibility in the current flashpoints for demand growth. Data centers often have aggressive schedules for going online but may face yearslong interconnection and supply chain delays.

Lead times for ordering transformers have gone from less than a year to two to five years, with prices rising 80%, according to June 2024 figures from the president's National Infrastructure Advisory Council, the report says. Wood Mackenzie has reported that lead times for high-voltage circuit breakers were nearing three years at the end of 2023.

The report notes the growing interest in co-locating data centers with existing or new generation, but says it is not likely to be "a long-term, systemwide solution."

The fact the U.S. grid is designed with headroom to accommodate relatively short periods of peak demand and often is underused provides a further rationale for leveraging this built-in flexibility, the report says. Better use of the system can reduce costs for consumers by "lowering the per-unit cost of electricity — and [reducing] the likelihood that expensive new peaking plants or network expansions may be needed."

The report notes that some grid operators and utilities already are experimenting with flexible interconnection strategies, such as ERCOT's interim treatment of new large loads as "controllable" resources, allowing them to go online in less than two years.

Still another argument for flexibility is the recent release of DeepSeek, the Chinese AI platform that claims to use significantly less energy than U.S. AI. Here, the report says, system flexibility could serve as a hedge for potential demand uncertainty.

But getting data centers to participate in traditional demand response programs — which have long provided system flexibility — has been difficult because of centers' often inflexible, 24/7 demand profiles. Further, traditional DR programs have been designed for "traditional industrial consumers … with different incentives and operational specifications." The report suggests new programs should be developed to align with data centers' needs, including "streamlined participation structures, tailored incentives and metrics that reflect the scale and responsiveness of data centers."

New AI data centers, with "evolving computational loads … are more amenable to load flexibility," the report says. The "training" of AI databases allows for flexible timing and the distribution of workloads across different data centers. An EPRI report cited by the Duke researchers found that "optimizing data center computation and geographic location … to capitalize on lower electric rates during off-peak hours" could provide cost savings of 15% and reduce strain on the grid during high-demand hours.

The report points to three trends that could "create further opportunities for load flexibility now than in the past." First is the construction and interconnection delays that increase costs and timelines for getting new centers online, followed by the growth of clean, distributed technologies that offer lower-cost, behind-the-meter generation.

The third is the growth of hyperscale data centers and their computational loads, "which is lending scale and specialization to more sophisticated data center operators," the report says. "These operators, seeking speed to market, may be more likely to adopt flexibility in return for faster interconnection." ■

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Duke Paper Lays out How FERC Can Make Flexibility for Large Loads Reality

DOE Reliability Report Argues Changes are Required to Avoid Outages Past 2030

By James Downing | Originally Published 7/7/25

The U.S. Department of Energy released a report July 7 saying that retirements and delays in new firm capacity "will lead to a surge in power outages and a growing mismatch between electricity demand and supply," especially from growth driven by data centers.

The Report on Evaluating U.S. Grid Reliability and Security responds to President Trump's executive order from April, which DOE used to keep open power plants in MISO and PJM that were set to retire in May. Trump's order directed DOE to come up with a uniform method of studying resource adequacy. (See *Trump Seeks to Keep Coal Plants Open, Attacks State Climate Policies*.)

"This report affirms what we already know: The United States cannot afford to continue down the unstable and dangerous path of energy subtraction previous leaders pursued, forcing the closure of baseload power sources like coal and natural gas," Energy Secretary Chris Wright said in a statement. "In the coming years, America's reindustrialization and the AI race will require a significantly larger supply of around-the-clock, reliable and uninterrupted power.

The report argues that "absent decisive intervention," the grid will be unable to meet projected demand for manufacturing, re-industrialization and data centers, which make adversary nations control the future development of artificial intelligence, thus jeopardizing economic and national security.

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The status quo of additional generator retirements and "less dependable replacement generation" is not consistent with winning the AI race or maintaining reliability, the report said. "Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens."

The report estimates an additional 104 GW are set for retirement by 2030, which is planned to be replaced by 209 GW, though only 22 GW of that is from "baseload sources." Retirements and load growth combined could lead to 100 times greater risk in power outages by the end of the decade, the report said.

"Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids," the report said. "At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids."

The report said it used a model based on NERC's Interregional Transfer Capability Study, which uses time-correlated generation and outages based on historical data. It looked at a range of projections for data center demand by 2030 from major projects and picked a midpoint of 50 GW, allocating it regionally based on a forecast from Standard & Poor's.

The report includes several models, including one with the 104 GW of retirements that are in line with NERC and Energy Information Administration projections, another without power plant closures and a scenario with replacement capacity.

The only regions that did not fail to meet reliability thresholds in the power plant retirement category were ISO-NE and NYISO, which are not expected to see additional data center growth. But every other region saw higher risks of outages in the closed power plant case. Even if all the power plants were to stay open, the report still found shortfalls in PJM, SPP and the Southeastern Electric Reliability Council.

The report found that at least 23 GW of new "perfect capacity" is needed to meet future demand, especially in ERCOT and PJM (particularly in Virginia and Maryland).

The report calculates unserved energy (USE) for different regions of the country based on its forecast supply and demand and found troublingly high levels of the metric in some regions for 2030.

"It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system," the report said. "Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need."

The report does not use common probabilistic measurements of resource, such as expected unserved energy (EUE) or loss of load expectation (LOLE), instead using deterministic equivalents.

The report was released midafternoon July 7, so most people had limited time to review it. Advanced Energy United Managing Director Caitlin Marquis said it appears to exaggerate the risk of blackouts and undervalues the reliability contributions of wind, solar and battery storage.

"We are working quickly to dig into the numbers to unpack how DOE reached its conclusions, but it's troubling that the report was not subject to public input and scrutiny, especially since the executive order that mandated it calls for it to be used to identify power plants that should be retained for reliability," Marquis said in a statement. "If the analysis is overly pessimistic about advanced energy technologies and the future of the grid, consumers will end up paying too much for resources we no longer need." ■

Plan Lays out Steps for State-led Interregional Transmission in Northeast

Brattle Plan Seeks to Create the 'Missing Middle' in Transmission Development

By Vincent Gabrielle | Originally Published 4/28/25

The Northeast States Collaborative on Interregional Transmission released a *strategic action plan* April 28 for creating an interstate planning process for transmission projects that span the seams of their grid operators.

The collaborative comprises nine states — Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island and Vermont — and was formed with the goal of exploring "opportunities for increased interconnectivity" between ISO-NE, NYISO and PJM. (See *10 Northeastern States Sign MOU on Interregional Transmission Planning*.) (New Hampshire signed the initial memorandum of understanding creating the group but did not sign on to the plan.)

The plan, prepared by The Brattle Group, goes further than exploration and into concrete steps for soliciting projects and proposing them to the grid operators. It implicitly criticizes FERC's planning rules, including the recent Order 1920, for creating barriers to interregional projects.

"No process currently exists for groups of states spanning different transmission planning regions to take the various steps necessary to identify, evaluate, select and agree to share the cost of beneficial interregional transmission projects so they can be developed," the plan says. "Members of the collaborative have referred to the absence of such a process as 'the missing middle.'"

Brattle focused on what states can do in the short term — including over the next year — to identify beneficial interregional projects and "make them actionable through existing regional planning processes." Such projects would help states reach not just their long-term emission-reduction goals but also address their looming resource adequacy concerns.

"New York is pleased to be a part of this strategic partnership so that together with our fellow Northeast states, we can find more effective and affordable solutions to maximizing transmission opportunities that can both provide increased reliability as well as deliver additional clean energy to our grid," New York State Energy Research and Development Authority President Doreen Harris said in a statement.

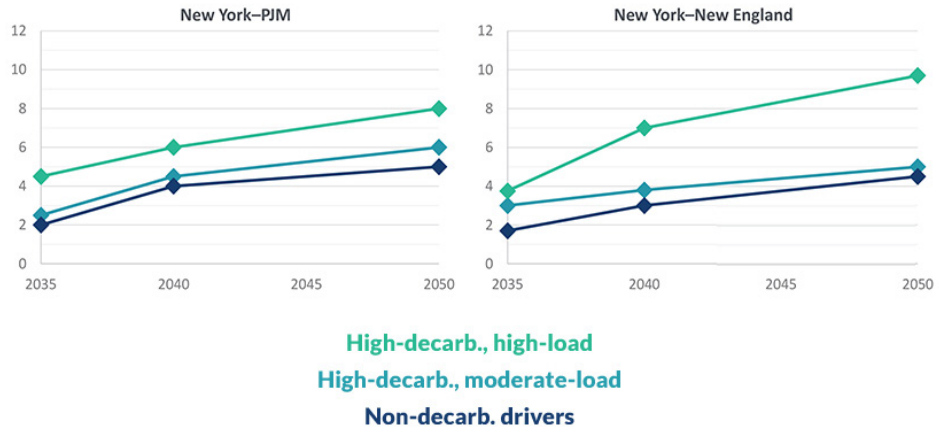
Over the next year, the states will attempt to identify "low-hanging fruit" projects through a request for information. Brattle recommends the states ask the three grid operators to take on advisory roles in the process, as any project will need to be integrated into each of their transmission plans. It also suggests including NERC, "given its recent identification of interregional transmission solutions as necessary to ensure a reliable electric grid." (See *NERC Responds to Interregional Transfer Capability Study Comments*.)

Simultaneously, Brattle says, the states should consult with the grid operators and FERC on what, if any, tariff changes would be necessary to facilitate the interstate process.

The plan also includes goals for the end of 2027, including the development of HVDC design standards to facilitate an offshore transmission network and joint offshore wind procurements.

"Not having to build new power plants saves Marylanders money," Maryland Energy Administration Director Paul Pinsky said. "Increased regional transmission capacity can reduce the need for power plants that solely exist to meet peak demand, which are typically fossil fueled. … This collaboration illustrates why state-led climate action is so important to achieving our energy, environmental and economic goals."

"States across the Northeast share a common priority to ensure an affordable, reliable and sustainable electric grid," Vermont Department of Public Service Commissioner Kerrick Johnson said. "Transmission is at the heart of securing that energy future." ■



Estimated range of low-regrets transmission expansion needs (GW) | *The Brattle Group*

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Energy Innovation: US Needs New Approach to Grid Reliability

Renewables, Demand-side Resources Cheapest, Fastest Answer to Demand Growth

By K Kaufmann | Originally Published 2/18/25

To build a reliable, affordable and clean electric power system that can meet the challenges of unprecedented demand growth, the U.S. energy industry and the customers it serves will need to shift their thinking about what a reliable system looks like, according to a *new study* from nonprofit think tank Energy Innovation Policy & Technology.

"Grid operators, reliability authorities and utilities are ringing reliability alarm bells, and outdated views on grid reliability are colliding with slow-moving institutions," the report says. New concepts of reliability are needed so that "utilities and grid operators can build new generation faster and more efficiently, while simultaneously deploying strategic demand-side solutions at scale."

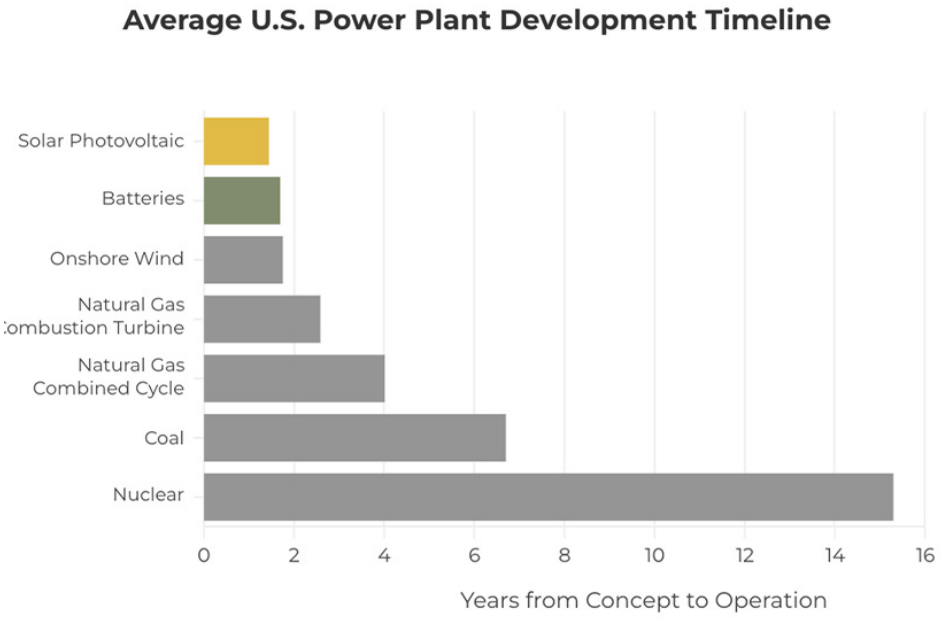
In opposition to President Donald Trump's call to ensure reliability by building new fossil fuel-fired plants, Energy Innovation argues that "reliability is a characteristic of the whole electric system, to which individual resources contribute. Every source of electricity has different characteristics that should complement each other in a balanced portfolio."

Examples include the increasing number of grids around the world that provide reliable service with major amounts of solar, wind and storage online, it says.

"For instance, large grids in the Midwest, Texas and California regularly operate using more than 70% renewable energy, and … Iowa and South Dakota generated roughly 60% of all their electricity in 2023 from wind power," the report says. "In Hawaii, South Australia and Denmark, grids are already operating using 100% renewable power for days at a time.

"Notably, though, these jurisdictions have adjusted their planning and operating practices to integrate higher penetrations of renewable energy and battery storage without compromising reliability."

The Energy Innovation report is intended to be a primer for U.S. regulators and policymakers to demystify the often-daunting technical details of "grounding reliability discussions in meaningful solutions … while also discussing the challenges in achieving a 100% clean electricity grid."



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Caught between the high speed of data center buildout and the much slower regulatory speed of project permitting and interconnection, the industry is at "an inflection point where the pressures are growing," Sara Baldwin, Energy Innovation's senior director of electrification policy and co-author of the report, said in an interview with *RTO Insider*. "So, the lag that is created in slow decision-making is actually exacerbating the challenges. It's creating more of an energy emergency. … Excuses are standing in the way.

"We're actually not confronting technical challenges as much as we're confronting human challenges," Baldwin said. "And in some ways, human challenges are harder because human beings want to have full control over all the decision-making that falls underneath their jurisdiction and in their purview."

An example is the traditional thinking about the need for system inertia, provided by spinning turbines and typically powered by fossil fuels or hydropower, often cited by industry leaders arguing for more baseload power.

Specifically, they say, inertia can help to keep frequency levels on the grid stable in the event of stress on the system or disturbances caused by extreme weather.

Report co-author Michelle Solomon, En-

ergy Innovation's manager for electricity policy, countered that "traditional inertia isn't actually something that you need to run the grid. Traditional inertia is part of this broader frequency response set of services, and actually, in many cases, inverter-based resources can respond faster … and provide what's called synthetic inertia."

The report notes that "while inertia slows frequency decline, it is not capable of restoring frequency back to its nominal level. Instead, services like fast frequency response, which can both slow the rate of frequency decline and help restore frequency are needed. …

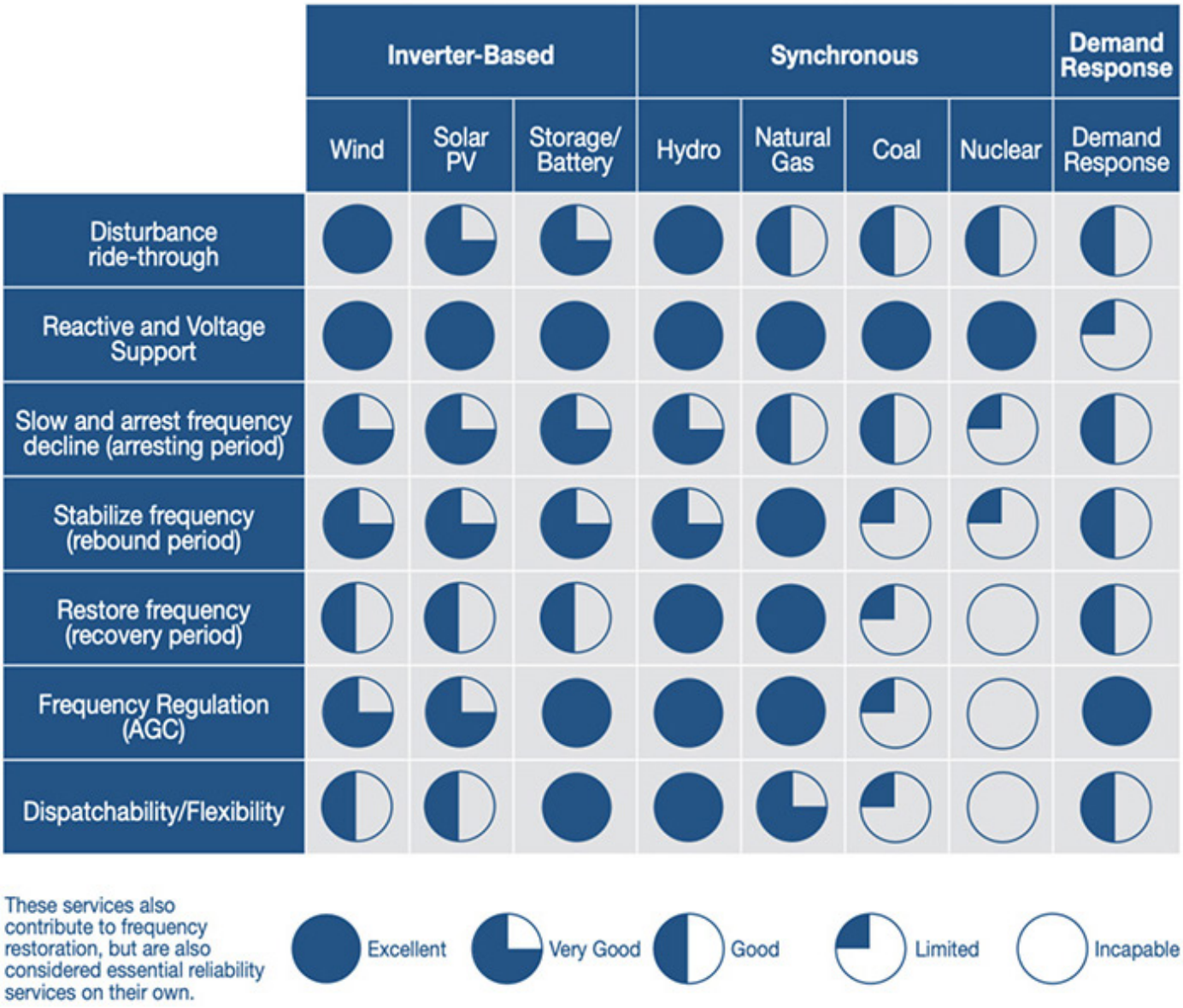
"Inverter-based resources (IBRs) can ramp up and down much more quickly than a conventional power plant, making them more responsive to changing grid conditions," the report says. "IBRs can provide nearly instantaneous fast frequency response."

Can IBRs Deliver?

But the report also acknowledges that a significant gap exists between what IBRs are technically capable of doing and industry confidence in their ability to deliver when needed in real-life situations.

"Developers must be disciplined to program their resources to ride through a voltage event [even] if such a setting should compromise their asset or their operating revenues," the report says. Similarly, utilities and grid operators need to "quantify and understand how IBRs respond during a grid emergency" and ensure appropriate compensation in cases where they "provide a superior response."

For Mark Lauby, senior vice president and chief engineer at NERC, such recommendations contain a lot of "ifs" and potential threats to reliability. While he agreed that the future of the U.S. grid lies in a portfolio of diverse resources, including IBRs, "they haven't been proven. We haven't



Grid services provided by inverter-based and synchronous resources | *Milligan Grid Solutions*

got a lot of them on the system."

New and traditional technologies have "got to work together, not against each other," Lauby said in an interview with *RTO Insider*.

"Batteries can move very quickly as long as they are charged … and inverter-based resources can mimic some of the things like inertia on the system, but they have got to be able to run on the battery," he said. "The battery better be charged, and if you have long-term events, where you've kind of exhausted your battery storage, now you don't have energy and, by the way, you don't have essential livelihood services."

Lauby also said that while management of demand-side resources can be effective for shaving peak demand, which can be predicted and prepared for, stress on the grid is now coming at less predictable times and locations.

IBRs could build more uncertainty into electric systems, on top of the essential variability of wind and solar, he said. For example, a dayslong drop in wind could take thousands of megawatts off the grid.

NERC is working on a range of standards intended to build industry confidence in the reliability of IBRs and other new technologies, he said.

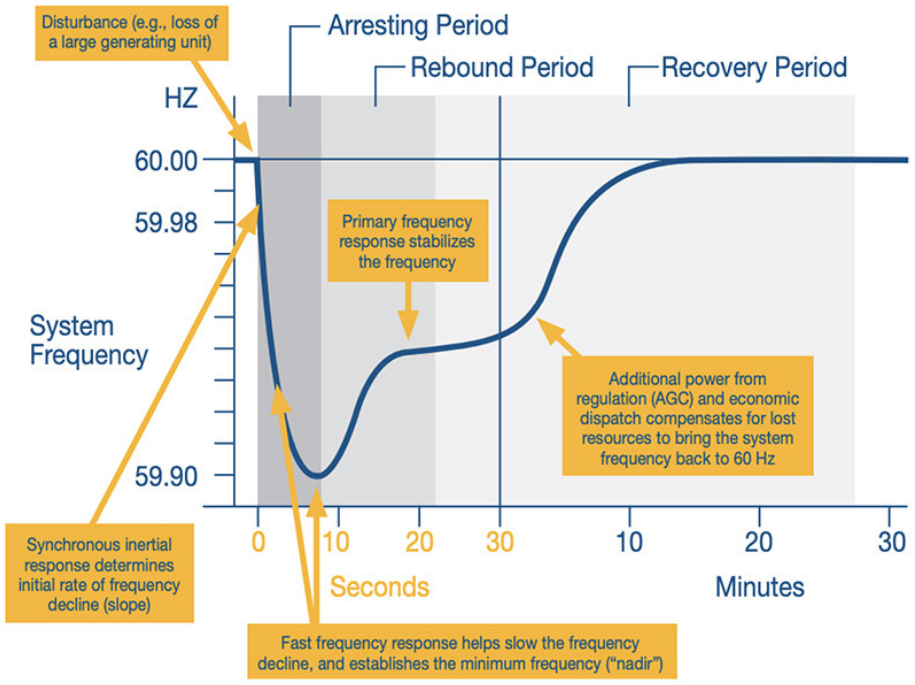
Natural Gas Won't

The Energy Innovation report comes at a pivotal moment in industry and public debates over the most effective short-term strategies for meeting data centers' ravenous appetite for electricity, which could make up 12% of U.S. energy demand by 2028. (See *Berkeley Lab: Data Centers Could Need 12% of US Power by 2028*.)

The Trump administration and congressional Republicans are advocating for regulatory changes to allow faster permitting, interconnection and construction of natural gas plants, which they are promoting as baseload power that will keep the lights on and cut consumers' bills.

For example, in a *speech* on the House floor Feb. 13, Rep. Julie Fedorchak (R-N.D.) announced her plans to form an AI and Energy Working Group that would target increasing baseload power on the grid.

"The rapid, forced transition to intermittent power sources — paired with the retirement of reliable baseload generators — has left our electric grid increasingly vulnerable to outages," Fedorchak said.



An illustrative example of grid services working together to stabilize frequency | *Milligan Grid Solutions*

On Feb. 11, FERC approved PJM's Reliability Resource Initiative, a one-time measure aimed at adding extra capacity to the RTO's system by allowing generation that meets certain criteria to essentially jump its notoriously backlogged interconnection queue. (See *FERC Approves PJM's One-time Fast-track Interconnection Process*.)

Renewable developers opposed the initiative, saying it is designed to allow large natural gas plants to get online ahead of the approximately *286 GW* of projects, mostly wind, solar and storage, that have been waiting for years for PJM to work through its queue backlog.

On the other side, the Solar Energy Industries Association has been attempting to pivot the public dialogue on demand growth to include solar, storage and other renewables as "the fastest technologies to develop and deploy. Not only are they much simpler to engineer, their supply chains are more robust than natural gas (which currently faces a bottleneck in gas turbine blades)," SEIA said in a Feb. 4 *blog post*. Natural gas plants can also be 2.5 times more expensive to build, it said.

The Energy Innovation report joins a recent study from Duke University in arguing for aggressive deployment of demand-side resources that can open up capacity on the grid versus inherently slow and costly fossil fuel generation. (See *US Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

"While strategic new generation and transmission solutions are needed to meet growing demand, these large investments will show up on customers' electric bills for decades to come and could increase emissions without helping affordability or sufficiently improving reliability," the report says.

"But aggressive investments in demand-side solutions are a cost-effective, least-regrets way to manage growth in the near term, while unlocking their full potential over the long term." Similarly, getting solar, wind and storage online quickly will buy time for the development of dispatchable, zero-carbon generation that could replace fossil fuels, the report says.

Pointing to the 2,600 GW of mostly renewable projects in RTO and ISO interconnection queues, Solomon said, "Because wind and solar and batteries are already in the process of being built, [they] can come online in a matter of a year and a half. … The gas plants they are looking at building are not coming online until 2030. Natural gas isn't the solution that's going to deliver." ■

NYPA Files Petition with New York PSC to Save Clean Path Project

By Vincent Gabrielle | Originally Published 1/6/25

The New York Power Authority on Dec. 23 filed a *petition* with the Public Service Commission asking it to designate Clean Path NY as a Priority Transmission Project (PTP) under the Accelerated Renewable Energy Growth and Community Benefit Act.

The $11 billion Clean Path's renewable energy certificate between the developers and the New York State Energy Research and Development Authority was terminated in November. (See *$11B Transmission + Generation Plan Canceled in NY*.) The project is a public-private collaboration of NYPA and Forward Power, which is a joint venture of energyRe and Invenergy.

It would consist of 178 miles of HVDC line between Delaware County and Queens to bring 3.8 GW from 23 new solar and onshore wind projects to New York City. The line is engineered to be bidirectional so that offshore wind could serve upstate load when needed.

The November announcement led many to assume the project was effectively dead. But "it's important to remember that a NYSERDA contract cancellation does not equal a project cancellation," wrote Marguerite Wells, president of the Alliance for Clean Energy New York. "As we saw with many clean energy generation projects over the last couple of years, developers continued advancing projects after a contract cancellation, and many of them have since secured new contracts. This filing shows that the idea and development of Clean Path continues."

PTPs are projects deemed necessary on an "expeditious" basis to access and deliver renewable energy resources, and they are referred to NYPA exclusively for development.

"Expedited development of the Clean Path transmission project is critical to advancing the state's achievement of the aggressive" mandates of the Climate Leadership and Community Protection Act (CLCPA), NYPA wrote in its petition.

But PTP designation would not save the entire project. The NYSERDA contract included the 23 new renewable facilities.

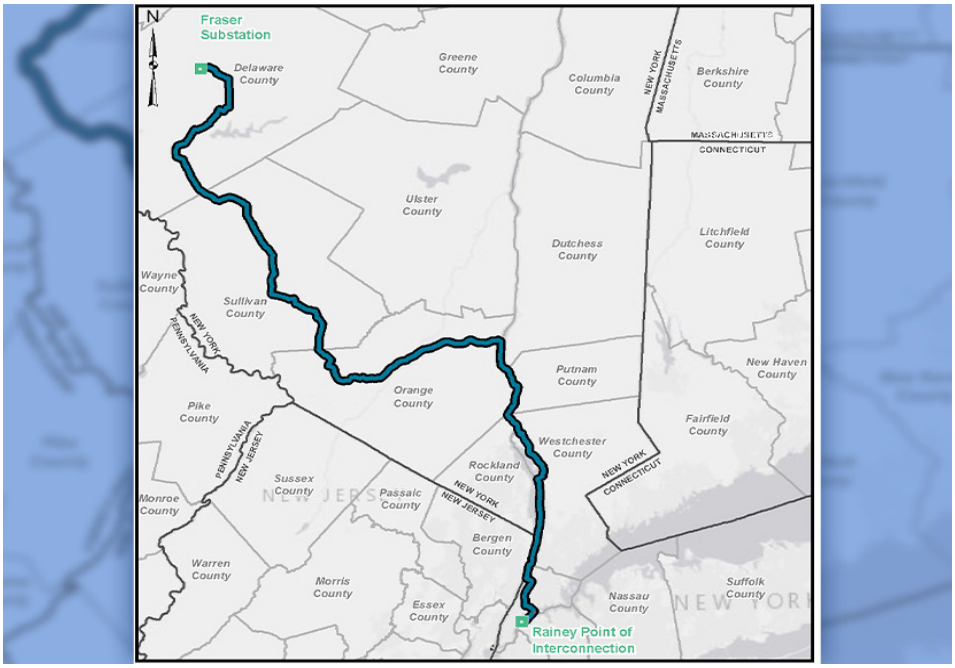
"Our proposal would accelerate development and address the state's need to transmit upstate renewable energy directly into New York City, reducing congestion to support the decarbonization of the electric system in line with the state's climate goals," NYPA spokesperson Lindsay Kryzak said in a statement. "NYPA awaits a decision on its petition by the PSC."

NYPA estimated that the project would reduce emissions and produce cost savings to ratepayers both in terms of capacity payments and congestion payments to the tune of about $6.2 billion over a 23-year period. This would help the state meet its climate goals by increasing the availability of renewable energy downstate while bypassing the relatively slow project planning processes of NYISO and the PSC, it said. It also argued that a new project would not be selected until mid-2027 at the earliest, delaying the in-service date until after 2030.

NYPA estimated that it can complete the project before 2030 if the petition is approved. It cited many planning and interconnection hurdles that are already finished or well in progress, including federal applications, NYISO interconnection studies and pre-secured fabrication slots with cable manufacturers.

It also cited NYISO's most recent Reliability Needs Assessment that found a reliability need in New York City starting in 2033. Furthermore, NYISO estimates that by *2030* the system will transition from a summer peak to a winter peak.

The Champlain Hudson Power Express line, which will inject hydropower from Quebec to the city, should be in-service by then but is not *obligated* to deliver electricity to New York during the winter. 2030 is also the deadline for meeting some of the emissions targets of the CLCPA. ■



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DOE Official to NASEO: 'There is not an Energy Transition'

Energy Sec. Wright Drops U.S. Net-zero Goal, Calls for 'Nuclear Renaissance'

By K Kaufmann | Originally Published 2/6/25

WASHINGTON, D.C. — "The Trump administration will have a 180-degree opposite view of energy and climate issues than the previous administration," Lou Hrkman, acting assistant secretary at the U.S. Department of Energy, told the opening session at the National Association of State Energy Officials' Energy Policy Outlook Conference on Feb. 5.

And he added, "From my standpoint, thank goodness!"

Hrkman served as DOE deputy assistant secretary for advanced energy systems and carbon management in the first Trump administration, and this time around is heading the Office of Energy Efficiency and Renewable Energy. Facing a ballroom full of state energy officials, he outlined what that policy U-turn will mean with newly confirmed Energy Secretary Chris Wright, a fossil fuel executive, leading the department.

Hrkman agrees with his new boss's much-publicized view that "there is not an energy transition." Citing figures from the U.S. Energy Information Administration, Hrkman said that by 2050, "fossil fuels will continue to provide 80 to 85% of energy use worldwide, just about the same percentage as it is now. Renewables are additive; they are not replacing fossil fuels."

He also endorsed Wright's belief that "climate change [is] a challenge, but ending world energy poverty is a more important goal."

Lou Hrkman, DOE acting assistant secretary for energy efficiency and renewable energy, speaks at the NASEO Energy Policy Outlook Conference on Feb. 5. | *© RTO Insider*

Hrkman's remarks received respectful, if not enthusiastic applause from an audience of state officials who are now waiting to see if they will receive the billions in federal dollars they were awarded for a range of clean energy projects funded through the Inflation Reduction Act and Infrastructure Investment and Jobs Act.

The Office of Management and Budget issued and then quickly rescinded a funding freeze days before the NASEO event, followed by a *restraining order* issued by the U.S. District Court in D.C. Still, ongoing uncertainty provided the background buzz at the conference. (See *Judge Issues Restraining Order on Trump Admin over Funding Pause*.)

"There's a lot of angst at the state level, and that's red, blue and purple across the board," said California Energy Commissioner Andrew McAllister, a past president of NASEO. "These monies, many of them, have been contracted already. They're obligated. We have contractors ready to spend the money, in some cases, already spending the money and putting programs together and pushing out rebates to American citizens. And so, I think it's a shame if that stops."

While not mentioning solar, wind or storage, Hrkman called for a "best-of-the-above" approach, which puts fossil fuels first as critical to "American civilization. … There is no analysis by any credible source or government organization that concludes net zero will be achieved by 2050; not here in the U.S., not in your states, not anywhere in the world."

"Net zero can only be achieved when technology advances," he said. "Over time it is accepted by the public. The new technology is affordable, and market forces, not government mandates lead the way." A similar time-and-technology approach will eventually bring down greenhouse gas emissions, he said.

The technologies DOE will prioritize going forward, besides fossil fuels, will be nuclear, geothermal and fusion energy, he said, while building out supply chains for critical mineral mining and refining.

He also signaled a rollback of energy efficiency standards for home appliances set by Biden's DOE, arguing that consumer choice and commonsense goals would provide "real energy savings, [and] dollars in real pockets for real consumers."

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Republicans Celebrate Changed Energy Policy at AFPI Summit

Livewire: Why Chris Wright is So Wrong

On permitting reform, Hrkman said it is "desperately" needed but should not be used "as a smoke screen to allow socialized costs of new transmission for renewable energy sources. Ratepayers in the states and cities that use that energy should pay the full cost for transmission, just like it is today."

Political Rhetoric, Physical Reality

On his first day in office on Feb. 5, Wright backed up Hrkman with a series of *orders* aimed at implementing President Donald Trump's Jan. 20 executive order on *Unleashing American Energy*, beginning with a blanket refutation of cutting greenhouse gas emissions to net zero as a long-term U.S. goal.

Calling net zero too expensive and ineffective in cutting emissions, Wright said, "going forward, the department's goal will be to unleash the great abundance of American energy required to power modern life and to achieve a durable state of American energy dominance."

He also pledged a thorough review of DOE's research and development activities to prioritize "true technological breakthroughs — such as nuclear fusion, high-performance computing, quantum computing and AI — to maintain America's global competitiveness. …

"The long-awaited American nuclear renaissance must launch during President Trump's administration," he said. "The department will work diligently and creatively to enable the rapid deployment and export of next-generation nuclear technology."

Other priorities include refilling the U.S. Strategic Petroleum Reserve; developing more baseload, dispatchable resources to improve grid security; and, of course, permitting reform.

Arguing against Trump's attack on clean energy and climate action, Rep. Doris Matsui (D-Calif.) countered that "our energy system and climate change are inextricably linked. Many people want to pretend climate change isn't happening. The physical reality doesn't bend to political rhetoric.

"We must reduce emissions as quickly and rapidly as possible while still improving grid reliability, reducing energy costs and meeting increasing energy demands."

Matsui called the challenges ahead "a perfect storm, unlike anything we faced before," urging state officials to "get serious about working together."

"We must chart a path forward that is both forward-looking and feasible," she said. "We are not on that path. Banning wind energy, blocking solar on federal lands, tariffs on energy imports and critical grid equipment, this is not going to make energy cheaper. This is not going to make energy more abundant or more reliable."

Grid-enhancing technologies and demand flexibility provided by distributed energy technologies such as virtual power plants should not be partisan issues, she said.

"It's common sense that we need more capacity to transfer energy where it's needed most," she said. "We should embrace a more flexible, more dynamic energy paradigm."

Echoing Matsui, McAllister said states will have to work with the federal government and compromise will be key.

Hrkman's speech provided some clarity for state officials at the conference, McAllister said. "We're just hearing exactly what we needed to hear and to understand the directions the new administration is proposing."

While California has the resources to ride out a funding pause and keep some of its IRA-funded clean energy projects "on life support" at least for a while, McAllister acknowledged that other states might not have the same options.

He sees the federal focus on reliability, affordability, jobs and economic development as a starting point where federal and state energy officials might work together. "There's plenty of palette for us to paint with," he said.

"When the smoke clears and we figure out what the actual, sort of substantive daily priorities are going to be for the staff at the Department of Energy, and what initiatives they're actually going to be working on — I don't really want to speculate — but I feel like there's a lot that we can do together, and I hope that we do." ■

DOE Terminates $7.56B in Energy Grants for Projects in Blue States

West Coast Hydrogen Hubs, MISO-SPP Transmission Portfolio Among the Targets

By John Cropley and Tom Kleckner | Originally Published 10/2/25

The U.S. Department of Energy has terminated 321 grants totaling $7.56 billion for 223 projects, apparently targeting Democratic-leaning states.

The *Oct. 2 DOE announcement* did not specify the grants being eliminated, but later in the day, Democrats on the House Appropriations Committee *posted the list*. They said the projects are in 108 congressional districts represented by Democrats and 28 represented by Republicans.

Russell Vought, director of the Office of Management and Budget, *posted on X* on Oct. 1 that the cuts were being made to "Green New Scam funding" for projects that are part of the "Left's climate agenda." The 16 states he identified were won by former Vice President Kamala Harris in her losing run against President Donald Trump in 2024.

The 32 U.S. senators representing those 16 states are all Democrats and all voted against a bill that would have averted the federal government shutdown.

But the grant cancellations will have some fallout in red states as well.

MISO-SPP Portfolio

Among the terminated financial awards, the fifth largest is the $464 million grant for the MISO-SPP Joint Targeted Interconnection Queue (JTIQ) portfolio under DOE's Grid Resilience and Innovation Partnerships (GRIP) program.

The grant was intended to offset about 25% of the projected $1.6 billion capital costs for the JTIQ portfolio's five 345-kV projects. The funds were *awarded in 2023* to the Minnesota Department of Commerce, the lead applicant in a project that also involves the Great Plains Institute and the two RTOs. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

A Commerce Department spokesperson said the department has not received "any formal notification" from DOE on the GRIP funding's termination. However, it was included in the list distributed by House Democrats.

In a statement provided to *RTO Insider*, the Commerce Department said it was "deeply concerned" about DOE's suggestion of an "illegal effort to rescind federally obligated energy funds targeted exclusively at blue states."

"If true, this would represent an unprecedented and politically motivated breach of federal law and funding norms — with potentially serious consequences for families, businesses and communities across Minnesota," it said. "Without these investments, Minnesota could face higher energy prices, slower infrastructure development, and increased burdens on low- and middle-income households — all while demand for clean, affordable energy continues to grow."

While Minnesota has been coordinating the application process and is responsible for the granted funds, the JTIQ's proposed projects are sited in the Dakotas, Iowa, Kansas, Missouri and Nebraska, all of which lean heavily Republican.

The grid operators have said the "backbone" projects will unlock 28 GW of capacity and reduce curtailments in the highly congested region along their seam. FERC has approved and reaffirmed the RTOs' proposal to fully allocate the costs of the JTIQ portfolio to interconnecting generation assessed per megawatt. (See *FERC Upholds MISO and SPP's JTIQ Cost Allocation over Criticism*.)

"Federal energy funding plays a vital role in expanding clean energy generation, providing reliable energy transmission [and] creating jobs," Commerce said. "This kind of action directly undermines [DOE's] stated priorities: ensuring energy abundance and maintaining affordability for Americans."

Commerce said it is working with state and federal partners to "assess" the situation and protect Minnesota's interests.

An SPP spokesperson said it is working with Commerce and MISO to "review the order and consider options."

MISO said it is monitoring the "developing situation" and that it will coordinate with its project partners "to understand any potential impacts."

The project's partners have 30 days to appeal the termination; DOE said some award recipients already have begun that process.

DOE *said* in May it was reviewing the "billions of dollars that were rushed out the door" in the Biden administration's final days. It requested additional information to evaluate 179 awards covering more than $15 billion in financial assistance. (See *MISO-SPP JTIQ Fed Funds Caught Up in DOE Review of Grants*.)

The largest cuts were to the Biden administration's Hydrogen Hub initiative. California stands to lose $1.2 billion promised to its $10 billion-plus ARCHES hydrogen initiative, while the Pacific Northwest Hydrogen Hub stands to lose $1 billion.

The *CEO and board chair* of ARCHES called the decision short-sighted but said the initiative would go on without federal funding.

California Gov. Gavin Newsom (D) *went on the attack*: "In Trump's America, energy policy is set by the highest bidder, economics and common sense be damned."

Protest and Praise

"Following a thorough, individualized financial review, DOE determined that

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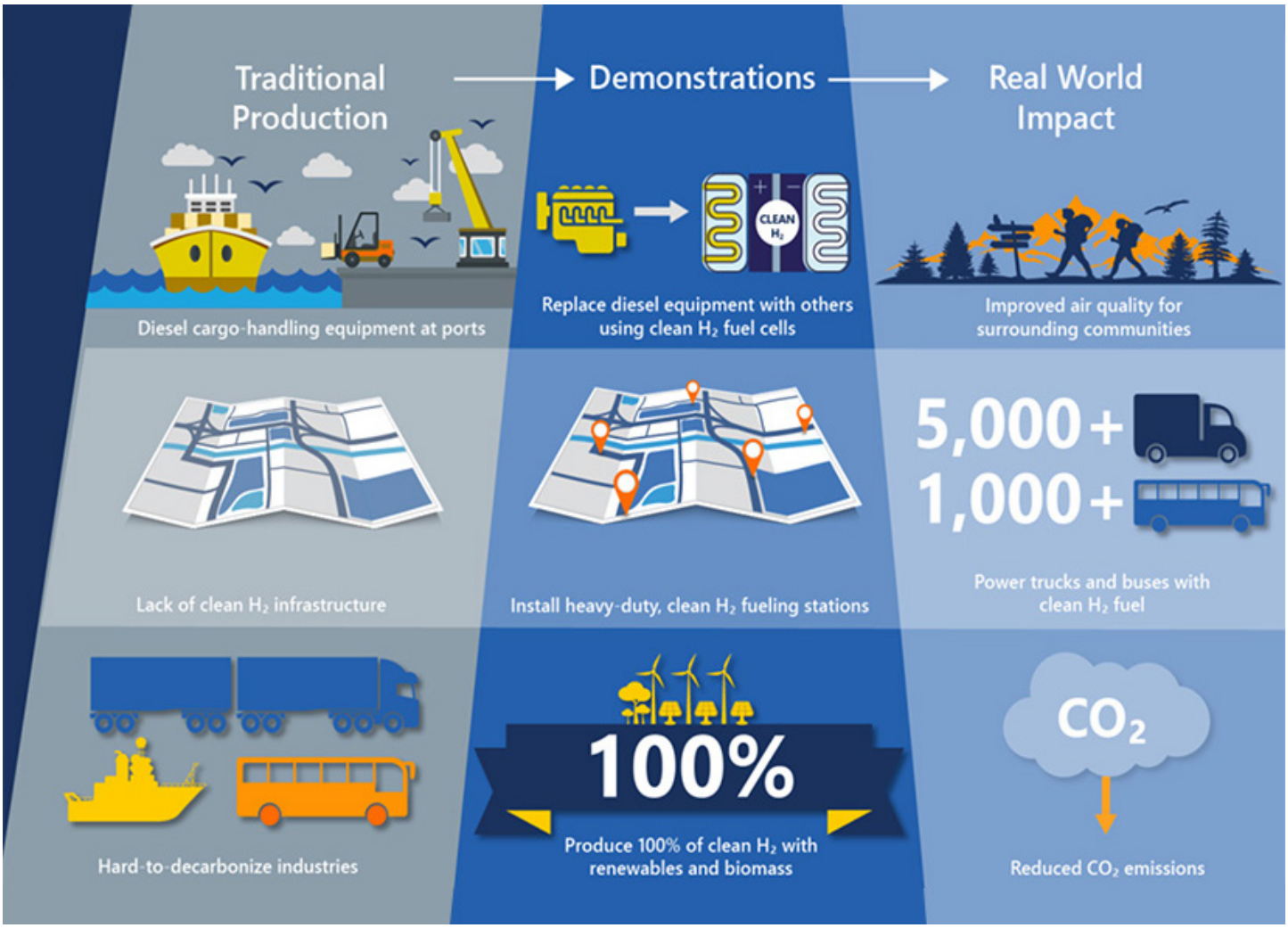

The U.S. Department of Energy is rescinding its $1.2 billion investment in ARCHES, the California Hydrogen Hub. | *DOE*

these projects did not adequately advance the nation's energy needs, were not economically viable and would not provide a positive return on investment of taxpayer dollars," the department said in a news release.

OMB's Vought identified the states hosting targeted projects as California, Colorado, Connecticut, Delaware, Hawaii, Illinois, Maryland, Massachusetts, Minnesota, New Hampshire, New Jersey, New Mexico, New York, Oregon, Vermont and Washington.

DOE said the grants being terminated had been awarded by its offices of Clean Energy Demonstrations, Energy Efficiency and Renewable Energy, Grid Deployment, Manufacturing and Energy Supply Chains, Advanced Research Projects Agency-Energy and Fossil Energy.

It said 26% of the terminated grants and 41% of the money were awarded between Election Day 2024 and Inauguration Day 2025.

Reaction to the announcement was swift.

U.S. Sen. Adam Schiff (D-Calif.), a frequent critic of Trump, *posted*: "Our democracy is badly broken when a president can illegally suspend projects for blue states in order to punish his political enemies."

U.S. Rep. Troy Nehls (R-Texas) *posted*: "Terrific news. Terminate the Green New SCAM."

U.S. Sen. Patty Murray (D-Wash.), vice chair of the Appropriations Committee, *said*: "President Trump has spent the year hurting families, killing jobs and raising people's costs, and now he and Russ Vought are gleefully using the shutdown they have caused as a pretext to inflict even more pain. … This administration has had plans in the works for months to cancel critical energy projects, and now, they are illegally taking action to kill jobs and raise people's energy bills."

In a *Truth Social post*, Trump suggested there is more to come: "I have a meeting today with Russ Vought, he of Project 2025 fame, to determine which of the many [Democratic] agencies, most of which are a political SCAM, he recommends to be cut, and whether or not those cuts will be temporary or permanent. I can't believe the Radical Left Democrats gave me this unprecedented opportunity. They are not stupid people, so maybe this is their way of wanting to, quietly and quickly, MAKE AMERICA GREAT AGAIN!"

U.S. Rep. Rosa DeLauro (D-Conn.), ranking member on the House Appropriations Committee, *said*: "This was obviously designed as a political attack by the White House targeting Democrats. But the sad reality is that Americans — the middle class, working class and vulnerable — who voted for both Democrats and Republicans will be hurt by this. This is divisive, it is petty, and unfortunately it is exactly what we have come to expect from President Trump and Russ Vought." ■

Trump Executive Order Targets Renewable Energy Tax Credits

By John Cropley | Originally Published 7/7/25

President Donald Trump issued an *executive order* July 7 targeting renewable energy tax credits as strongly as possible under the One Big Beautiful Bill Act.

The law accelerates to 2026 the phase-out of the large tax credits created by the Inflation Reduction Act of 2022 in line with Trump's strong opposition to renewables and support for fossil fuel. He signed it at a July 4 ceremony. (See related story, *Trump Signs Big Beautiful Bill into Law on Independence Day*.)

The order, "Ending Market Distorting Subsidies for Unreliable, Foreign-controlled Energy Sources," directs Treasury Secretary Scott Bessent to determine and then take all actions needed to terminate 45Y and 48E clean energy production and tax credits for wind and solar facilities.

The OBBBA specifies construction start dates and safe-harbor provisions for the remaining period of eligibility for these tax credits, and Trump's order directs that these rules not be circumvented by eligibility manipulation.

Trump also directed prompt implementation of the bill's enhanced restrictions on foreign entities of concern. And he directed Interior Secretary Doug Burgum to look for and eliminate any codified forms of preferential treatment for wind and solar over dispatchable energy sources.

A giant cross and wind turbines dominate the skyline along Route 66 in Groom, Texas. | *Shutterstock*

The reasons stated in a *White House fact sheet* are familiar speaking points for Trump and some of his Republican allies:

- Wind and solar are unreliable, denigrate the natural beauty of the American landscape and displace dispatchable energy, compromising the grid.
- Reliance on green subsidies threatens national security by making the U.S. dependent on supply chains controlled by foreign adversaries.
- Ending these massive taxpayer subsidies is vital to energy dominance, national security, economic growth and the fiscal health of the country.

Trump specifies that his order be implemented consistent with applicable laws. However, there may be some room for interpretation of the energy-related provisions of *the 870-page OBBBA*.

Investment analysis firm Jefferies in a note to clients earlier July 7 said the House Freedom Caucus sought a strict interpretation by the administration of the "beginning of construction" provisions during negotiations as a condition for support. It said the concern now is whether the Trump administration will attempt to "change the goal posts" for these safe harbor provisions.

The order directs the Interior and Treasury departments to report back within 45 days on their findings and the actions they have taken or planned. ■

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