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FERC Independence Likely Coming to an End with Christie's Exit

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Assuming the Trump White House wins at the Supreme Court, FERC and other independent agencies likely will see the same kind of wild policy swings when the presidency changes parties as has been seen at other agencies such as EPA and DOE.

CONTINUED ON P.5

Will Christie's FERC Tenure End in a Bang or a Whimper? (p.3)

FERC Chair Mark Christie Leaves Agency After One Last Dissent (p.7)

PJM

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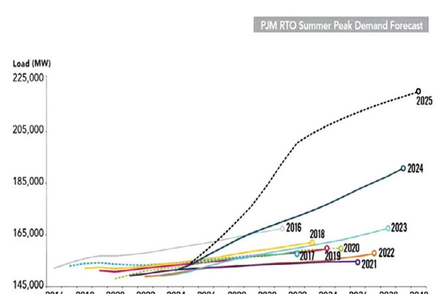
Pa., Va. Governors Float Clements, Christie as PJM Board Candidates (p.31)

Christie and Clements are the first candidates to be publicly named by any of the governors calling for a process for the states to nominate candidates to the PJM board.

PJM Board Initiates CIFP Addressing RA and Large Loads (p.32)

PJM Initiates Load Shed in Baltimore Region After Substation Disconnect (p.37)

PJM



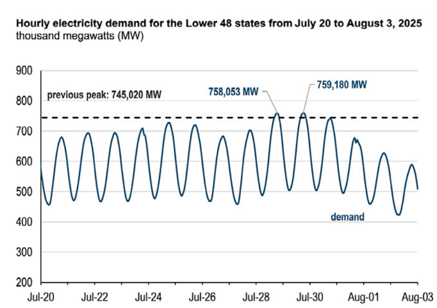
NJ BPU

N.J. Confronts Data Center Load Surge (p.33)

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.

PSEG Sees Data Centers Surge amid Rising Demand Forecasts (p.35)

FERC/FEDERAL | COMPANY NEWS



EIA

U.S. Peak Electricity Demand Sets Back-to-back Records (p.8)

Peak electricity demand in the Lower 48 set records twice in the last week of July, an extreme example of the increasing load being placed on the grid.

EPRI, Epoch AI Estimate Power Demands of Artificial Intelligence (p.15)

Google Strikes Demand Response Deals with I&M, TVA (p.57)

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RTO Insider
1877 Broadway #606
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In this week's issue

Will Christie's FERC Tenure End in a Bang or a Whimper?

By Paul Cicio

Paul Cicio

[EDITOR'S NOTE: This article was originally published online on Aug. 7, the day before FERC Chair Mark Christie resigned.]

FERC Chair Mark Christie's five-year term officially expired June 30, yet Senate gridlock over unrelated issues means President Trump's nominee, Laura Swett, is unlikely to be confirmed any time soon.

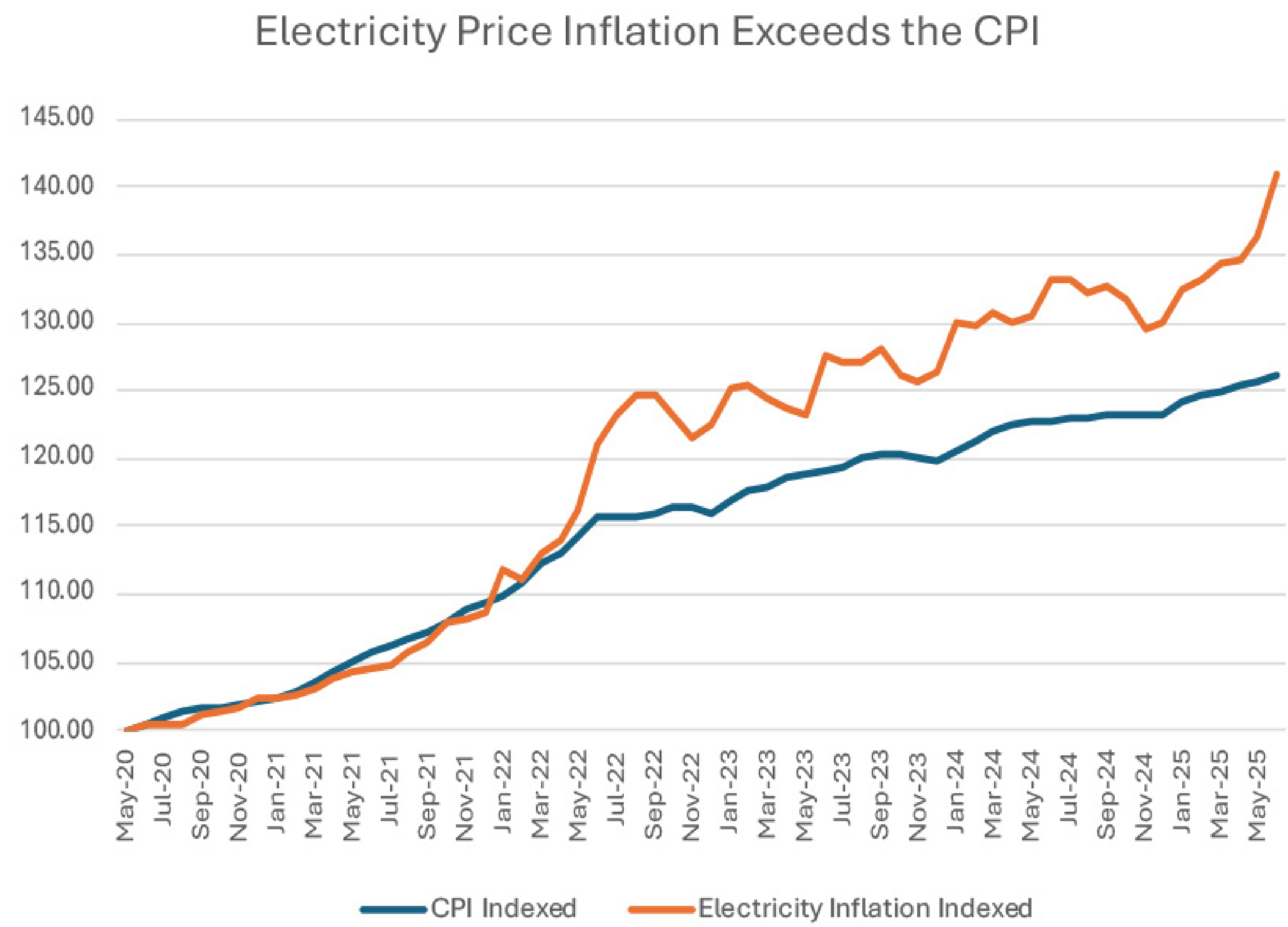
Christie, a vocal critic of high transmission costs and transmission incentives "candy" that impact every consumer in the nation, has only a couple of weeks to act to reduce consumer costs. The question is, will his tenure end in a bang or a whimper? He has the desire and intent, but will Commissioners Rosner, See and Chang follow his lead?

In his July 24 monthly meeting press conference, Christie said transmission costs are responsible for increasing electric rates being imposed on every consumer in the nation. Electricity prices are escalating nationwide despite the fact that until recently, demand has been flat. Each year for the past 10 years or so, monopoly utilities have spent billions of dollars per year on transmission and less than 10 percent of these transmission projects were competitively bid, which would have reduced consumer costs.

Economists frequently comment on rising inflation but miss the fact that electricity prices, which typically are stripped out of core inflation measurements, have consistently exceeded the consumer price index. The consistency of these price increases goes back longer than the AI-driven data center boom, and other inflationary factors. It is a price response to a policy problem: a lack of competition.

PJM, the largest RTO in the country, is a cautionary tale. In 2014, transmission charges were 6.8% of the PJM wholesale price. A decade later, they are over 32%, even though demand has barely moved.

Where projects have been competitively bid, consumers have seen cost reductions of up to 40%. More than $100 billion in new transmission projects are in the



| Bureau of Labor Statistics

Year	Transmission Cost	Total Wholesale Electricity Price	Transmission as a Percentage of the Price
2014	7.36	108.53	6.78%
2015	8.90	58.27	15.27%
2016	9.86	51.45	19.16%
2017	11.00	54.67	20.12%
2018	10.89	62.61	17.39%
2019	11.90	51.28	23.21%
2020	13.78	45.15	30.52%
2021	14.51	66.07	21.96%
2022	15.28	99.00	15.43%
2023	16.66	53.11	31.37%
2024	17.89	55.14	32.44%

PJM Transmission Owners' annual transmission formula rate informational filings | *PJM Transmission Owners*

planning stage or in implementation, which should give FERC impetus to act to reduce costs.

Failures by FERC, RTOs and states to embrace and enforce competition are at the heart of high transmission costs. Electric utilities spend tens of millions of dollars per year lobbying to protect their monopoly and have largely succeeded. Homeowners have no idea that their utility is putting profit over the interests of their customers. Utility actions to prevent competitive bidding of transmission lines is anti-consumer, anti-competitive, anti-market and anti-American.

Consumers support competition, as does President Trump. One of his executive orders calls for each federal agency to root out regulations that are harmful to competition. Trump has pledged to reduce the cost of energy, and this is a good example of regulations that are anti-competitive and drive up the price of electricity for decades to come.

When a new transmission line is put into the rate base, consumers will pay for it over the next 40 years or more. Added to the cost of the transmission line is a rich ROE and financing costs that can increase the total cost by seven to eight times.

Building transmission lines is a lucrative business for utilities, which is why they fight against competitive bidding of transmission lines at FERC, at RTOs and in their states. In 2024, utilities pushed legislation in Oklahoma, Wisconsin, Indiana, Missouri, Illinois and Kansas that that instituted rights of first refusal, preventing transmission lines in their territory from being competitively bid.

The Industrial Energy Consumers of America has filed several legal complaints and motions for rehearing that have been sitting at FERC, some for months and others for years. Those filings would be a good place to start and also eliminate the "candy," as Christie calls it. The candy is transmission economic incentives that are not needed, inflate costs and are inconsistent with "just and reasonable" rates.

Chairman Christie, the moment is now: Finish what you began and break the grip of monopoly transmission and escalating electricity prices. Let your tenure end with a bang. ■

Paul Cicio is president of Industrial Energy Consumers of America and is a consumer advocate.

FERC Independence Likely Coming to an End with Christie's Exit

By James Downing

While the reported pick of David Rosner to be chair of FERC might appear to be a rare bipartisan move from the White House, sources familiar with the issues said in interviews that it represents another step in exerting control over what historically has been an independent agency. (See related story, *Reports: Trump to Name Democrat Rosner as FERC Chair*.)

Sources who know FERC well were granted anonymity to speak candidly with *RTO Insider* about politically sensitive issues.

On Aug. 8, several outlets reported that a White House source said Rosner would be named chair. But as of close-of-business Aug. 11, the White House had yet to designate a chair, and FERC's website listed only three sitting commissioners. Without a chair, the agency cannot issue orders. In the past, former Commissioner Bill Massey was named chair for literally a *weekend* as President Bill Clinton was transferring power to President George W. Bush during the Western Energy Crisis.

President Donald Trump issued an executive order in February directing FERC and other "so-called" independent agencies to submit proposed and final significant regulatory orders to the Office of Information and Regulatory Affairs for review before they could be published in the *Federal Register*. (See *Trump Claims Authority over Independent Agencies in Executive Order*.)

Former Chair Mark Christie, who stepped down from the agency Aug. 8, actually spent most of his first press conference defending that order, arguing that FERC never enacts policies at cross purposes with the White House's goals. But he also said he never would allow discussions of pending items before the commission covered by *ex parte* rules. Ultimately, he proved too independent for this White House. (See *FERC's Christie Says Existing Policies Can Align with Trump Order*.)

While the idea of ending FERC independence might seem short-sighted given that Democrats could retake the White House in 2028, one source said the view there now is "to the winner goes the spoils" and some members of the minority party would be happy to steer the agency when they are next in control of the presidency.

Why This Matters

Assuming the Trump White House wins at the Supreme Court, FERC and other independent agencies likely will see the same kind of wild policy swings when the presidency changes parties as has been seen at other agencies such as EPA and DOE.

Nobody who spoke with *RTO Insider* could remember a time when a White House had passed over a nominee from their own party to name a chair from the other. In Trump's first term, he demoted Norman Bay and elevated Cheryl LaFleur to run the agency again, but there were no Republicans on the commission after a dispute between President Barack Obama and members of the Senate Energy and Natural Resources Committee over nominees.

Opposition from former Sen. Joe Manchin of West Virginia (at the time a Democrat, though he converted to independent in 2024 before leaving office) to nominee Ron Binz and then making Bay the chair was part of that dispute with Obama. Manchin went on to chair that Senate committee and was a major supporter of Rosner, who was detailed to it from FERC before being nominated.

Everyone interviewed by *RTO Insider* praised Rosner as a well-qualified commissioner who would do a good job for as long as he runs the agency. But his pick could indicate the White House is favoring nominees who back specific policies as part of its efforts to control FERC.

Sources pointed to the order from November when Christie and Commissioner Lindsay See voted against allowing a data co-location contract between Amazon Web Services and Talen Energy. (See

FERC headquarters in D.C. | © *RTO Insider*

FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant.)

The co-location order proved unpopular with owners of merchant nuclear plants who value the deals to hedge against the possibility of lower power prices in the future, which would help keep them open for decades. Data center developers also were not happy, but with the largest of them having massive balance sheets, they have found ways to keep expanding.

One source said Rosner has proven more eager to support natural gas infrastructure development, while See appears more inclined to pay heed to legal arguments that FERC needs to consider their environmental impacts and emissions.

Trump has nominated Laura Swett and David LaCerte to the two open seats on the commission, and the Senate likely will move on those nominations this fall. Swett has been expected to be named chair, and while sources likewise praised her abilities, she also might have been nominated due to being more willing to work with the White House than Christie was.

One source said Rosner could make that same deal and stay as chair even after Trump gets his own nominees on the commission.

Regardless of who runs FERC for the next several years, the issue of its independence, and that of all similarly structured agencies, is going to rise to the Supreme Court, where the same "unitary executive theory" the White House is pursuing is popular among Republican justices.

In an order from May 22 overruling a stay that would have stopped Trump from firing members of the National Labor Relations Board and the Merit Systems Protection Board, Chief Justice John Roberts wrote the government was likely to win that case, though the question is better left for resolution after a full briefing and argument.

Justice Elena Kagan, joined by the two other Democratic nominees on the court, pushed back on the chief justice's argument that such agencies exercise considerable executive power on behalf of the president.

"Congress created them all, though at different times, out of one basic vision," she wrote. "It thought that in certain spheres of government, a group of knowledgeable people from both parties — none of whom a president could remove without cause — would make decisions likely to advance the long-term public good." ■

DC Circuit Remands LG&E-KU De-pancaking Requirement to FERC

By James Downing

The D.C. Circuit Court of Appeals on Aug. 8 remanded to FERC an order rejecting a mitigation plan LG&E and KU Energy filed to replace its longstanding obligation to de-pancake rates for wholesale customers (23-1196).

The court found that FERC did not adequately consider whether the utility's transition mechanism provided ratepayers protection from the removal of the rate schedule the utility instituted in 2006 when it left MISO. Schedule 402 ensured customers would not pay duplicate rates across its territory after Louisville Gas & Electric and Kentucky Utilities merged in 1998 while also reimbursing them for MISO's charges because the grid operator did not agree to reciprocally de-pancake its own rates.

After more than a decade of using Schedule 402, the company asked FERC to end its obligation, which the commission did in 2019, on the condition that the utility institute a transition mechanism. But the commission reversed itself on remand from the D.C. Circuit in 2023 and directed the utility to reinstitute 402. (See FERC Upholds De-pancaking Provisions in LG&E/KU Rates.)

In its decision, FERC declined to use the pre-merger status quo — which would have rates pancaked between MISO, LG&E and KU — as a point of reference. The utility argued that FERC should have used that as a baseline and that its retail customers were picking up the costs of de-pancaking rates with MISO for wholesale customers. The utility also proposed a transition mechanism that would have continued de-pancaking some rates for wholesale customers for decades, which it argued would fully mitigate any impact on wholesale rates.

"We are not satisfied that the commission adequately addressed this important issue: that the transition mechanism agreements would have protected each customer with a reliance interest, thereby mitigating any concern that customers continue to need Schedule 402 to protect their reliance interests," the court said. "In fact, during oral argument, counsel for FERC suggested that the transition mechanism agreements could be a potential protection offered to mitigate or end the need for de-pancaking."


| LG&E

Eighteen municipal customers benefit from the de-pancaking, and 12 of them would be covered by the transition mechanism or some other agreement. The other six do not take service from MISO.

FERC needs to consider whether the transition mechanism is enough to get rid of Schedule 402, the court ruled.

"We do not make that determination for the commission but simply remand the case back to the commission so that it can weigh the evidence and determine whether the transition mechanism agreements would adequately protect ratepayers," the court said. ■

FERC Chair Mark Christie Leaves Agency After One Last Dissent

By James Downing


FERC Chair Mark Christie | © *RTO Insider*

FERC Chair Mark Christie officially stepped down at the close of business Aug. 8, leaving the commission with a quorum of three until the Senate considers two pending nominees from President Donald Trump.

Christie already presided over his last meeting in July, which offered his colleagues a chance for a public send-off, and he took questions on his tenure. (See *Christie Says Farewell to FERC at Final Meeting as Chair*.)

He posted his last *letter* outlining FERC's work over the previous week, which he started writing after Elon Musk emailed all federal employees asking them to send emails doing the same in February.

On Aug. 7, Christie *posted* on Musk's social media site X that he had filed his last dissent as a FERC commissioner, in which he sided against the majority who partially granted a complaint Savion filed against PJM (EL25-63).

In the *order*, the majority sided with Savion, which argued it should have gotten an extension on an interconnection construction service agreement (ICSA) for a 66-MW solar development it was building at the same site, with the same point of interconnection, as an existing 111-MW solar plant it previously built. The project was built on a former surface coal mine in Martin County, Ky.

Savion argued PJM violated its rights under the ICSA, saying the RTO should have let it suspend work on the second part of the Martin project for 18 months after a construction firm building withdrew from the project unexpectedly and tariffs on solar panels were changed in 2024.

PJM said it was not eligible for suspension of the ICSA because the transmission infrastructure had been fully constructed.

FERC sided with Savion, finding that PJM improperly denied the suspension and saying that the 18-month suspension should be effective Dec. 14, 2024, when Savion first requested it. Some work is left to be done on the interconnection facilities, which means the suspension still can go into effect, the majority reasoned.

Christie dissented, saying the order would let interconnection capacity go unused and further disrupt and delay PJM's queue. AEP had finished building the transmission, and 111 MW of the Martin solar facility already was connected to the grid.

"The ICSA permits a project developer to suspend work 'associated with the construction and installation' of the transmission owner interconnection facilities," Christie said. "Here, the record demonstrates that 'construction and installation' is complete."

AEP has a couple of tasks to do, but the project is injecting power over the interconnection point. So just because some adjustments might be made, that does not mean there is remaining work that can be "suspended," he said.

"The majority's expansive reading of Section 3.4 would allow a customer to 'suspend' work through and including the time at which the project is operational and injecting power to the system and any time in the future," Christie said. "This reading is illogical. It is plainly at odds with the purpose of suspension, which is to stop work on interconnection facilities when the generating facility is delayed (not when the generating facility is operational)."

Christie said PJM "hits the nail on the head" in its argument that the complaint is seeking to delay completion of the project and in the process "hoard the interconnection capacity" in a way that is unfair to other projects that use the capacity.

"The resulting delays and uncertainty hinder development of new generation and stifles competition, which harms PJM at a time when it desperately needs that new generation; instead, today's order benefits a single developer to the ultimate detriment of consumers," Christie said. ■

Why This Matters

FERC will operate with a three-person quorum with Chair Christie stepping down about five weeks after his term ended on June 30. Two nominees are awaiting confirmation by the Senate, which is on recess until after Labor Day.

U.S. Peak Electricity Demand Sets Back-to-back Records

Preliminary Data Shows 759,180 MW Peak on July 29

By John Cropley

Peak electricity demand in the 48 contiguous states set records twice in the last week of July, reaching 758,053 MW and 759,180 MW over one-hour periods July 28 and 29.

The U.S. Energy Information Administration *announced the developments* Aug. 5 and attributed it to a heat wave coming amid the continuing growth of power demand.

The previous record was 745,020 MW, recorded July 15, 2024.

There is disagreement about how much and how quickly U.S. electric demand will increase, but there is wide consensus that growth will occur, due to transportation and building electrification, reshoring of manufacturing and the rise of energy-intensive artificial intelligence data centers.

The EIA's forecast calls for electricity demand to grow by an annual rate of just over 2% in 2025 and 2026.

This is a marked change from much of the century so far, EIA said, noting that *average annual increase* in demand was only 0.1% from 2005 to 2020 and just 0.8% between 2020 and 2024.

The back-to-back demand records at the end of July came as much of the nation was within a heat dome, subjecting tens of millions of Americans to very high temperatures and causing their air conditioners to consume more electricity.

Preliminary data from EIA's *Hourly Grid Monitor* indicates the new all-time peak, 759,180 MW, was reached about 6 p.m. Eastern time July 29.

Why This Matters

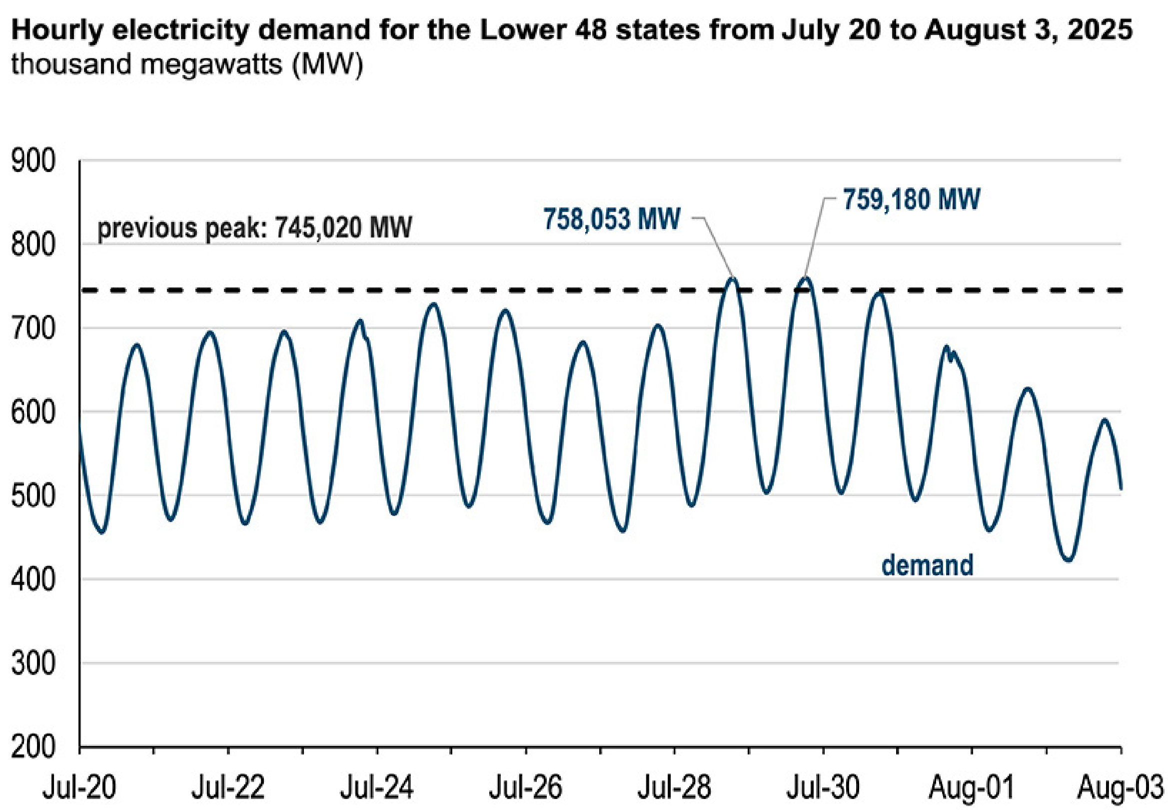
The record peaks are an extreme example of the increasing load being placed on the grid.

The Grid Monitor indicates that in the 60-minute period:

- The highest demand was in the Mid-Atlantic (154,380 MWh), Midwest (129,574 MWh) and Texas (81,572 MWh).
- The major energy sources meeting this demand were natural gas (348,891 MWh), coal (133,711 MWh), nuclear (95,287 MWh) and solar (88,389 MWh).
- Two other renewables were far behind — hydropower was near its peak output for the day at 39,392 MWh, while wind turbines produced only 25,772 MWh, down 57% from their peak output for the day, reached 16 hours earlier.
- The U.S. imported 5,883 MWh from Canada and exported 230 MWh to Mexico.

Daily demand peaks began to subside after July 29, preliminary data shows, dropping to 631,287 MWh from 6-7 p.m. Aug. 1.

Over the weekend, the peaks dipped further to 588,925 and 600,233 MWh. They bounced back to 645,449 MWh as the work week began Aug. 4. ■



The U.S. Energy Information Administration reports record peak demand in the contiguous 48 states on July 28 and 29. | *EIA*

Clean Energy Groups Seek Rehearing on DOE Resource Adequacy Report

Groups Contend Document Appears to be More 'Protocol' than Analysis

By James Downing

The groups that filed the rehearing request worry that it will be used to justify more orders under Section 202(c) of the Federal Power Act, which kept open units at Constellation's Eddystone plant this summer. | *Constellation*

Three clean energy trade groups have asked the Department of Energy to reconsider its recent report on resource adequacy, which they contend uses a deterministic approach to stake out a position for not retiring any more power plants in the face of rising electricity demand.

The American Clean Power Association (ACP), American Council on Renewable Energy (ACORE) and Advanced Energy United (AEU) filed a *request* for rehearing Aug. 6, saying DOE should rework the report to offer a more clear-eyed view of the risks the industry faces with exploding demand stemming from the growth of data centers and other large energy customers. (See *DOE Reliability Report Argues Changes Required to Avoid Outages Past 2030*.)

"As demand for energy surges, grid reliability must rely on sound modeling, reasonable forecasts and unbiased analysis of all technologies," the groups said in a statement. "Instead, DOE's protocol relies on inaccurate and inconsistent assumptions that undercut the credibility of certain technologies in favor of others."

The report uses forecasts for high demand coupled with projections for limited new supply that include only NERC Tier 1 planned generation — resources already under construction or with firm in-service dates. That means DOE effectively assumes no new generation will go online after 2026 in a report that extends to 2030, John Hensley, ACP senior vice president of markets and policy analysis, said on a call with reporters.

"We are all kind of cognizant of the challenges facing us over the next 10 years as energy demand is starting to skyrocket, at the same time that there are very active debates going on right now, thinking about taking a lot of resources off the table that could help to meet that demand going forward," Hensley said.

A recent *RTO Insider* story cited industry experts who raised similar concerns about the report, prompting DOE to defend its methodology. (See *Industry Experts Find Fault in DOE's Resource Adequacy Analysis*.)

The agency said its future data center demand estimate represented a midpoint from 2024 studies by the Electric Power Research Institute and the Lawrence Berkeley National Laboratory and acknowledged the report's "conservative yet realistic baseline" for new generation, but pointed also to supply change challenges the electric sector faces, which could lead to major construction delays.

Former Kentucky Public Service Commission Chair Kent Chandler said the report relies on one scenario with limited supply growth to push the argument for no retirements. While that could offer evidence of how the industry and its regulators are falling short, it is not enough, he said.

"It is certainly not, in my opinion, sort of my former regulator hat, useful for the singular purpose of saying all power plants need to stay on at all cost, or build all new power plants at all costs," Chandler, now a senior fellow with R Street, said in an interview.

Most studies assessing future resource adequacy would use various scenarios and rank the probabilities of occurring, but by its own admission DOE's report does not do that, Chandler said.

Why This Matters

The groups filing the rehearing request argue DOE is using the RA report to expand its authority under Federal Power Act Section 202(c) to include preventing power plants from retiring, rather than its traditional use of maintaining short-term reliability.

A 'Protocol' for Retirements

Some industry observers have argued DOE could use the report's findings to issue more orders under the Federal Power Act to keep plants from retiring, as it did with the Campbell plant in Michigan and the Eddystone plant in Pennsylvania.

"It's directly tied to that," AEU Managing Director Caitlin Maquis said on the call with reporters. "DOE's analysis came out of Executive Order 1462 back in April that directed DOE to put this analysis together, and then, as part of that same executive order, directs DOE to use all mechanisms available, including FPA Section 202(c) to retain resources it deems necessary in regions it's identified as having inadequate reserve margins."

A rehearing request for a DOE report is rare, but the groups call the document a "protocol" that will be used to keep more power plants open under the FPA.

The rehearing request argues the report amounts to "an effective amendment to DOE's existing regulation governing 202(c)."

"In the rehearing request, we go through pretty extensively the reasons that this protocol from DOE may be styled as a report but really looks like agency action that is intended to have real world effects," Gabe Tabak, ACP general counsel, told reporters. "It is not, as folks sometimes call government reports, a piece of shelf art that is just going to sit there. So, even though it is labeled as a report, in our view, it clears the bar as agency action and therefore qualifies as a type of action where hearing is appropriate to seek."

Although preventing retirements in the face of rising demand can be prudent, maintaining all plants that were on the path to closure absent that growth doesn't make sense, Hensley said.

"Deferring that decision making to the utilities themselves and their PUCs is the right course of action," he added. "They understand what their fleet looks like. They understand the available options set in front of them and can make the best decision on what retirements to delay or new resources to bring online to meet that in a most economic way for ratepayers and to balance supply and demand."

Taking Politics out of the Picture

Chandler said Kentucky, a coal-friendly state, established a board to review all proposed plant retirements and make recommendations to the PSC regarding approval. He noted the board recently made no filing after a co-op asked to retire a small, broken combustion turbine plant that would have cost more to repair than new build.

"This body, who basically was put together for the purpose of keeping thermal fossil fuel-fired generation from retiring, was like, 'We take no position on the retirement either way,'" Chandler said. "They were never going to be for it, but they just couldn't come up with a reason to say, 'Yeah, let's keep it on.'"

"So, that's a long way of saying even those folks that are super interested in resource adequacy, or have a bias towards legacy, fossil fuel-fired generation — there are going to be many instances where it just does not make any sense at all for reliability or economic purposes to try to keep some of these plants on way past their economic life," he said.

That decision might have been different with a larger 650-MW power plant, which would be a major resource to take offline in one area, he added.

DOE has historically used Section 202(c) for limited circumstances when the grid is stressed and a power plant is running up against emissions limits from environmental rules, ensuring it will not be fined for exceeding air permits to maintain reliability — including this summer.

Chandler said one way to take the politics out of the retirement issue would be broadening how RTOs and ISOs employ reliability must-run (RMR) contracts. While most grid operators use RMRs as a stopgap to prevent grid problems as they address the consequences of removing a retiring plant from the system, ERCOT is one market that relies on the tool for resource adequacy after making a clear case, he said.

Chandler thinks Congress — or possibly FERC — could change rules to allow RTOs/ISOs to review the impact of retirements on resource adequacy and offer RMRs when needed.

"That removes a lot of the politics around depending on DOE to do 202(c) orders, and it frankly makes it probably a more sustainable practice and limits its application to just those instances where it's most necessary," he said. ■

CPower Conference Highlights DR's Opportunity from Data Centers

By James Downing

Why This Matters

Demand response has the potential to help data centers reach the market by better using the existing system, taking pressure off the need for new resources and power prices.

WASHINGTON — The growing number of data centers offers a major growth opportunity for demand response, as it can help get the energy-hungry facilities online quicker than new generation, executives and data center experts said at CPower Energy's GridFuture 2025 conference Aug. 6.

On top of that, renewables are growing, and their intermittency needs to be balanced, CPower CEO Michael Smith said at the event, held at the Omni Shoreham Hotel.

"We've dispatched more than we ever have this year," he said. "So, all of these things are conspiring to create a further need for flexible load on the system."

It takes a couple of years to build utility-scale solar and 15 years to build nuclear, he said. That does not factor how hard it is to get through the interconnection queues, or the relatively low forward prices in the markets compared to new-build costs that could rise further with the imposition of tariffs.

Duke University has shown that demand response could help unlock new data centers by making more efficient use of the existing grid, Smith said. (See *U.S. Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

Policymakers are starting to pay attention to that fact, with Senate Bill 6 in Texas requiring new loads at 75 MW or above to provide DR, ENP Consultants Director Jim McDonald said.

"You're going to see … a new version of Senate Bill 6" everywhere, McDonald said. "When AEP came out with their data center-only tariff a year and a half ago, that was a novel idea."

Many utilities now have adopted similar rules to AEP's, which require more upfront deposits to secure a place on the grid. The same week as the conference, Google announced deals with AEP's Indiana Michigan Power and the Tennessee Valley Authority to reduce power at its data centers when the grid is stressed in their territories. (See related story, *Google Strikes Demand Response Deals with I&M, TVA*.)

Training artificial intelligence models has been driving demand growth from the sector, and while that is energy intensive, once those models are trained, they are going to be put to work, which will use more power, said Morgan Scott, vice president of global partnerships and outreach for the Electric Power Research Institute.

"As we become more mature in the way that we use AI, it will continue to use more energy," Scott said. "Will we find efficiencies? Yes. Are these numbers wrong? Yes. But the point is, they are directionally correct and give you conceptually an understanding that this is going to continue to grow because of the way that we are going to use AI and what we are asking these models to do."

The hardware side also is changing quickly, with the lifespans of the equipment in data centers getting shorter and shorter. Microchips now degrade in one to three years and innovations are rolling quickly, she added.

"We're seeing massive jumps in terms of what that electricity draw is, and so you can see we actually have a forecast of 1.2 MW per rack in a data center because of those changes within Nvidia chips," Scott said.

The business opportunity for CPower and the DR industry in general is huge when it comes to the growing demand from AI, Smith said in an interview after the event.

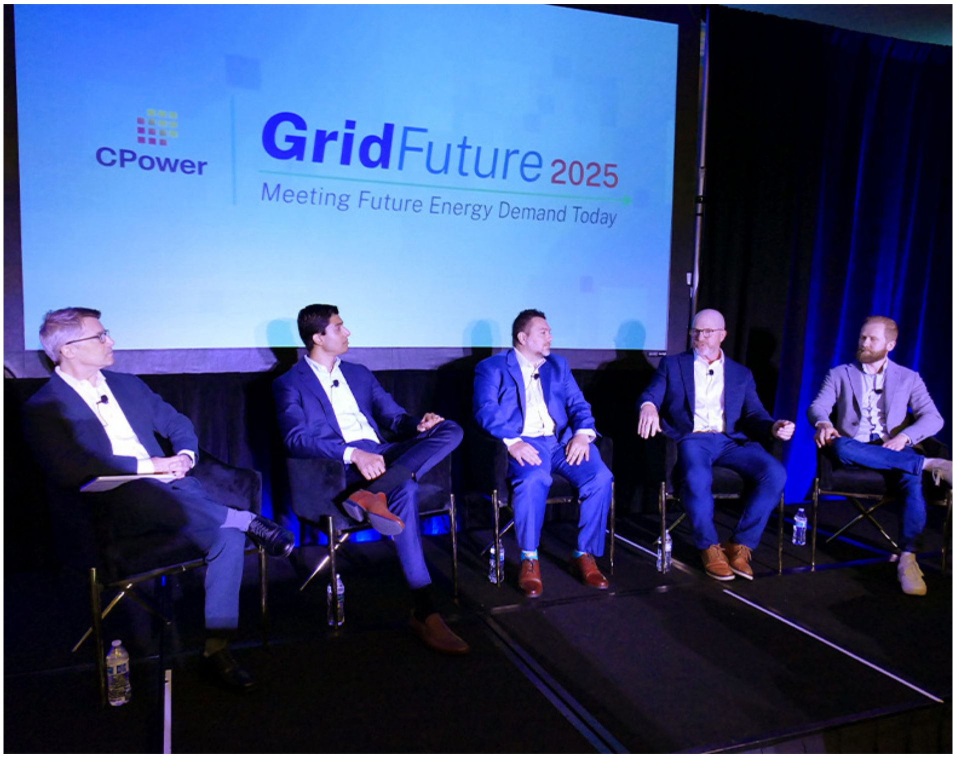
"Those activities can stress the grid because they can come on fast and they can consume a lot of electricity very quickly," Smith said. "So, that's exactly what we do. We're that shock absorber that monetizes or optimizes the value of the flexibility that's inherent in those machines."

CPower CEO Michael Smith addresses the GridFuture 2025 conference in D.C. | © *RTO Insider*

CPower and other DR companies are able to provide them a channel to monetize the flexibility that is possible in their operations, Smith said.

Data centers can offer flexible load either by curtailing their operations, including by shifting them to other sites, or using on-site resources such as backup generators or, as Duke explored in its study, batteries.

"We give the market operator access to those assets, and the market operator then can dispatch effectively those assets when needed," Smith said. "And it really is a dispatch protocol. ... A market operator can and should be able to dispatch a 500-MW peaking plant or a 500-MW data center equally."



From left: CPower's David Chernis, Emerald AI CEO Varun Sivaram, Bentaus CEO Bob Davidoff, ENP Consultants Founder Jim McDonald and Mercury Computing Co-Founder Monty Prekeris at the GridFuture 2025 conference | © RTO Insider LLC

AI Opportunities and Risks

CPower is looking into AI to help improve its operations. Smith said his sales team uses it to take notes in meetings, but eventually it should help with the software the company uses to manage aggregations of DR customers.

"It will help that software make better decisions about where to put various customer assets, in what programs [and] at what times," Smith said. "We do develop our own software. We have to be pretty cognizant of the tools that are available to us and use them appropriately. I'm not super comfortable just turning AI loose for the sake of turning AI loose, but I think our IT organization has done a really nice job of allowing AI to be used in the organization."

While the demand growth from AI and other sources presents opportunities for the entire power industry, it is not without its risks, CPower Chief Legal and Regulatory Officer Ken Schisler said in a separate interview.

"If we're not careful, what could be voluntary DR participation becomes power rationing, and that's going to be rejected by the public," Schisler said.

Conscripting demand flexibility like in Texas Senate Bill 6 could prove politically unsustainable as well, he said.

"People are going to want to see the transmission built or the power stations built so that they can use power when and where they want it, and if they have flexibility, they want to be able to make it available to the grid on their terms, rather than have it conscripted and rationed for them," Schisler said. "So ... unless you have those flexibility opportunities widely available, you're left with no choice but to sort of simply ration power."

Rising prices have led to political pushback, with states in PJM looking for reforms to cushion their consumers. Schisler said he is familiar with that dynamic from his time on the Maryland Public Service Commission. When the state restructured, it placed temporary caps on the price of electricity. Some utilities' caps expired in 2004 — just before natural gas prices spiked in response to two historic hurricanes, leading to much higher bills for customers.

"It happened right before Katrina and Rita" in 2005, Schisler said. "You wouldn't want to be me back in those times, and we're in one of those phases now."

States have been updating their policies and working to get reforms through at PJM in response to the situation, but one area Schisler said could help is improving access to data from customers to help enroll even residential customers into DR to save them money.

Data access varies by state. Schisler said ERCOT's market, wholly within Texas, is one of the best examples of making it easy and New York is working on reforms to do the same thing. But in multistate RTOs like PJM, it has proven much more difficult.

"I can go anywhere in the world, and I have a safe, secure banking system that I can get money out of an ATM, check my balance, etc., and know that that system is secure," Schisler said. "But we're still at a place where, at scale, interacting with utilities to get data is still a patchwork."

One way some companies have gotten around this is to install their own meters so they can help customers manage their loads, but that is economically wasteful, Schisler argued. The issue for data access has been around for years; President Barack Obama tried to address it with the *Green Button Initiative*, which Schisler called "an anti-standard."

"We're still acquiring data through lots of different channels now; Green Button didn't make that go away," he added. "The other challenge with it is it's largely an issue that is under the domain of state commissioners, yet the [reason] for accessing this data is for participation in wholesale markets, and we haven't bridged that need with state regulators and with utilities." ■

Interior Reverses Approval of Lava Ridge Wind Project

Controversial Idaho Facility Would Have Been Among Nation's Largest

By John Cropley

The Department of the Interior is moving to cancel the Lava Ridge Wind Project, a gigawatt-scale wind farm proposed on thousands of acres of federal land in Idaho.

The proposal had long been the target of criticism within the state. President Donald Trump ordered all development halted in a *Day One memorandum* Jan. 20 so Interior could review the record of decision issued six weeks earlier.

On Aug. 6, *Interior announced* the review had uncovered crucial legal deficiencies in the "reckless" and "thoughtless" approval issued under lame-duck President Joe Biden.

"This decisive action defends the American taxpayer, safeguards our land and averts what would have been one of the largest, most irresponsible wind projects in the nation," Interior Secretary Doug Burgum said.

Lava Ridge developer Magic Valley Wind and its corporate parent, LS Power, did not respond to requests for comment for this report.

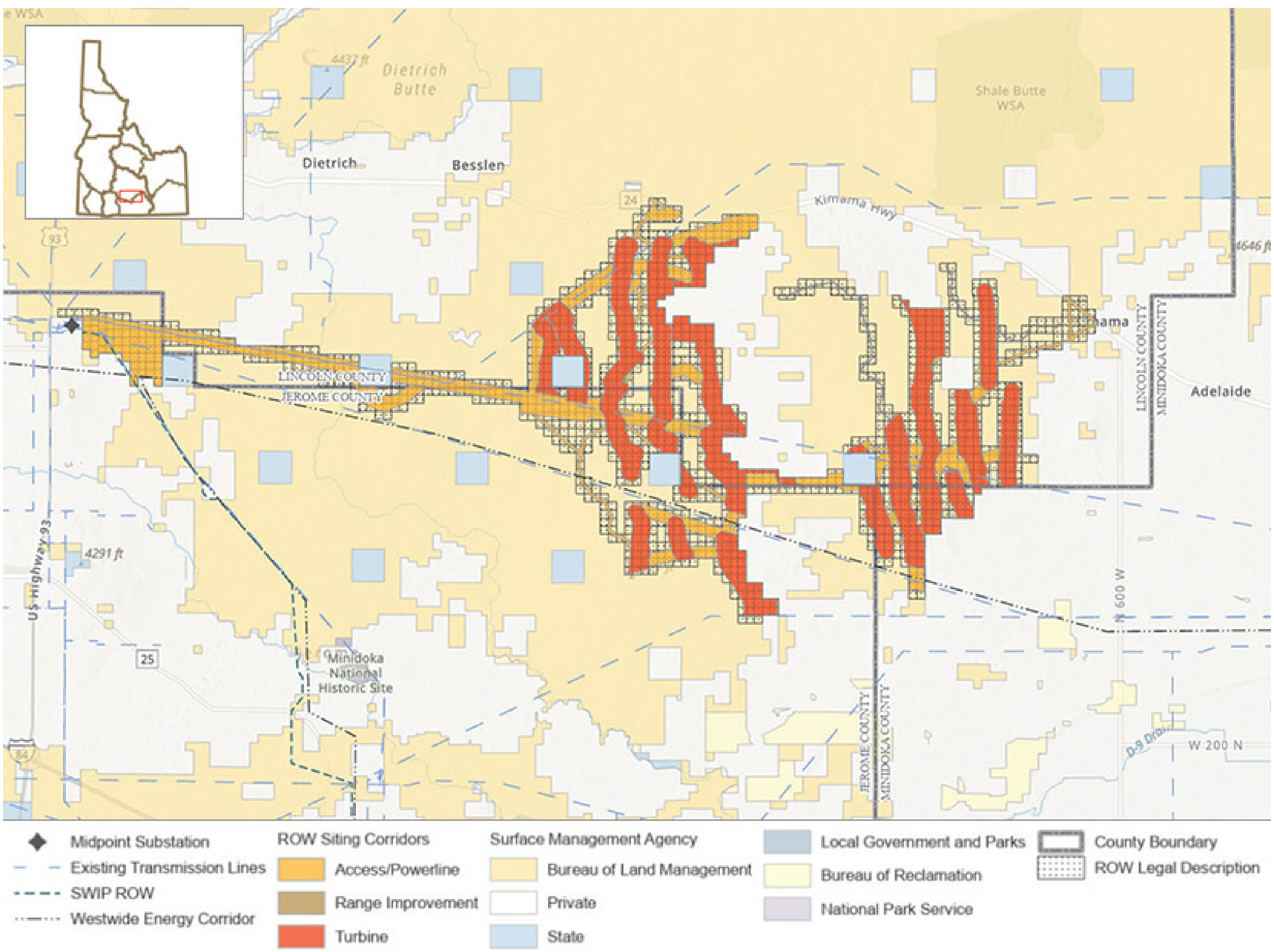
Interior's decision is the latest in a series of directives and policy actions by Trump and his cabinet agencies to thwart renewable energy development, one of

Why This Matters

The latest anti-renewable energy move by the Trump administration blocks a major wind facility planned in Idaho.

Biden's signature initiatives. (See *Feds Pile on More Barriers to Wind and Solar* and *Trump Administration Takes Another Swing at Wind Power*.)

Trump instead is seeking to maximize fossil fuel use. A reminder of this came later Aug. 6, when Interior announced it



The layout of the Lava Ridge Wind Project is shown in a map provided by the U.S. Bureau of Land Management. | *BLM* had advanced the *first expedited coal lease* under provisions of the One Big Beautiful Bill Act. A day earlier, Interior announced it had approved the *second-largest coal mine expansion* since Trump returned to office — a move intended to enable extraction of 33 million tons of coal at a Montana mine.

Lava Ridge was proposed in 2021 with up to 400 wind turbines disturbing 9,114 acres. During the Bureau of Land Management review process, it was reduced to 231 turbines and 992 acres disturbed, with the overall footprint reduced to 38,535 acres. BLM issued a favorable record of decision Dec. 5, 2024.

Nameplate capacity was to be at least 1,000 MW, which would nearly double the roughly 1,100 MW of wind power installed statewide in 2024. Idaho's largest existing wind farm in 2024 was rated at only 160 MW, according to the *U.S. Energy Information Administration*.

Residents and elected leaders of the solidly Republican state mounted a vocal campaign against the plan on the grounds that it would be ugly; would be too close to the *Minidoka National Historic Site*, where civilian Americans of Japanese descent were held during World War II; and would send its electricity to California.

Idaho's congressional delegation and governor, Republicans all, had fought the Lava Ridge proposal all the way through to BLM approval and then continued after. On Aug. 6, they took a victory lap.

"I made a promise to Idahoans that I would not rest until the Lava Ridge Wind Energy Project was terminated," *U.S. Sen. Jim Risch said*. "Today, President Trump and I delivered on that promise."

On X, *Gov. Brad Little* praised Trump and Burgum: "On behalf of all Idahoans — thank you for your leadership."

BLM said in December it had worked to reduce the impacts of the original proposal on wildlife, cultural resources, local aviation, ranchers who use public land and adjacent private landowners.

Minidoka, where more than 13,000 Japanese Americans were interned, had become a bit of a rallying point for opponents, as alternate iterations of the Lava Ridge plan would have put turbines much closer than the nine miles in the final version.

Turbines already spin southeast and southwest of the concentration camp site — most of Idaho's existing wind energy generation is in the Snake River Valley.

California Impact?

It is unclear what impact the cancellation of Lava Ridge will have on California's ambitious plans to reduce its electricity emissions, which include extensively tapping output from wind resources in the inland West. As part of that effort, the California Public Utilities Commission's (CPUC) integrated resource planning portfolio calls for the state to procure more than 1,000 MW of wind generation from Idaho.

Unclear also is the effect on another LS Power project, the Southwest Intertie Project-North (SWIP-North), a 285-mile, 500-kV transmission line being developed in northern Nevada by the company's Great Basin Transmission subsidiary.

Last year, the CAISO Board of Governors finalized approval of a proposal to include SWIP-North as a CAISO participating transmission owner (PTO) after ISO planners determined the project would be the only line completed in time to help deliver Idaho wind to California's load-serving entities by 2027.

While development of SWIP-North has not been tied to any single generation project, most of Lava Ridge's output was expected to be exported on the southbound segment of the line. In response to past stakeholder concerns about the line's dependence on Lava Ridge, CAISO *pointed out* that "CPUC portfolios for out-of-state wind resources in Idaho are based upon generic wind resources and not specific to any one specific facility such as Lava Ridge."

Sources have told *RTO Insider* that the CAISO PTO designation for SWIP-North likely influenced Idaho Power's leaning in favor of joining the CAISO Extended Day-Ahead Market (EDAM) rather than SPP's Markets+. But even with the Lava Ridge cancellation, Idaho Power's interest in SWIP-N would appear to be secure, given that the utility plans to use the line to import power from the Southwest and not for exports.

"The SWIP-North project is the final segment of the larger SWIP project, which began decades ago. The urgency of completing the project has grown as growing energy demand across the Western United States strains the grid," Idaho Power *said* on its website. ■

EPRI, Epoch AI Estimate Power Demands of Artificial Intelligence

New Report Quantifies Expectations of Sharp but not Unlimited U.S. Growth

By John Cropley

A new report by EPRI and Epoch AI estimates U.S. power demand by artificial intelligence could jump from 5 GW today to more than 50 GW by 2030.

The sharp rise is due not only to the growth in the amount of large-scale training but also its increasing duration, and is tempered only partly by hardware efficiency improvements, the two organizations said in their Aug. 11 *announcement* of "Scaling Intelligence: The Exponential Growth of AI's Power Needs."

Beyond large-scale training, more power capacity will be needed for AI research and for the actual use of finished AI models. But the training needs alone are formidable: Power consumption for training cutting-edge AI models is doubling annually.

"Frontier AI training runs — the computationally intensive process of training large, advanced AI models — currently consume approximately 100-150 MW each and are projected to reach 1-2 GW each by 2028, exceeding 4 GW per training run by 2030," the authors write.

Training duration is assumed to have a 10 to 20% annual growth rate in the future. This compares with 25 to 50% in recent years. Increasing the duration can spread the same amount of power use across over a longer period, smoothing out peak demand. But the authors say durations now exceed 100 days, so further increases may yield diminishing returns.

Meanwhile, for the study, hardware efficiency is assumed to improve 33 to 52% annually.

The authors say the split of demand between training AI models and using them is important, as it could affect the size, location, power demands and potential flexibility of AI data centers. But it is currently uncertain, and the landscape is changing rapidly.

Why This Matters

The report offers one more projection of what is expected to be one of the largest upcoming demands on the U.S. grid.

Some forecasts show AI consuming more than 5% of U.S. generation capacity by 2030, with some training runs equivalent to the output of entire power plants.

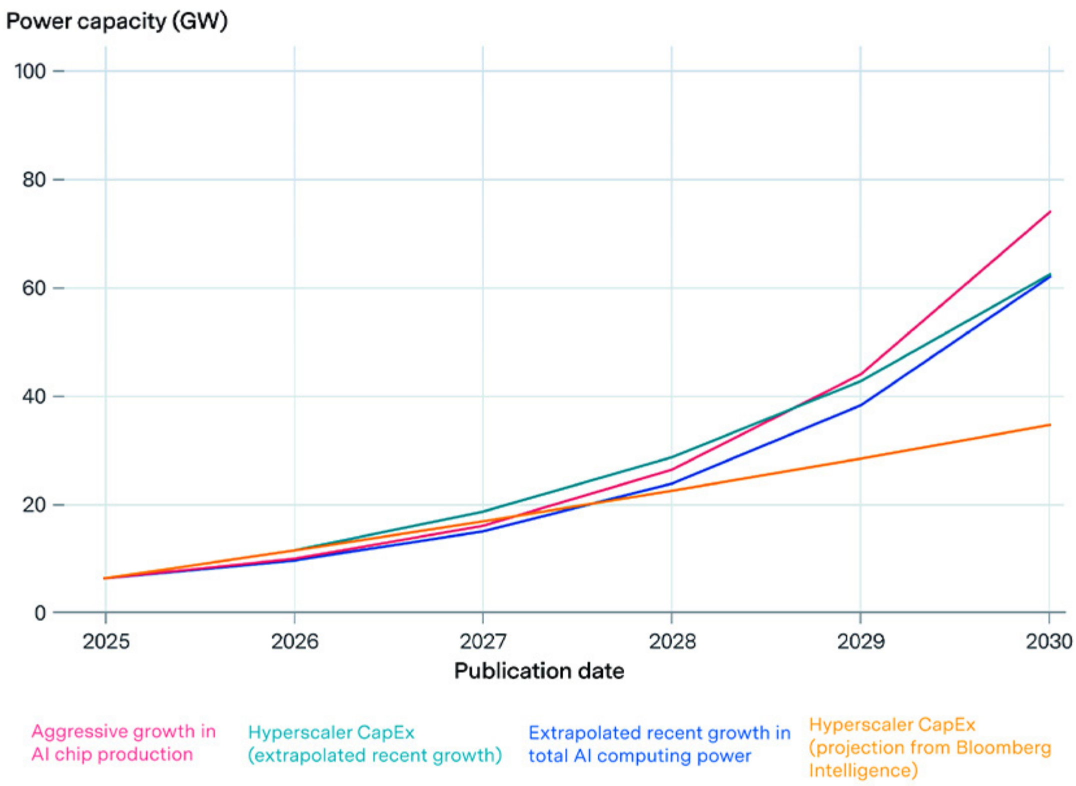
As has been noted many times, meeting such a level of peak demand just with new capacity could be quite challenging and extremely expensive. Some flexibility of demand during peak periods would help make the process less expensive and difficult.

The authors suggest: "Planning should account for both concentrated and distributed data center loads as well as the potential for real-time flexibility in training and inference workloads and from on-site generation and storage assets."

"Inference" — usage of a trained AI model, such as generating responses to user requests — could support more flexibility than AI training.

The authors state that the rapid rate of growth of AI computing seen recently and projected in the next several years almost certainly must slow by the 2030s, because it is accompanied by a growth in cost that is not quite as rapid but is nevertheless unsustainable.

Whether that slowdown starts before 2030 may depend on technical innovations, data constraints or diminishing returns to scaling, they write. ■



Power consumption by AI data centers in modeled under four scenarios. | *EPRI and Epoch AI*

New Tech, Collaboration Key to Targeted PSPS, WECC Panelists Say

By Henrik Nilsson

As large swaths of the West continue to explore ways to mitigate wildfire risk, utilities say information sharing and new technologies allow them to implement targeted public safety power shutoffs (PSPS).

Representatives from three utilities discussed PSPS during a *webinar* hosted by WECC on Aug. 6. A PSPS is when an electric utility temporarily shuts off power to reduce the risk of wildfire caused by the company's equipment.

Southern California Edison, which serves about 15 million customers, has approximately 1,800 weather stations that are deployed across high-risk wildfire areas and provide real-time updates on conditions, said Kevin Alirez, a senior adviser with the utility.

But in an effort to avoid PSPS, SCE has "aggressively pursued grid-hardening efforts" around areas that are most prone to PSPS, including undergrounding of transmission lines and covering conductors, Alirez said.

"We're installing more isolating devices as well across our distribution circuits so that we can be more surgical and more precise on those specific areas across our grid to do those de-energizations," he added.

SCE is also looking at microgrids as a strategy for PSPS "where it makes sense," according to Alirez.

"Battery energy is a big thing coming out too," Alirez said. "So where can we potentially add battery energy storage units across our grid that would make most sense from a PSPS de-energization perspective?"

Why This Matters

As wildfire risk continues to increase in the West, utilities must navigate customer safety and ensuring that power stays on.

Washington State Department of Transportation

Carrie Laird, managing director of emergency management and meteorology at PacifiCorp, said PSPS is a last resort in wildfire mitigation.

To reduce the impact of PSPS, PacifiCorp focuses on sectionalizing its system "so that we can impact smaller subsets of customers with the introduction of … smart protective devices, early fault detecting devices," Laird said.

The utility uses cameras powered by artificial intelligence, among other technologies, to detect wildfires faster, according to Laird.

Laird also noted that because of the challenging geography of PacifiCorp's service area, the utility's communications connections to its transmission and distribution system have been "pretty far behind the big California utilities … so that's a huge area of focus."

For the Public Service Company of New Mexico, PSPS is a great tool, but the goal is "to never have to do a PSPS," according to Thad Petzold, associate director of wildfire risk and vegetation management.

"The first thing you do when you decide you're going to have a PSPS policy is try to minimize the impact to your customers," Petzold said. "And so you're using sectionalizers, and you're figuring out ways to really make those areas more granular … this isn't something that we necessarily want to do, but it's something that we will do for safety."

An important part of ensuring that a PSPS has limited impact is collaborating with other utilities and states, he noted.

"Because … otherwise you're stuck doing a lot of different trials and projects where you're trying … that out and the data takes such a long time to really incorporate," Petzold said. "So you look at what successful people do, you copy them, and you do it in, in our case, the most frugal way that we possibly can."

Similarly, coordination and communication between utilities is important to avoid customer confusion, especially when the counterpart does not have the same type of PSPS planning, according to Laird.

Still, with the threat of wildfires growing and high fire-risk areas constantly changing and expanding, Laird said a PSPS "can happen anywhere if the combination of … the fuels and weather conditions are right."

"It's not just [a] California problem anymore, and it's not just a … wild-urban land interface or rural problem either," she added. "The topic of urban conflagration is a hot one right now. So the preparedness piece of this could happen anywhere, and helping our customers get to a space where they're prepared should they be impacted is kind of an important area of focus." ■

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

Test Intended to Show Readiness for Hottest Part of Calif. Summer

By David Krause

An aggregation of more than 100,000 residential batteries provided an average 535 MW of support to California's electricity grid during a July 29 test to prepare for the hot summer period ahead.

The sea of home batteries formed a virtual power plant (VPP), comprising a group of customer-owned battery storage systems that are typically paired with solar panels. Local utilities, CAISO, the California Energy Commission (CEC) and other energy companies, such as Sunrun, released charge from the fleet of batteries onto the grid for two hours, from 7 p.m. to 9 p.m.

The VPP visibly reduced CAISO's net load during those peak demand hours, said representatives of The Brattle Group, which *studied* the results of the test.

"Performance was consistent across the event, without major fluctuations or any attrition," said Ryan Hledik, a Brattle principal. "Residential batteries — and other sources of distributed flexibility — can serve CAISO's net peak, reduce the need to invest in new generation capacity, and relieve strain on the system associated with the evening load ramp."

Most of the 535 MW would not have been available had the test not been initiated, according to Brattle.

"On peak days, using VPPs to serve CAISO's net peak could reduce the need to invest in new generation capacity and/or relieve strain on the system associated with the evening load ramp," Brattle said, adding that would help address challenges with California's "duck curve."

"Optimized VPP program design and coordination with the system operator could further maximize the value of the battery output to the system," Brattle noted.

Pacific Gas and Electric customers made up about 50% of test participants, Southern California Edison about 38%, and San Diego Gas & Electric about 12%.

Why This Matters

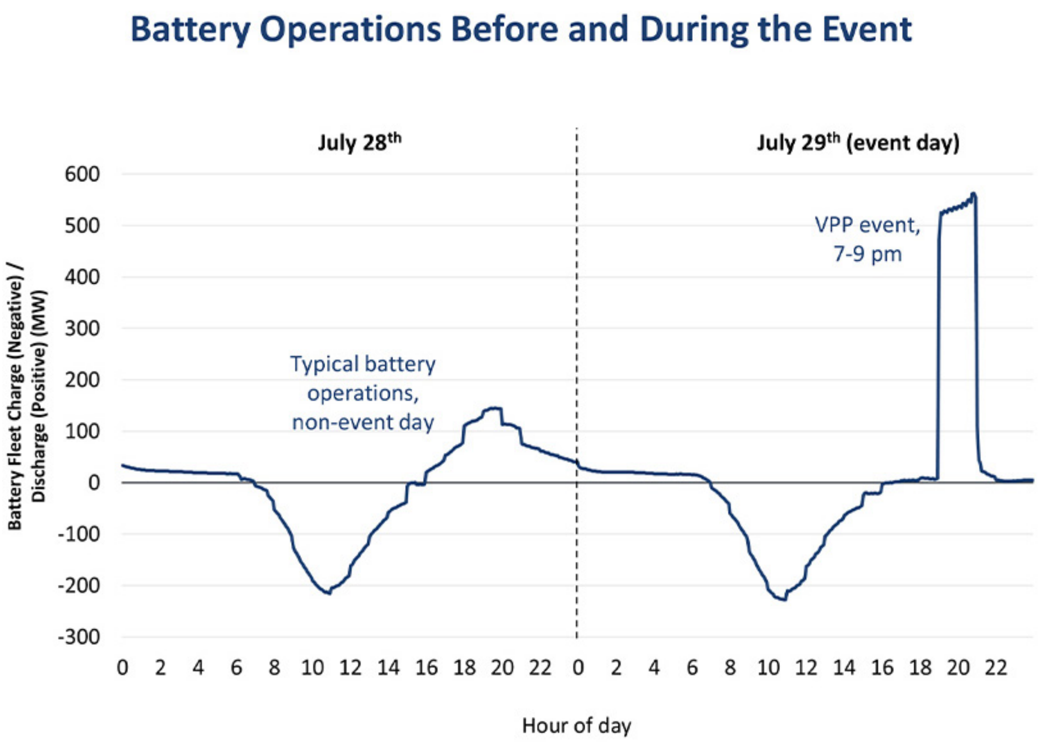
California energy officials are looking for ways to avoid rolling power shutoffs during the hottest months of the year. A program that sends home battery electricity to the grid during peak demand hours is meant to do just that.

Most of the batteries in the test are part of the CEC's *Demand Side Grid Support* (DSGS) program, which rewards customers who support the electric grid during extreme events. Rewards include payment for demonstrated capacity at varying monthly rates based on VPP capacity and duration, according to the CEC.

As of October 2024, the DSGS program had 515 MW of capacity and more than 265,000 participants. The program, which began in 2022, operates from May to October and is intended to help reduce the risk of rotating power outages during peak demand months. In 2024, the DSGS program turned on its VPP system 16 times.

The test on July 29 was not the first of its kind this summer: On June 24, Sunrun participated in a similar event in which its power resources provided 325 MW to the grid from 7 to 9 p.m., according to Sunrun. Participating Sunrun customers can receive up to $150 per battery per dispatching season, while Sunrun is paid for dispatching the batteries, the company said.

The CEC on Aug. 14 is holding a workshop on the performance of the DSGS program in 2024, specifically on VPP performance. ■



CAISO net load with and without home batteries supplying power to the grid. | *Brattle Group*

BPA Proposed Tx Access Changes Prompt Questions of Industry Readiness

Changes Could Shake up Status Quo for Financing Projects

By Henrik Nilsson

The Bonneville Power Administration's proposed changes to its grid access process have prompted questions about how new readiness criteria will impact established industry practices and financing of new projects.

In February, BPA paused certain transmission planning processes to consider changes in light of significant growth of transmission service requests. The federal power agency's 2025 transmission cluster study includes more than 65 GW of requests, compared with 5.9 GW in 2021. The requests exceed the total regional load predicted for the Pacific Northwest in 2034, according to the agency. (See *BPA Halts Some Tx Planning Processes Amid Service Requests* and *Industry Sees Challenges as BPA Considers 'Radical' Updates to Tx Planning*.)

On July 9, BPA outlined its proposed plan to tackle the queue during a workshop. The agency has developed a two-part approach: a transitional phase to get off the pause and a longer-term "future state" that will include more substantial reforms to BPA's existing transmission processes. (See *BPA Outlines Proposed Transmission Planning Reforms*.)

"In general, our current model will not work to effectively evaluate and respond to the massive amount of requests and megawatts in the BPA transmission service queue," BPA spokesperson Doug Johnson told *RTO Insider*. "The framework of our proposal revolves around instituting more rigorous requirements for transmission service requests. The goal is to process the queue as quickly as we can to advance our efforts to identify, plan and build the projects our customers need to do business as well as to provide interim service to those parties who have clarity about the service they need now."

Aerial view of BPA's Bonneville Dam | *Shutterstock*

Why This Matters

The proposed readiness criteria is an important piece of BPA's plan to deal with the interconnection queue and upcoming reforms to the transmission planning system.

As part of this effort, BPA has proposed implementing readiness criteria to weed out speculative requests from commercially ready projects.

"The current practice in the Northwest is for load-serving entities to require developers who are bidding into their request for proposals to provide their own transmission," Henry Tilghman, a consultant whose clients include Renewable Northwest and the Northwest & Intermountain Power Producers Coalition, told *RTO Insider*. (Tilghman spoke on his own behalf, not that of his clients.)

The load looking to purchase the output of a project doesn't provide the transmission — the project provides it, Tilghman explained.

"So that puts the burden on the developer to get into the queue and obtain transmission service," he noted.

Financing at Risk?

However, under BPA's new proposal, the agency would require evidence of security or a power purchase agreement or bilateral transaction between a load and resource to establish commercial readiness, Tilghman said.

"You would not be allowed to even request transmission service until you have an agreement in place or provide security," Tilghman said. "So that completely disrupts the existing model where the bidder into the [request for proposal] has to have transmission service placed in order to be eligible to bid."

This could impact financing of new projects, Tilghman contended. He said lenders have conducted risk assessments based on criteria that have been in place for decades.

"One of those criteria is having transmission service in place with enough certainty that the project will be able to deliver … its output to its customer," he added. "Now you're going to have to do development without that … transmission as you bring your project through the development process."

The Pacific Northwest Renewable Interconnection & Transmission Customer Advocates (PRITCA), a coalition whose members constitute more than 25% of the current BPA interconnection queue, has similarly expressed concerns over BPA's plans to apply commercial readiness criteria.

"Developers in the queue have generally sunk millions of dollars into developing their projects," Eric Christensen, an attorney with Beveridge & Diamond, which represents PRITCA, told *RTO Insider*. "The fact that developers are willing to put their own money on the line demonstrates that projects are commercially viable," Christensen said.

A more appropriate way to deal with the queue would be to study transmission requests in batches based on existing queue order, Christensen argued. He said this approach would allow viable projects to have a path forward to firm transmission while allowing unserious requests to exit on their own accord.

Because the proposals are new, it's unclear whether lenders have had time to analyze how they could impact investments, Christensen said.

"We talk with financiers regularly, and one of the big variables in financing decisions is a certain path to [long-term firm] transmission," Christensen added. "If BPA goes forward with the current proposal, we expect to see large financing cost increases or an unwillingness to provide financing, due to the uncertainty these changes create."

PUD Support

However, in public comments submitted to BPA, public utility districts have supported readiness criteria.

For example, Mason PUD said it "generally supports the addition of readiness criteria, so encumbrances are not provided for requests that will likely not convert to service. This will create an actionable queue [that] only includes mature long-term transmission service requests."

Additionally, Grant County PUD said it "supports the development of additional and clarified readiness criteria in order for TSRs to remain in the queue."

"Unknown and New-Point [Points of Receipt/Points of Delivery] should be deemed speculative and removed from the queue until and unless new procedures are developed to accommodate such PORs/PODs in a realistic and timely manner," Grant argued. ■

CREPC TC Issues 1st Cost Allocation Study

Voluntary Mechanisms Crucial for Cost Allocation in the West, Study Finds

By Henrik Nilsson

The Committee on Regional Electric Power Cooperation's (CREPC) Transmission Collaborative (TC), in collaboration with Energy Strategies, has issued its first cost allocation study to provide the industry with guidelines on how to tackle the thorny issue.

CREPC TC released the *State Exploration of Western Transmission Cost Allocation Frameworks* in conjunction with a *policy brief* Aug. 7. (See *CREPC TC Close to Wrapping Up Cost Allocation Study*.)

"The work conducted by Energy Strategies in consultation with the CREPC Transmission Collaborative to develop the State Exploration of Western Transmission Cost Allocation Frameworks policy brief and technical report is valuable to helping Western states better understand different cost allocation methodologies and implications," Gabriel Aguilera, New Mexico Public Regulation Commission chair and co-chair of CREPC, told *RTO Insider* in a statement.

"While nothing in this study is intended to be binding, states can build on the foundational elements of the study as transmission cost allocation discussions develop and evolve in the West," Aguilera said.

In an effort to strengthen stakeholders' understanding of the "challenges associated with regional cost allocation in the West," the TC members provided six takeaways from the report, according to the policy brief.

The six takeaways are:

- "Transmission cost allocation frameworks must result in the allocation of transmission capacity. Any transmission cost allocation framework that fails to align costs allocated with transmission capacity assignments (MW) is unlikely to be successful."
- Establish "well-defined thresholds, clear standards and independent expert input for ensuring that capacity assignments resulting from a cost allocation process are both meaningful and useful," the brief stated. "As part of this, cost allocation approaches should include rules to ensure that entities receiving de minimis benefits are not allocated costs."
- Because there is no broadly accepted method for measuring public policy and resource access benefits, the TC suggests that entities should be allowed to voluntarily subscribe to capacity on a line based on their own perceived benefits of certain transmission projects. This can address allocation disputes arising out of projects aimed at, for example, helping public agencies achieve decarbonization goals by transporting wind power from one state to another.
- Achieving a fully binding cost allocation process in the West is highly technical and difficult. Instead, stakeholders must agree that voluntary participation mechanisms are crucial for achieving significant transmission buildout, despite the risk of "free ridership." However, voluntary commitments can be converted into contractual or financial capacity or cost-share commitments as projects advance.
- Benefit quantification is a "critical foundation" for cost allocation. It is therefore important that those calculations be done with transparency, coordination and collaboration in mind.
- A transparent, well-defined and flexible process can help tackle some of the common issues that can arise during cost allocation discussions, such as preventing the overburden of individual utilities, accommodating different value systems and supporting fairness principles, among other benefits.

Why This Matters

The CREPC TC study aims to provide a pathway toward an effective cost allocation framework as part of an effort to improve transmission connectivity in the West.

To reach these takeaways, the TC and

ITC Midwest

Energy Strategies developed three cost allocation frameworks, based on different combinations of four cost allocation approaches: subscriber pays, beneficiary pays, zonal-cost assignment (costs are assigned on a load-share basis) and opt-in/-out (costs and project capacity are reassigned after initial allocation to entities volunteering to purchase additional capacity).

The frameworks were tested under three hypothetical interstate transmission projects. Two of the frameworks provided more proportionality, flexibility and optionality than the base case and were also preferred by stakeholders who provided input to the study.

"Despite a split on which framework is most appropriate, most representatives felt somewhat comfortable with the conclusion that these flexible, nonbinding cost allocation frameworks can help address Western states' concerns about misalignment between cost assignment and customer benefits," the brief stated. "Participants also recognized the crucial importance of the potential project participants voluntarily subscribing to capacity for these frameworks to be successful." ■

NRG Energy Secures $216M Loan from TEF

By Tom Kleckner

NRG Energy has closed on a $216 million loan from the *Texas Energy Fund* that will help it build 456 MW of gas-fired capacity at an existing power plant, the company said in a press release.

The funding will go toward the construction of two new natural gas units at NRG's TH Wharton power plant in the Houston area, the fifth-largest metropolitan area in the U.S. The company said the units will deliver power to the constrained load zone by summer 2026.

"Demand for electricity across Texas is surging and we're working quickly to supply new dispatchable natural gas generation to the grid," said Robert Gaudette, president of NRG Business and Wholesale Operations, in an Aug. 4 *statement*.

The loan is just the second issued by the Public Utility Commission since the fund's inception in 2024. The first went to the Kerrville Public Utility Board earlier in 2025. (See *First Texas Energy Fund Loan Goes to Kerrville Utility*.)

The 20-year loan, executed with the Public Utility Commission, will cover up to 60% of the projected $360 million cost, not to exceed $216 million, at a 3% interest rate through July 2045. The project must meet *minimum performance standards*, as outlined in the program's rules.

The two units already are under construction.

NRG has two more projects with another 1 GW of capacity that are progressing through the TEF's due diligence process. The PUC is reviewing 15 other applications for the TEF's in-ERCOT program, representing an additional 8.4 GW of capacity. The program, designed to add about 10 GW of gas-fired generation to the Texas grid, was approved by voters in 2023.

Two companies recently withdrew their projects from consideration by the fund, which is administered by the PUC.

LS Power *said* in June that it pulled a 527-MW project out of due diligence "due to numerous factors" and is no longer pursuing funds from the TEF program. In July, Hunt Energy Network *told* the PUC that it was withdrawing another due-diligence project because it "does not align with the requirements and conditions of the TEF loan in a cost-effective manner."

Six projects have been withdrawn by applicants or rejected by the PUC in 2025. (See *2 More Projects Fall out of TEF Loan Program*.) ■

Why This Matters

NRG Energy's $216 million loan is the second issued from the state's Texas Energy Fund. It will add 456 MW of gas-fired capacity to the ERCOT grid by the summer of 2026.

NRG Energy has closed on a loan to add 456 MW of gas capacity at its TH Wharton power plant. | *NRG Energy*

ISO-NE: Resources Overperformed During June Capacity Scarcity Event

By Jon Lamson

Pay-for-Performance (PFP) credits accumulated during the capacity scarcity conditions June 24 totaled about $114 million, a major boost in revenue for resources that performed during the event, ISO-NE COO Vamsi Chadalavada told the NEPOOL Participants Committee on Aug. 7.

The event was caused by the highest demand ISO-NE has experienced since 2013 and about 2,560 MW of generator outages and reductions. (See *Extreme Heat Triggers Capacity Deficiency in New England*.)

ISO-NE's PFP construct is intended to incentivize resource performance during capacity scarcity events. Resources earn credits by providing more power than their obligations, while resources that provide less power than their obligations face charges. Resources without capacity supply obligations (CSOs) also can earn credits by performing during shortfall events. On June 24, capacity resources earned about $67 million, while non-capacity resources earned about $47 million.

Credits and charges are intended to equal out, which is designed to protect ratepayers from the cost of incentives. However, ISO-NE has imposed a cap on the total monthly PFP charges a resource can accumulate, which caused a $26 million under-collection of PFP penalties on June 25. Under ISO-NE rules, the deficit between PFP credits and penalties is charged to capacity resources that have not hit the stop-loss cap.

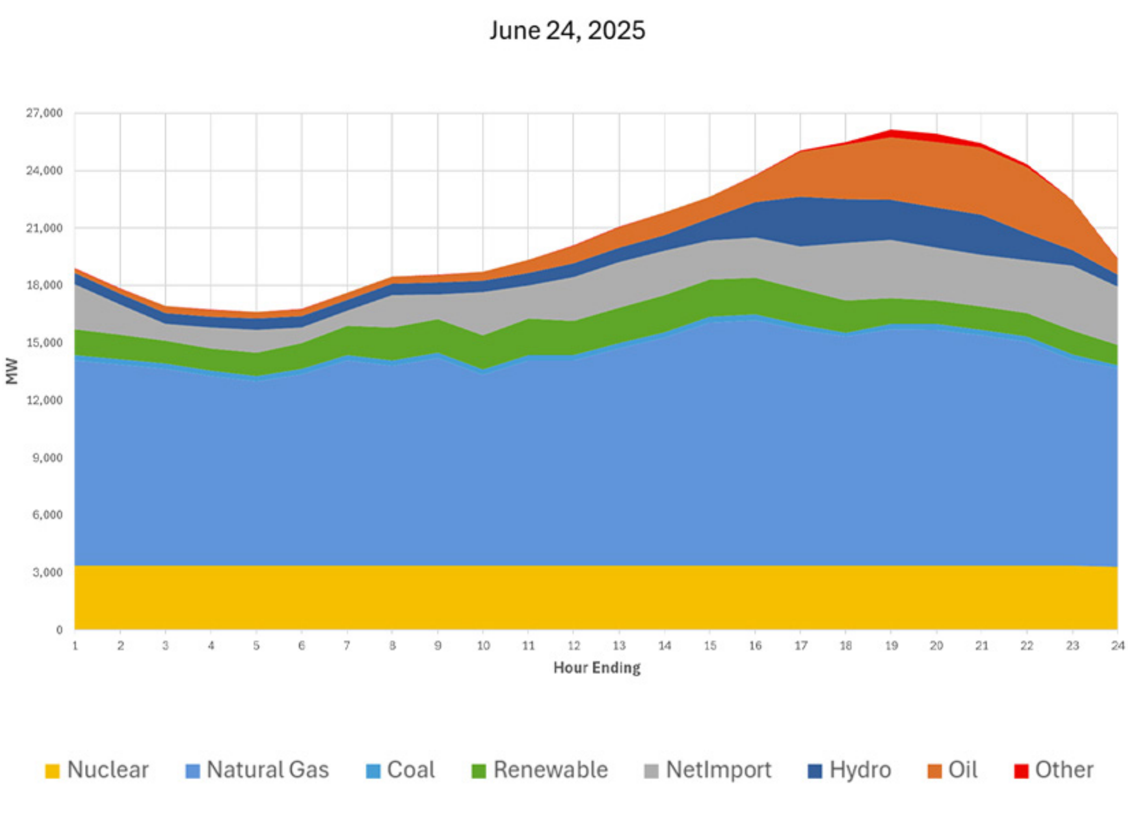
In the wake of the scarcity event, the New England Power Generators Association (NEPGA) filed a complaint with FERC contesting ISO-NE's rules on PFP charges, arguing the allocation method unfairly penalizes capacity resources that are below the stop-loss cap. (See related story, *NEPGA Seeks Relief for 'Improper' Pay-for-performance Costs in ISO-NE*.)

NEPGA also wrote that ISO-NE should cap its balancing ratio at 1.0, noting that the ratio exceeded that during the June 24 event, requiring capacity resources to provide more power than their capacity obligations. The balancing ratio determines the portion of each CSO that capacity resources are required to provide.

PFP charges and credits can have a major impact on each resource's overall capacity revenue. The overall capacity market value in June was about $88 million, $26 million less than the credits awarded during the three-hour scarcity event.

Interregional imports earned the majority of PFP credits, taking in $70 million. The total imports across ties with New York and Canada surpassed 4,300 MW around the peak period of the event.

In-region generation resources earned about $36 million but racked up $99 million in charges. This calculation includes the reallocation of the deficit of funds caused by the stop-loss cap.



ISO-NE energy by source on June 24 | *ISO-NE*

Monthly Operations Report

Energy market revenue totaled about $1 billion in July, compared to $672 million in July 2024, Chadalavada noted in his monthly report on system operations.

Chadalavada said the significant load fluctuations experienced in New England over the spring and summer demonstrate the increasing demand volatility challenges in ISO-NE. The RTO experienced its lowest recorded demand in April, more than 20,000 MW below the 26,000-MW system peak experienced on June 24. (See *Growth of BTM Solar Drives Record-low Demand in ISO-NE*.) ■

Massachusetts Seeking 1,500 MW of Mid-duration Energy Storage

By Jon Lamson

Shutterstock

The Massachusetts Department of Energy Resources and the state's investor-owned electric utilities have issued a request for proposals to procure up to 1,500 MW of mid-duration energy storage, a key step toward the state's goal of contracting 5,000 MW of energy storage by mid-2030. The procurement marks the largest energy storage solicitation issued to date in New England.

The state also outlined its expected timeline for future storage solicitations, noting that it plans to issue additional 1,000-MW mid-duration storage procurements by July 31, 2026, and July 31, 2027, and wrote that "all remaining energy storage systems capacity shall be procured by July 31, 2030."

The Massachusetts Legislature in 2024 passed a law requiring electric distribution companies to enter long-term contracts for 5,000 MW of energy storage by mid-2030, including 3,500 MW of mid-duration storage (between four and 10 hours), 750 MW of long-duration storage (between 10 and 24 hours) and 750 MW of multiday storage (greater than 24 hours).

The RFP is intended to procure projects "that have a strong likelihood of being financed and constructed and that will provide a reliable and cost-effective source of beneficial, reliable energy storage systems to the commonwealth," the DOER and the utilities wrote.

In the first solicitation, the state seeks only to procure the environmental attributes associated with storage projects. This includes credits for the state's Clean Peak Standard, which incentivizes emissions reductions during peak demand periods.

The bid submission deadline is noon on Sept. 10. Bidders are allowed to propose projects at or above 69 kV that can supply between 40 and 1,000 MW and can propose long-term contracts running through the end of 2050.

The RFP requires projects to have a scheduled in-service date earlier than Jan. 1, 2030, and directs each bidder to "demonstrate that its proposal can be developed, permitted, financed and constructed within a commercially reasonable time frame."

Projects must commit to achieving capacity interconnection rights and qualifying for the ISO-NE capacity market. The RFP requires bidders to "include a realistic and specific plan to implement any transmission system upgrades or other work anticipated to be needed to achieve CCIS-equivalent interconnection."

Developers also must provide a non-refundable bid fee of $500/MW of proposed nameplate capacity, which is intended to cover the cost of evaluation.

Projects will be evaluated based on quantitative and qualitative criteria. They will be graded on a 100-point scale, with 80 points for direct and indirect costs to ratepayers and 20 points for qualitative factors, including project viability, climate and environmental benefits, grid reliability and resilience effects, and stakeholder engagement.

The DOER, working with an independent evaluator, will select winning bids. The utilities will be responsible for executing contracts, which will be subject to the approval of the Massachusetts Department of Public Utilities.

The DPU approved the procurement framework in late July, writing that it "represents a reasonable balancing of interests and demonstrates progress toward achieving the commonwealth's statutory energy storage systems requirement as well as seeking to contract for low-cost energy storage systems."

Under the current solicitation timeline, winning bids are to be selected by Dec. 9, and long-term contracts are set to be executed by March 27, 2026. ■

Why This Matters

Clean energy advocates in New England have expressed hope that state incentives and procurements will help mitigate the increased federal policy headwinds against energy storage.

NEPGA Seeks Relief for 'Improper' Pay-for-Performance Costs in ISO-NE

Group Contests Penalties Generators Incurred During June Emergency Event

By Jon Lamson

The New England Power Generators Association (NEPGA) is seeking immediate action from FERC to address what it calls "serious flaws" in the design of ISO-NE's Pay-for-Performance (PFP) mechanism, which the group says caused capacity resources to face $51 million in "improper charges" incurred during a capacity shortfall event June 24.

In a complaint filed with FERC in late June, NEPGA wrote that resources with capacity supply obligations (CSOs) were required to provide power above their obligations and that capacity resources that performed during the event were charged millions to make up for the under-collection of penalties on resources that failed to perform (*EL25-106*).

The association argued that imposing expensive PFP charges on resources that fulfill their capacity supply obligations undermines performance incentives and could dissuade resources from participating in future capacity auctions.

ISO-NE's PFP mechanism is intended to incentivize resource performance during capacity shortfall events. Resources that provide more than their CSO receive PFP credits, while resources that receive less than their obligation face PFP charges. Resources that lack CSOs can also receive payments by providing power during shortfall events.

Why This Matters

NEPGA argued that the existing rules unfairly impose costs on generators that fulfill their capacity supply obligations, and said immediate changes are needed to prevent similar costs from being incurred during future capacity deficiency events.

The Mystic Generating Station in Everett, Mass. | *Constellation*

The system is intended to insulate ratepayers from the direct effects of charges and credits, with the charges for under-performers directly correlating with the payments to over-performers. To prevent resources from facing excessive penalties due to an outage, the PFP mechanism includes stop-loss provisions capping the total cost of penalties a capacity resource can incur each month.

ISO-NE's PFP rules have undergone multiple changes in recent years, and on June 1, the RTO increased the PFP rate from $5,455/MWh to $9,337/MW-hour.

NEPGA wrote in its complaint that the PFP balancing ratio — which sets the portion of each CSO that resources are required to meet in an event — surpassed 1.0 on June 24 due to higher-than-expected load that exceeded the amount of obligated capacity. (See *Extreme Heat Triggers Capacity Deficiency in New England*.)

The association noted that the balancing ratio averaged 1.031 over the three-hour emergency period June 24. NEPGA said this rate would have cost a perfectly performing 500-MW resource nearly $500,000 over the three-hour period and estimated the elevated balancing ratio "caused $25 million in improper charges to capacity resources" during the event.

"Even suppliers that had delivered 100% of their promised supply obligation now faced charges under ISO-NE's rules and a large number of resources reached their monthly stop-limit," NEPGA wrote.

Quoting from the movie "This Is Spinal Tap", NEPGA stressed that "generators cannot give 110%. It is as certain as amplifiers not being capable of 'one louder' even if 'these go to 11.'"

NEPGA also wrote that the RTO's stop-loss rules led to the significant under-collection of PFP payments, which was charged to capacity resources which had not hit the stop-loss limit.

"Capacity resources that did not reach their monthly stop-loss limit were charged an additional $26 million to make up the negative net surplus of capacity performance payments," NEPGA said. It noted the PFP balancing fund also included $9 million in excess revenue caused by reserve shortages, which partly offset the under-collection of charges, reducing the balancing fund's deficit to $17 million.

When accounting for the offsetting costs, "the ISO-NE tariff charged capacity resources — including fully performing capacity resources — to recover this $42 million to provide maximum $9,337/MWh bonuses to resources performing above their capacity supply obligation," the association wrote.

'Careful Evaluation'

To address the issue, NEPGA proposed to "cap the balancing ratio at 1.0 and split the bonus pool that gets collected to pay over-performers, with no post-hoc secondary charges imposed on capacity supply obligation holders to make up for any under-collection."

NEPGA wrote that these changes would mirror the PFP rules at PJM and noted that FERC in 2015 required PJM to impose a cap on its balancing ratio.

The proposed changes would "adjust bonus payments to performing resources while still sending very strong financial incentives to perform during emergencies," NEPGA wrote, adding that the changes would "ensure that the capacity market sends incentives to take on a capacity supply obligation."

NEPGA requested that FERC "set an immediate refund effective date" on the date of the complaint, noting that similar issues could occur before the end of the summer.

In a filed response to NEPGA's complaint, ISO-NE opposed NEPGA's request for fast-track processing of the complaint, arguing the association failed to justify the need for immediate action. The RTO wrote that the complaint raises "complex questions" about the design of the PFP mechanism that are not well suited for fast-track processing.

The RTO did not substantively comment on NEPGA's proposed remedies, but wrote it is "misleading" to say the issues could be easily and quickly resolved by the proposed changes.

"PJM's version of pay-for-performance differs from New England's version in important ways," ISO-NE wrote, noting that PJM uses separate PFP rates for payments and charges, while ISO-NE uses a single rate.

"A single performance payment rate that provides the same marginal incentive to perform is central to [ISO-NE's] two-settlement, pay-for-performance market design," ISO-NE wrote. "Transitioning to separate payment rates requires careful evaluation to ensure that it does not produce gaming opportunities."

ISO-NE also asked FERC to extend the deadline for responses to the complaint from Aug. 14 to Aug. 21, which the commission granted Aug. 5. The RTO said the extension is necessary to "provide the commission with a clearer indication of the full range of issues that are implicated." ■

MISO Requests Month to Respond to States' Long-range Tx Complaint

By Amanda Durish Cook

MISO has asked FERC for a month to prepare a defense of its second long-range transmission portfolio, which is being challenged by five state commissions in the footprint.

The grid operator *said* it needed an extension to respond to the 200-page complaint alleging that its $22 billion transmission package for the Midwest region isn't as valuable as purported. As it stands, MISO is to respond to the complaint, filed July 30 by the public service commissions of North Dakota, Montana, Arkansas, Mississippi and Louisiana, by Aug. 19. The RTO asked for the deadline to be pushed to Sept. 19. (See *Five Republican States File FERC Complaint to Undercut $22B MISO Long-range Tx Plan*.)

MISO said it didn't receive notice from the commissions that they planned to dispute the transmission portfolio. It also said it needed time to review testimony, conduct analyses and prepare its own expert witness testimony in response to testimony from William Hogan, research director of the Harvard Electricity Policy Group and professor emeritus at the John F. Kennedy School of Government at Harvard University.

Hogan testified that MISO's assumptions and cost-benefit analysis "contain several significant defects," including environmental benefits extended to states that don't believe there is a social cost of carbon; reliability benefits premised on unlikely instances of load shedding as the alternative at a rate of $3,500-$10,000/MWh; and a distorted avoided capacity cost benefit that doesn't imagine materially different and closer-to-load generation resources being built without the transmission projects. The criticisms track those that MISO's Independent Market Monitor made in 2024. (See *MISO Board Endorses $21.8B Long-range Transmission Plan*.)

The Bottom Line

MISO said it needs until Sept. 19 to conduct analyses and prepare its own expert witness testimony in response to a five-state complaint seeking to unravel its $22 billion long-range transmission plan.

Hogan also said he took issue with the 29.8 GW of high-accreditation "flex capacity" MISO assumed would be built by 2042 to meet resource adequacy requirements despite no concrete plans from members. Hogan said if members built the nearly 30 GW in highly available capacity, it would obviate the need for scores of wind and solar generation projects MISO also assumed in its modeling.

MISO has said repeatedly that its second long-range portfolio is founded on the generation plans that its members have communicated to it. The RTO also noted that 75% of the footprint's load is served by members with ambitious decarbonization or renewable energy goals.

The five state commissions asked FERC to deny MISO's request for extension. They argued that MISO's subject matter experts are in-house and "MISO should have on hand all the materials to support its case, primarily the package of information it presented to receive the board's approval."

They also said the filing should come as no surprise, because every concern they outlined with the transmission portfolio was raised multiple times by stakeholders, some state commission staff and MISO's own Independent Market Monitor as the portfolio was being drawn up.

"MISO had ample time to respond to those concerns but failed to substantively address them," the five state commissions said.

The states added that should FERC decide to grant an extension, it should be limited to two weeks beyond Aug. 19.

The North Dakota Public Service Commission — one of only two state commissions that joined the complaint that are expected to fund some of the long-range transmission — circulated a press release explaining that ballooning transmission costs drove their decision to draft the complaint.

A completed substation as part of the Cardinal-Hickory Creek line in Wisconsin | *ITC and ATC*

"Transmission costs are rapidly becoming a large portion of utility customer bills, and their costs need to be carefully scrutinized," Commissioner Jill Kringstad said. "I recognize the importance of transmission infrastructure, but it must be a prudent investment that balances affordability with the long-term needs of the grid."

Commission Chair Randy Christmann said MISO gave a "weak justification" for the projects and that they will lead to "massive cost increases for residents."

"Overturning MISO's decision will protect North Dakotan consumers from this egregious maneuver," he said.

Commissioner Sheri Haugen-Hoffart said she opposes "any cost allocation framework that compels states to subsidize transmission projects driven by other states' public policy goals."

"If a state chooses to pursue ambitious decarbonization targets, it should also bear the financial responsibility for the infrastructure required to meet those goals. Anything less undermines the principle of just and reasonable rates and imposes unfair financial burdens on ratepayers in states that have not adopted such policies," Haugen-Hoffart said. ■

MISO, SPP Still on Hunt for Joint Transmission Under CSP

By Amanda Durish Cook

MISO and SPP appear undaunted in their pursuit of a beneficial interregional project after FERC's rejection of exemptions to their joint study rules.

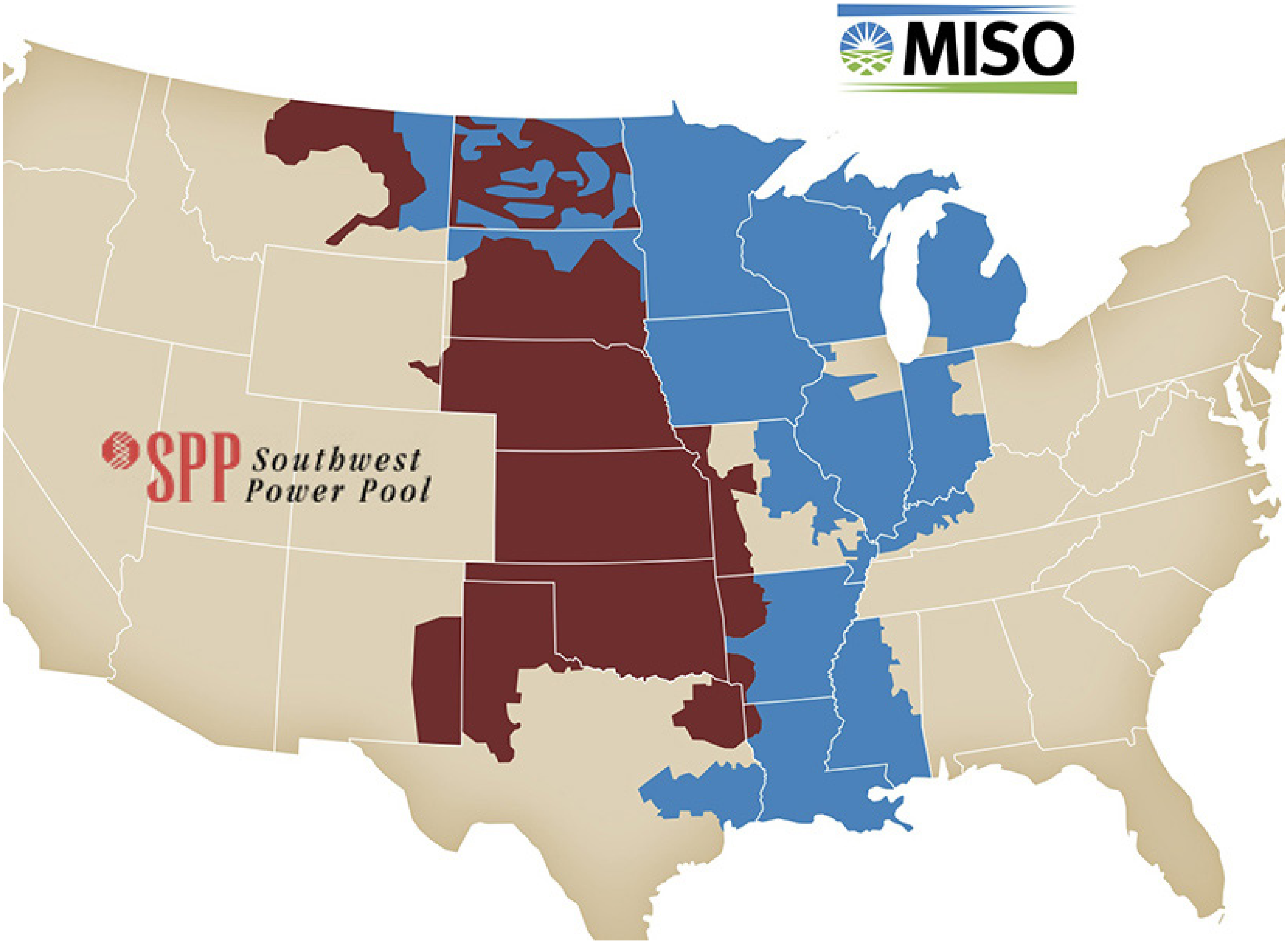
The grid operators announced they are still in search of projects that improve resilience, reliability and transfer capability under their joint Coordinated System Plan (CSP) study process. They also said they are weighing proposing more benefit metrics to FERC to justify projects.

The RTOs originally set out to perform a different type of CSP this year with more in-depth modeling on a 10-year horizon and a wider variety of benefits that they said would have cast a wider net for projects. However, FERC in July denied their requested temporary exemptions. The commission said a limited waiver of requirements was not the best vehicle for changes to the study. (See *FERC Denies MISO, SPP Waiver of Joint Study Process*.)

Now the RTOs say they are considering submitting a filing to FERC under Federal Power Act Section 205 to include more types of benefits in business cases for joint projects. They said drawing on more and different benefits is in line with FERC Order 1920, which laid out seven categories of transmission benefits.

What's Next

MISO and SPP said they may pursue a new FERC filing to allow them to use a wider range of benefits when making a case for interregional transmission. Currently, the RTOs may only consider the cost of avoided regional projects when evaluating possible interregional projects.



MISO and SPP's territories | *MISO and SPP*

MISO and SPP's joint operating agreement currently limits them to using only the value of avoided regional projects to measure the reliability and public policy benefits of interregional projects stemming from the CSP.

The two grid operators have said measuring the reliability value of a project solely on its ability to avoid regional projects constricts their planners from analyzing projects' usefulness in other areas, like expanded interregional transfer capability or fortification against weather extremes.

During an interregional planning meeting Aug. 6, SPP Manager of Interregional Strategy and Engagement Clint Savoy said the RTOs would have more details on how the two might expand their benefit definitions under the CSP during the next joint meeting Oct. 24.

"It's something that we're constantly talking about … how to approach changes we want to make to the process itself," Savoy told MISO and SPP stakeholders.

The RTOs also said that because FERC rejected the waiver, they will add 15-year-out modeling scenarios to this year's CSP.

The JOA requires MISO and SPP, when conducting a CSP, to use multiyear modeling, which the RTOs interpret to mean using multiple model years, such as five, 10 or 15 years out. They initially wanted to model several different 2034 scenarios to land on transmission needs instead of studying the system at different points in time.

MISO Interregional Planning Adviser Ashleigh Moore said 15-year models are in progress and would be complete in October or November.

Moore said that if transmission needs prove to be "drastically different" with the addition of the 15-year-out modeling, the RTOs might open a second window for stakeholders to propose transmission solutions. MISO and SPP are currently accepting transmission project ideas for the CSP through Sept. 5 under their first submission window.

The RTOs are still aiming for a "robust and comprehensive interregional planning process," she said.

SPP engineer Spencer Magby said the RTOs will model an extreme temperature scenario that will serve as a sensitivity to the study. However, the modeling would only extend to extremely low winter temperatures, not blistering high summer temperatures.

Southern Renewable Energy Association Transmission Director Andy Kowalczyk said MISO and SPP should probably model systems stressed by summertime, especially given the springtime instances of load shedding in Louisiana for both RTOs. (See *MISO Says Public Communication Needs Work After NOLA Load Shed*.)

MISO and SPP planning engineers said they might consider hot weather modeling additions.

Missouri Public Service Commission Chief Utility Economist Adam McKinnie asked MISO and SPP to share data on their existing transfer limits so stakeholders can have a better idea of how projects could expand transfer capability. Engineers said they would consider the request.

MISO and SPP said they would share draft transmission projects in October and prepare to make project recommendations in December. As for cost allocations of the projects, the RTOs plan to hold discussions on a cost-sharing design late in 2025 and over 2026.

MISO and SPP's CSP process has never produced a viable interregional project. Their Joint Targeted Interconnection Queue study, on the other hand, has culminated in $1.7 billion in projects to be funded by the interconnecting generation that benefit from the lines.

Additionally, MISO and SPP aim to submit a proposal to FERC next year to institute the smaller, congestion-relieving Targeted Market Efficiency Projects, with a similar process to MISO and PJM's TMEP studies. ■

MISO Stakeholders Move to Enshrine Conduct Rules in Governance Guide

By Amanda Durish Cook

MISO stakeholders have adopted the spirit of MISO's new code of conduct into their comprehensive rulebook while adding rules that empower committee chairs to shut down rude behavior or order attendees out of conference rooms.

MISO's Steering Committee voted to include rules similar to MISO's code of conduct in the Stakeholder Governance Guide at an Aug. 5 meeting.

A draft *version* of the guide now provides a "Respectful Conduct in Stakeholder Meetings" section that calls for "a foundation of mutual respect, professionalism, fair debate and dialogue." It details a zero-tolerance policy for name-calling, sarcastic comments, demeaning remarks, repeated interruptions and disruptive behavior. MISO's code of conduct, introduced in early July, similarly forbids rude or callous language, deliberate meeting disruptions or disregarding committee chairs' instructions. (See *New MISO Stakeholder Code of Conduct Forbids Rude or Callous Language*.)

MISO Reliability Subcommittee Chair Ray McCausland, of Ameren, said while MISO published its own conduct rules, the list to be included in the Stakeholder Governance Guide is written by stakeholders and considered separate from MISO's. The MISO Code of Conduct is set to be included in an appendix to the Stakeholder Governance Guide.

Steering Committee Chair and ITC's Brian Drumm said stakeholders can think of the code as a notice to be on their "best behavior."

A MISO Advisory Committee meeting in March in New Orleans | © *RTO Insider*

The guide's more detailed language that largely tracks MISO's code replaces years-old and less specific conduct language that laid out MISO's grounds for stakeholder removal due to abusive or disruptive behavior. The new insert goes a step further than MISO's new code and confers responsibility on committee chairs and vice chairs to quell unruly meetings.

The guide says chairs and vice chairs can:

- Call a meeting participant to order "immediately upon a breach of decorum."
- Warn an individual about consequences for continued disruptions.
- Refuse to recognize a participant "until order is restored."
- Order a participant to leave for the remainder of a session.
- Initiate disciplinary procedures, "which may include formal censure, suspension or removal from the stakeholder group."

"These rules exist, not to silence disagreement, but to preserve a space where all voices can be heard without hostility or harassment," the guide's draft wording concludes.

Market Subcommittee Chair Tom Weeks, of the Michigan Public Power Agency, said while he supports "civil and professional discourse" in meetings, he's heard concerns from stakeholders that the code and accompanying guide changes could stifle conversation because some stakeholders' points might be perceived as intimidating. He said while he didn't oppose the new wording, stakeholders' concerns are not "overblown."

"We don't want to swing the pendulum to the other side where people don't feel free to make substantive comments," Weeks said. He asked stakeholders to keep in mind that some stakeholders can deliver comments with more passion and enthusiasm than others.

The revisions concerning conduct were part of a larger batch of edits to MISO's Stakeholder Governance Guide, which is altered as stakeholders deem necessary. The Steering Committee either adopted suggested edits and sent them along for final review from MISO's Advisory Committee or determined that certain changes needed more refinement and sent them back to the Stakeholder Governance Working Group, which drafted the changes.

The Steering Committee did not approve another edit to the guide that would have allowed MISO itself to present motions during stakeholder meetings. Some questioned the appropriateness of MISO raising voting motions.

McCausland said the intent of the change was to spell out that MISO could introduce a motion but that a stakeholder is required to move such a motion to the floor for a vote. Some Steering Committee members said the wording wasn't clear, and the committee ultimately sent the item back to the working group for revision. ■

Why This Matters

MISO stakeholders have followed MISO's lead and are close to adopting new meeting conduct rules in their governance guide.

NYISO Stakeholders Concerned About Lack of Data on Supplemental Commitments

By Vincent Gabrielle

Stakeholders requested that the NYISO Market Monitoring Unit provide a comprehensive explanation of the difficulties in obtaining data from the ISO and market participants on supplemental commitments after it presented its State of the Market *report* for the first quarter Aug. 5.

Supplemental commitments to satisfy reserve requirements occurred on 75 days in the first quarter in the North Country load pocket — near the border with Canada — and 28 days in New York City load pockets, according to the MMU's presentation to the Installed Capacity Working Group. Nearly half of these commitments could not be verified by the MMU.

"These are instances where we weren't able to get information to substantiate the need for the commitment," said Pallas LeeVanSchaick, vice president of Potomac Economics.

A supplemental commitment is an out-of-market action in which a generator is not committed economically in the day-ahead market but is needed for reliability. Transmission owners and NYISO operators may dispatch generators "out of merit order" to maintain lower-voltage reliability and manage constraints in high-voltage transmission that are not represented in the market model.

Stakeholders pointed out that this was a repeat issue for the MMU and asked whether there was a provision in the tariff or a technical issue that was preventing the MMU from obtaining the information. LeeVanSchaick said the data from the ISO are not detailed enough to make a determination in all cases.

Stakeholders also asked whether the MMU was able to ask transmission owners and generators for information. LeeVanSchaick said that while it can ask any market participant for information, the kind of information is different depending on what kind of participant it is.

"I don't think it's a matter of asking the MMU to identify who the bad guy is, so much as … providing more information about the … different rules and responsibilities for information requested from generators, the NYISO, TOs and other parties," a stakeholder who did not identify themselves said. "Understanding that at a general level could show what the barrier to receiving information might be."

Competitive and Congested

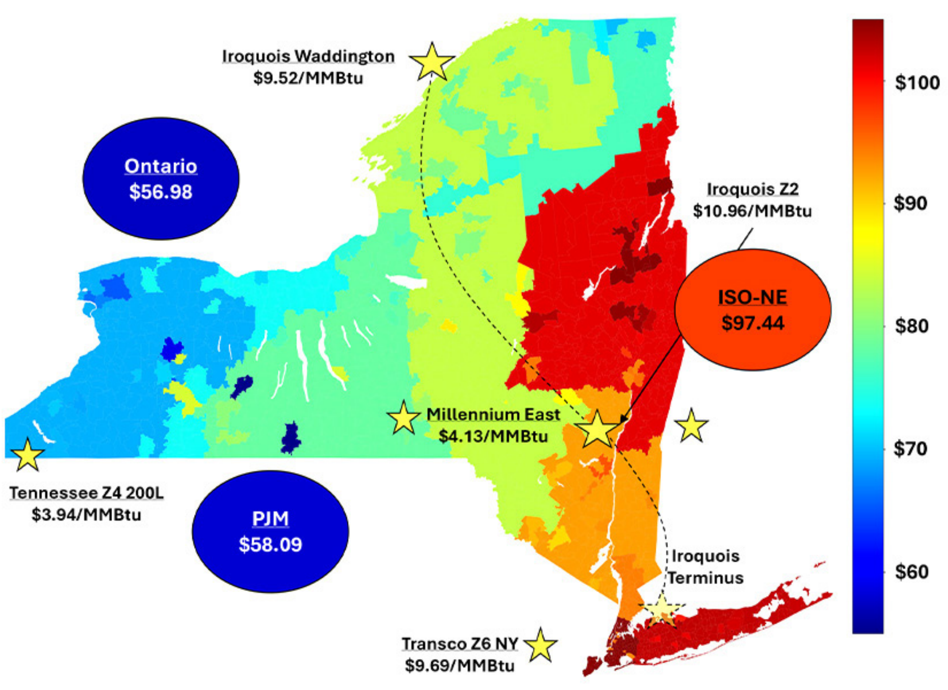
The NYISO markets otherwise performed competitively, the MMU said. Prices in each region were up year-over-year this quarter, ranging from 59 to 119%, mostly driven by higher natural gas prices, which rose 67% in Western New York and 188% along the border with Vermont. LeeVanSchaick said that this was from the extremely cold weather in January and February.

Load levels were higher across the state compared to 2024. The average daily load increased 4.5%, and the peak load increased by 3.4%. At the same time, congestion rose within the state and across the PJM-NYISO interface. This was partly because of transmission outages in New York but also from high demand.

Thirty percent of the congestion occurred in New York City, increasing 450% year over year. The Gowanus-Greenwood line was out of service throughout the quarter, and a parallel line was out of service in February.

Many generators were curtailed or out of service. During the coldest part of January, roughly 1.75 GW of oil generation was out of service because of planned outages. "As NYISO implements firm-fuel capacity accreditation in 2026/27 and designs a seasonal capacity market, it will be important to consider reasonable limits on planned outage scheduling under peak conditions and incentives for availability," the MMU said.

NYISO and local TOs issued 28 GWh of wind curtailments manually because of unmodeled transmission constraints or generators not responding to economic curtailment instructions. The MMU found that TO-controlled communication equipment was not maintained well enough to send signals from NYISO to the control centers of many wind plants. It suggested implementing stronger penalties for failure to comply with curtailment instructions. ■



System price diagram | *NYISO*

Pa., Va. Governors Float Clements, Christie as PJM Board Candidates

By Devin Leith-Yessian


Former FERC Commissioner Allison Clements | © RTO Insider

Pennsylvania Gov. Josh Shapiro (D) and Virginia Gov. Glenn Youngkin (R) have requested that PJM consider former FERC Commissioners Mark Christie (R) and Allison Clements (D) to fill two vacant seats on the RTO's Board of Managers.

"Last month, we joined seven of our fellow governors in urging PJM to begin to restore purpose and vision for the organization, independent from the wishes of any particular sector, by tapping nationally respected leaders to fill the two vacant board seats," the governors wrote in a *letter* to the RTO on Aug. 11. "That diverse group of governors strongly urged PJM to appoint a bipartisan slate of energy luminaries: recently retired FERC Chairman Mark Christie and former FERC Commissioner Allison Clements."

Nine governors signed onto a July 16 *letter* to PJM calling for a process for states to nominate candidates to the board and requesting a meeting with the RTO's Nominating Committee. Virginia Energy Director Glenn Davis attended the Members Committee's meeting to reiterate the governors' concerns, saying they had candidates in mind. (See *State Governors Seeking Ability to Nominate 2 Members to PJM Board*.)

"Christie and Clements are widely respected leaders who understand the problems facing PJM and the region," Shapiro and Youngkin wrote. "They have the independence and know-how to chart a principled new direction for the organization. We believe their appointments will begin to restore transparency and accountability to decision-making at PJM."


Former FERC Chair Mark Christie | © RTO Insider

They argued that PJM's stakeholder process — with more than 1,000 voting members and requiring a supermajority for action — has resulted in a stalemate in recent years, requiring the Board of Managers to take unilateral action, which they suggested contributed to the ouster of two board members in May, including Chair Mark Takahashi. (See *PJM Stakeholders Vote Out 2 Board Members*.)

The nine governors are also seeking to create an association to engage in dialogue between their offices and PJM leadership. They are planning to hold a technical conference Sept. 23 at the National Constitution Center in Philadelphia to discuss "organizational and market reforms at PJM."

Shapiro and Youngkin wrote that failing to consider candidates recommended by the governors would undermine confidence in PJM's governance.

"As governors from different parties, we have points of disagreement on energy policy, but we are united by the need to get PJM back on track to fixing the problems we collectively face," they wrote. "By working together with a diverse, bipartisan coalition of governors, we are committed to solving these collective problems, and to ensuring that the citizens of our states and the region receive the affordable, reliable power that they deserve."

Christie left FERC on Aug. 8 after serving for more than four years, including being chair since Jan. 20. (See related story, *FERC Chair Mark Christie Leaves Agency After One Last Dissent*.)

Clements served from late 2020 until June 30, 2024, when she was replaced by Commissioner Judy Chang. (See *Senate Confirms Chang as Clements' Replacement on FERC*.) She now works as a senior adviser for the consultancy Capstone, as a partner with digital infrastructure advisory firm ASG and as principal of *804 Advisory*.

Neither could be reached for comment by press time. ■

Why This Matters

Christie and Clements are the first candidates to be publicly named by any of the governors calling for a process for the states to nominate candidates to the PJM board.

PJM Board Initiates CIFP Addressing RA and Large Loads

By Devin Leith-Yessian

The PJM Board of Managers has initiated a Critical Issue Fast Path process aimed at maintaining resource adequacy in the face of rising data center load growth, asking stakeholders to draft proposals to serve 32 GW of load growth expected by 2030.

"Recent increases in large load additions, mainly from data centers, present both opportunities and challenges for the regional grid," the board wrote in an Aug. 8 *letter* announcing the initiation of the CIFP process. "PJM's location, size, market opportunities and system reliability make it an attractive area for large load customers to locate, and we continue to see significant load interconnection activity at several of our utilities." The board cited PJM's 2025 *load forecast*, which estimates the system's peak load will grow by 32 GW between 2024 and 2030, with 30 GW of that being attributed to data centers.

The letter identifies five areas for stakeholders to focus on: resource adequacy; reliability criteria for triggering any solutions with a temporary nature; changes to interconnection rules that may support resource adequacy; coordination between PJM, those party to large load contracts, member states and impacted customers; and a timeline for implementing solutions for the 2028/29 Base Residual Auction (BRA). The letter states the process will inform the contours of a proposal the board intends to file at FERC in December. The process will begin with a pre-CIFP workshop Aug. 18.

The letter raises the possibility of adjusting the load used or cleared in BRAs if it's not capacity-backed. It also encouraged improvements to existing resource adequacy tools, such as demand response

Why This Matters

The PJM Board of Managers aims to head off potential reliability impacts that accelerating data center load growth may have on reserve margins.

PJM Board of Managers Chair David Mills | © *RTO Insider*

or the ability for load to bring its own generation. Solutions also are encouraged to be market-based and could be either permanent, transitional or a combination of the two.

Changes to the rules for resource interconnections could allow new entries to meet some of the expected load growth. The board's letter states that the 2022 shift to a cluster-based process for studying new service requests and allocating network upgrade costs has cleared more than 140 GW of resources in the queue, 46 GW of which have entered interconnection agreements with the RTO. The remaining queued resources are expected to be processed over the next 18 months. An additional 11 GW was added through the Reliability Resource Initiative.

Despite faster completion of interconnection studies, the board wrote that many of those projects have run into siting, permitting and supply chain challenges inhibiting their ability to enter commercial service.

This is the second CIFP focused on resource adequacy and capacity market design the RTO has initiated in recent years, with a February 2023 *letter* opening a process to address unrecognized reliability risks and the impact that "significant load growth" paired with generation deactivations outpacing new entry could have on "a healthy reserve margin."

That resulted in two FERC filings, one the commission approved to rework PJM's resource testing requirements, risk modeling and accreditation, while it rejected a second to revise the capacity performance penalty structure. (See *FERC Approves 1st PJM Proposal out of CIFP* and *FERC Rejects Changes to PJM Capacity Performance Penalties*.)

Another CIFP process was conducted in June 2025 to determine how to allocate the cost of keeping Constellation Energy's two gas-fired units at the Eddystone Generating Station online under a Department of Energy emergency order. (See *PJM Board Initiates CIFP Process for Eddystone Compensation*.)

In the Aug. 8 letter, the board said a poll of stakeholder priorities found support for addressing the reliability risks posed by large loads in particular. The *results* were presented at the July Members Committee meeting. (See "PJM Presents Capacity Market Feedback Poll," *PJM MRC/MC Briefs: July 23, 2025*.)

"A recent survey of PJM members and

Continued on page 39

N.J. Confronts Data Center Load Surge

Conference Speakers Say Risk vs. Cost Analysis Will be Key

By Hugh R. Morley

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.

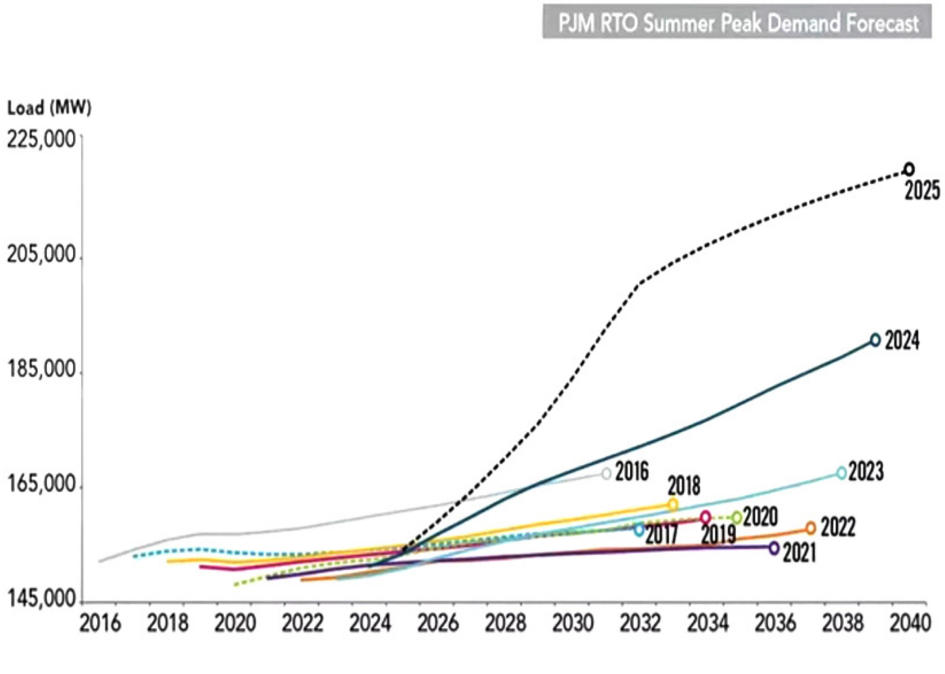
"These things bring very unique and significant challenges to both the planning and the operation of the bulk power system."

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*

Why This Matters

The shifting demand profile has added to the importance of getting forecasts correct. The highest peaks are now in the winter, in which consequences of a blackout are most dire.

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."

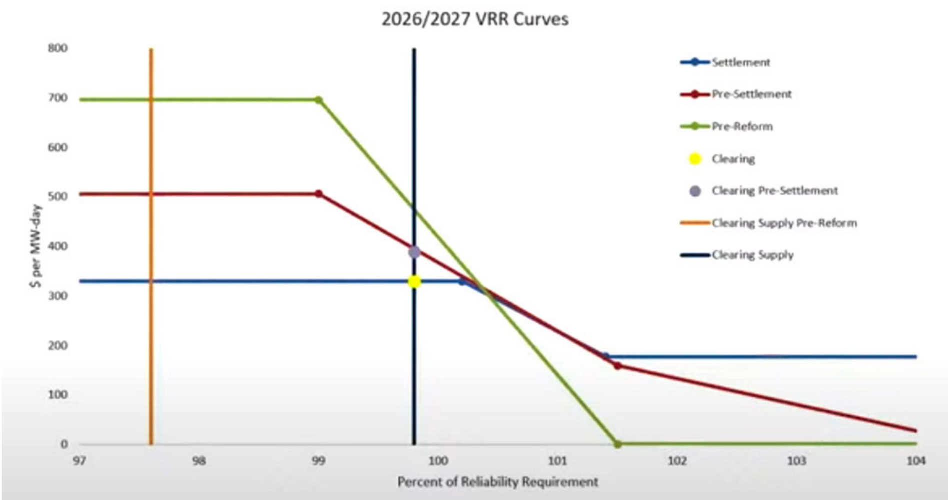
Yet the unique element of hyperscalers, the largest data centers, makes that difficult, said Tom Rutigliano, senior climate advocate for Natural Resources Defense Council.

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." ■

PSEG Sees Data Centers Surge amid Rising Demand Forecasts

Utility Looks to N.J. for Steps to Combat Future Shortfall

By Hugh R. Morley

The Public Service Enterprise Group is waiting for New Jersey to address the region's predicted energy shortage as the utility sees a dramatic rise in potential demand from data centers, said CEO Ralph LaRossa.

Developer inquiries for large load projects seeking new service connections jumped by 47% between March and June to 9,400 MW, LaRossa said Aug. 5 during the company's second-quarter earnings conference call.

There's growing concern in New Jersey and in other states that the PJM region is facing a chronic future energy shortage. Rapid demand growth is happening while aging fossil fuel plants are closing faster than new generators, mostly renewable energy, can open.

"The resource adequacy challenges in New Jersey and across the entire 13-state PJM region are becoming more acute," LaRossa said. "Recent reports reflect an increasing amount of new large load applications that are quickly eroding existing reserve margins. Within the confines of PJM, it's hard to see the path to new generation through existing market signals, which may require the consideration of a new approach to procuring capacity and resource planning."

Underscoring the seriousness of the situation, LaRossa said the utility hit a peak load of 10,229 MW during the three-day heat wave in June, the highest level since 2013. New Jersey, a net importer of power, imported about half its energy during the heat wave, LaRossa said. But while the state in the past could rely on energy imports from other PJM members that generate excess power, such as Pennsylvania, that "convenient option is quickly being absorbed by rapid growth of native load in those states," he said.

PSEG's Hope Creek and Salem nuclear plants | *PSEG*

Why This Matters

New Jersey, a net importer of power, imported about half its energy during the recent heat wave. But other PJM member states that generate excess power, such as Pennsylvania, are seeing their excess energy being absorbed by rapid growth of native load.

Much of the new demand is for large-load projects, mainly data centers used for artificial intelligence and other projects. LaRossa said about 90% of the 9,400 MW in large load projects — which include mature applications, feasibility studies and initial leads — comes from planned data centers. He said he expects 10 to 20% of the total to be completed eventually.

One of the projects included in the large load figure is a data center that AI cloud computing company CoreWeave plans to build on a *107-acre campus* in Kenilworth, N.J., LaRossa said. CoreWeave announced Aug. 4 it has completed the land purchase.

Capacity Auction Concerns

The earnings call was PSEG's first since PJM completed its capacity auction and announced on July 22 the outcome price of $329.17/MW-day (UCAP) RTO-wide for delivery year 2026/27. The price would have been $388.57/MW-day without a price cap put in place by PJM in agreement with Pennsylvania Gov. Josh Shapiro (D). He filed suit seeking changes in the system after the auction in 2024 raised prices about tenfold 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*.)

The dramatic hike in the last capacity auction triggered widespread concern among officials in New Jersey and other states for its impact on ratepayers. The average electricity bill in New Jersey increased by 20% on June 1.

LaRossa said the company anticipates "a near-flat impact on customer electric bills" from the recent auction when it is factored into the state's Basic Generation Service rates that will take effect June 1, 2026.

In the longer term, one measure that would help the state increase its generating capacity is a bill, *A5439*, that would allow electric public utilities to own and operate electric generation facilities, LaRossa said.

"In New Jersey, policymakers have begun to actively weigh the priorities of economic growth with system reliability and affordability and the state's environmental policies," he said.

PSEG is pushing the state to address some key issues, he said: "What are the forecasts they're looking for? What are the reliability outcomes they're targeting? What are the affordability targets they have? And then finally, the environmental policy goals. When you put those four pieces together, we think we'll be able to find the right answer and solution for the state."

However, he said PJM's capacity process, especially its governance, needs reform, echoing concerns expressed by other critics of the RTO.

"We've been very vocal about that for many years," he said. "We don't think that it is attracting additional generation. … The facts are that there has not been any new base load generation built in New Jersey for quite some time."

"The governance at PJM doesn't allow for a lot of the things that people are talking about to just be unilaterally implemented," he said, citing the example that for state governors to get involved in the process, PJM members must give a vote of approval. "This governance process is the core problem."

Nuclear Advances

LaRossa said PSEG is taking steps to enhance its nuclear power generation, noting that an enhancement project at the Hope Creek Generating Station nuclear facility operated by the company in Salem, N.J., will add 200 MW. He characterized the enhancement, which is expected to go online between 2027 and 2029, as "the size of a small modular creator of incremental, carbon-free, dispatchable power."

He said the company also will benefit from the recent federal funding bill, which continued the production tax credits for nuclear facilities and extended depreciation rules that will help PSEG's nuclear fleet.

PSEG's second-quarter results for 2025 grew from $434 million ($0.87/share) in 2024 to $585 million ($1.17/share). Non-GAAP operating earnings for the quarter were $384 million ($0.77/share) in Q2 2025, compared with $313 million ($0.63/share) in the same period last year. ■

PJM Initiates Load Shed in Baltimore Region After Substation Disconnect

By Devin Leith-Yessian

PJM initiated a load-shedding event Aug. 11 in the Baltimore Gas and Electric (BGE) region after the Brandon Shores substation went offline.

A PJM announcement states that the substation "experienced an unplanned disconnection" in the morning, after which transmission capability into the region was limited for much of the day and consumers were asked to conserve energy.

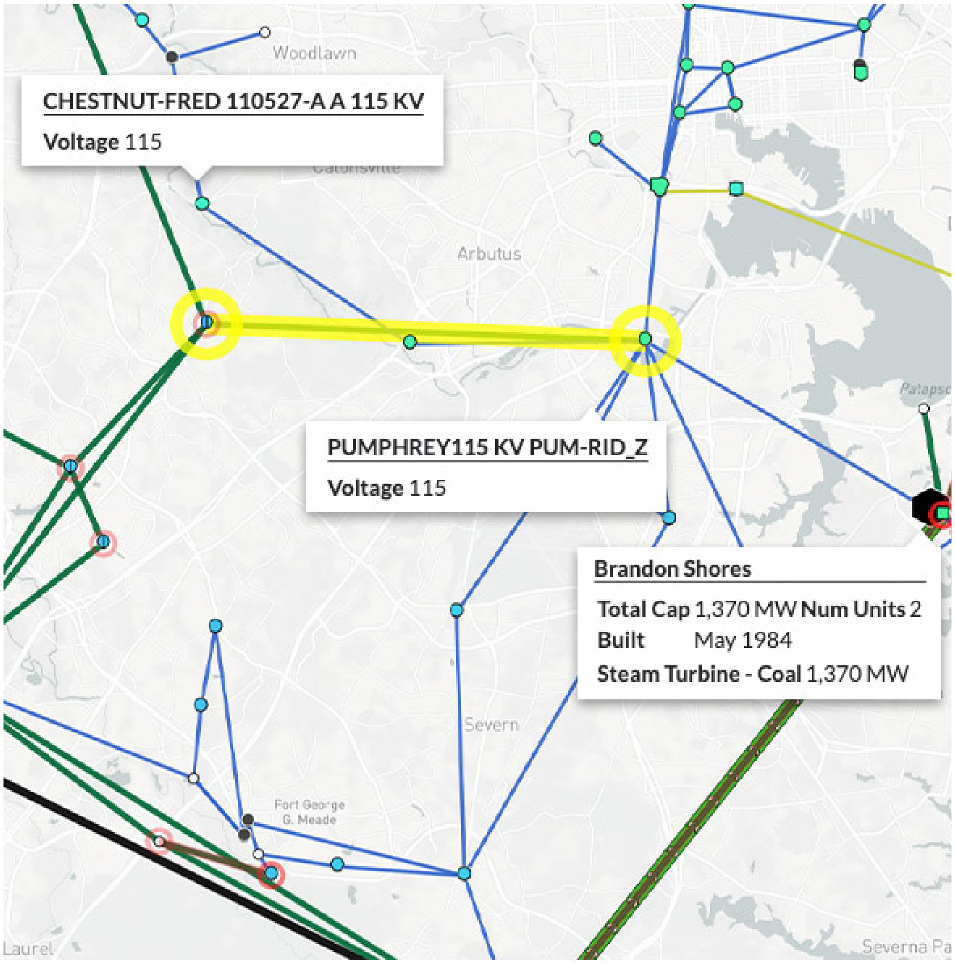
A voltage reduction action was initiated at 2:15 p.m. followed by a load-shed directive at 3:52 p.m. PJM's emergency procedure *page* states that the directive was initiated due to an N-5 cascade risk identified on the Chestnut-Fredrick Road 115-kV line in BGE. The load-shed directive lasted 28 minutes, ending at 4:20, while the voltage reduction ended at 5:09.

"While BGE worked to address the transmission outage, electricity demand briefly exceeded the current capacity of the local transmission system as demand peaked in the afternoon. To prevent damage to equipment and the risk of cascading outages across a broader area, at 3:52 p.m. Eastern, PJM directed BGE to lower flows across overloaded lines by reducing electricity load. BGE concurred and implemented its load-reduction plan, resulting in limited outages," PJM said in a notification to members.

Since the load shed was limited to BGE and did not extend to a full sub-zone, a performance assessment interval (PAI) was not initiated. PJM stated that some versions of its app incorrectly notified users of a PAI trigger.

BGE reported to PJM that transmission equipment that had been "inoperable" for much of the day had been brought back into service after the load-shed directive, allowing the action to be terminated. As of the 6:36 p.m. communication, some equipment still was offline.

"We expect that BGE will soon be returning to service those customers who were shed as part of our original directive. Continued reliable operation of the local transmission system will depend upon the operability of the transmission facilities that tripped this morning, but for now, the system is in a place such that we can serve our peak evening demand in the area," PJM said.



PJM directed a load shed in the Baltimore region on Aug. 11 to avoid a cascade condition on the Chestnut-Fredrick 115-kV line after the nearby Brandon Shores substation experienced an unplanned disconnect. | *Yes Energy*

The most recent load shed PJM had entered occurred on June 15, 2022, when storms damaged multiple transmission lines and put 200,000 customers along three 138-kV lines out of power. Following the December 2022 Winter Storm Elliott, PJM said it was one generation trip away from possibly having to implement a voltage reduction action. (See *PJM Orders Load Sheds in AEP Following Storms* and *PJM Recounts Emergency Conditions, Actions in Elliott Report*.)

Limited transmission capability in the Baltimore region contributed to the need for PJM to enter into a reliability-must-run (RMR) agreement with Talen Energy after it requested to deactivate its 1,289-MW Brandon Shores and the adjacent 843-MW H.A. Wagner generators.

Transmission violations identified with those units offline led to several transmission projects being added to the Regional Transmission Expansion Plan and a $180 million annual agreement to keep the two generators online.

The region also saw capacity prices surge above the rest of the RTO due to limited capability to import power from the rest of PJM. (See *FERC Approves $180M Annually for RMR Deals with Brandon Shores and Wagner Plants* and *PJM Market Participants React to Spike in Capacity Prices*.) ■

PJM PC/TEAC Briefs

Planning Committee

PJM Proposes Widening of Interim Deliverability Study Procedures

To increase energy supplies, PJM is *proposing* to expand its process for allowing new resources to inject onto the grid while their required network upgrades are being completed, allowing a unit to operate partially.

The proposal includes two issue charges to *rework* the interim deliverability study process and *expand* provisional interconnection service.

PJM Director of Interconnection Planning Donnie Bielak said the RTO's aim is to create a path for generators that fail interim deliverability studies but are able to inject some energy without causing network overloads, to operate as energy-only until they complete their full network upgrades. When an interim deliverability study identifies a local constraint impacting the ability for the resource to operate, an operational guide would be produced detailing the conditions under which dispatchers could use the unit.

Bielak said the impetus for the change is a surge in Energy Emergency Alert (EEA) Level 1 actions the RTO has initiated this year. The maximum generation and load management alert, the trigger for entering EEA-1, has been used 11 times in 2025, outnumbering all declarations since 2016.

"This is a pretty striking uptick in the use of this emergency procedure, which is only underscoring the need for more generation to be available to our control room," he said.

Under the proposal, the deadline for developers to request an interim deliverability study would be pushed back from July 31 to June 30 to provide staff with more time to complete the studies. Developers would continue to cover the cost of their administration.

Paul Sotkiewicz, president of E-Cubed Policy Associates, welcomed the change and said it should have been pursued earlier, but faulted PJM for advancing it through the quick-fix process, which allows an issue charge and solution to be voted on concurrently. He argued that the proposal cannot be made through manual revisions alone and would require tariff changes as well.

John Rohrbach, representing Southern Maryland Electric Cooperative, noted that, under PJM's rules, resources without a capacity commitment have no accompanying day-ahead and real-time energy market must-offer obligation, making their market participation voluntary — a point on which Bielak agreed.

Stakeholders Endorse Revisions to PJM Protection Standards

The Planning Committee endorsed *revisions* to Manual 07: PJM Protection Standards to add a section saying the circuit cases studies produced by PJM planning staff should not be used in isolation. The language recommends that generation owners (GOs) coordinate with the transmission owners (TOs) serving their points of interconnection, while TOs should coordinate with their neighbors.

The revisions also seek to expand relay communication requirements, add reporting open circuit conditions for station batteries and include additional detail on transformer high-side lead protection.

Relay Plans Endorsed

The committee endorsed a *proposal* to sunset the Relay Testing Subcommittee (RTS) and roll its work into the Relay Subcommittee (RS).

The revisions to the RS charter also seek to clarify that the group is only open to NERC-registered transmission or generation owners in the PJM region who are signatories to the RTO's operating agreement. Attendees are required to hold critical energy/electric infrastructure information (CEII) clearance. Invited guests are also permitted to attend.

Addition of ELCC Classes Endorsed

Stakeholders endorsed manual revisions codifying the addition of two generation categories to be modeled under PJM's effective load-carrying capability (ELCC) analysis. The concept was greenlit by the Markets and Reliability Committee at its meeting and approved by FERC (*ER25-1813*). (See *PJM Stakeholders Endorse Proposals to Rework ELCC Accreditation*.)

The language breaks oil-fired combustion turbines (CTs) out of the catchall "other unlimited resource" category, putting them in their own bucket, and establishes waste-to-energy steam generation as an independent class from "steam." The latter would also be renamed to "other steam" as part of the change. The changes will be effective for the 2027/28 delivery year.

During the June MRC meeting, PJM presented ELCC values for the 2027/28 auction that rate oil CTs at 80% and waste-to-energy generation at 83%. The PJM Board of Managers approved parameters for the RTO's Base Residual Auction derived in part from those ratings, contravening stakeholder opposition rooted in arguments that the ELCC methodology lacks transparency. (See *PJM Stakeholders Reject 2027/28 Capacity Auction Parameters*.)

PJM's Donnie Bielak | © *RTO Insider*

The rating for oil CTs fell by 5% over initial estimates PJM presented at the March MRC meeting, while the waste-to-energy class rating remained the same. Those values were based on the 2025/26 third Incremental Auction (IA).

Transmission Expansion Advisory Committee

Market Efficiency Update

PJM has received several *proposals* to address congestion under the 2024/25 market efficiency window 1, which opened on April 11 and closed June 10. The window identified congestion on the Museville-Smith Mountain 138-kV line driven by expected load growth, and renewable development affecting the West Point-Lanexa and Garrett-Garrett Tap 115-kV lines.

Six projects focus on the Museville-Smith Mountain line, with three greenfield proposals costing between $270 million and $1.6 billion and three upgrades between $1.8 million and $131.6 million. Seven projects address the West Point-Lanexa congestion, including two battery storage proposals costing between $83.9 million and $221.7 million, three upgrades between $28.1 million and $90.9 million and two substation expansions between $21.4 million and $23.4 million. One update was proposed for Garrett-Garrett Tap with a $9.9 million cost.

Supplemental Projects

FirstEnergy *presented* a $20.4 million project in the Met-Ed zone to resolve low voltage identified in a contingency where two 230/69-kV transformers at the South Reading substation are offline. The project would install a new 230/69-kV transformer, a 69-kV grounding transformer, two new 230-kV circuit breakers, a 69-kV breaker and new relaying. It has a projected in-service date of Feb. 15, 2027, and is in the conceptual phase.

The utility also *revised* the scope of a project to rebuild the 7.2-mile Penelec section of the Ashtabula-Erie West 345-kV line to address maintenance issues with insulators and H-frame structures. The project is now proposed to include replacing disconnect switches at Erie West and revise relay settings at Ashtabula, increasing the cost from $38.7 million to $52.4 million and pushing the in-service date from April 9, 2027, to March 31, 2027.

Exelon *presented* a $24.4 million project to replace a 345/138-kV transformer at its Skokie substation in deteriorating condition and with a possibly loose core/coil assembly. The first phase would install a new 138-kV, 115.2-MVAR capacitor bank, followed by removal of the tertiary 34-kV capacitor bank and replacement of the transformer and a 138-kV circuit breaker.

AEP *presented* several new service requests to serve large loads across Ohio, including a:

- 1,000-MW customer near the Hanging Rock substation in Scioto County by March 1, 2029;
- 1,200-MW load near the Muskingum substation in Waterford by Nov. 1, 2028;
- Customer near the East Lima substation in Lima seeking service for 500 MW by Dec. 31, 2028, which is expected to ramp to 900 MW;
- 300-MW load near the East Lima-Fostoria Central 345-kV line in Findlay by Sept. 30, 2028; and
- 500-MW customer south of the Maddox Creek substation in Van Wert by Dec. 31, 2028. ■

— Devin Leith-Yessian

PJM Board Initiates CIFP Addressing RA and Large Loads

Continued from page 32

stakeholders reflected growing consensus that finding solutions to the potential resource adequacy challenges posed by rapidly interconnecting large loads should be one of PJM's highest priorities," the board wrote.

Board Overrides Stakeholder Rejection of Auction Parameters, Directs Hiring of Consultant

The board also has opened a process to explore changes to how PJM calculates the installed reserve margin (IRM) and forecast pool requirement (FPR), key parameters for determining the amount of supply that will be procured in capacity auctions. The Members Committee rejected staff's recommended values for the 2027/28 BRA during its July 23 meeting, with stakeholders arguing the effective load-carrying capability (ELCC) modeling that serves as an input to the calculation lacks transparency. It also took issue with the endorsement being requested on the same day as the first read. (See *PJM Stakeholders Reject 2027/28 Capacity Auction Parameters*.)

In an Aug. 4 *letter*, the board nonetheless approved the parameters and directed staff to continue working with stakeholders in the ELCC Senior Task Force to draft changes to the model that could be implemented for the 2028/29 BRA. That work will be bolstered by a consultant the RTO will bring on to "identify additional recommended enhancements to discuss at the ELCCSTF or other similarly focused stakeholder group(s) for implementation after the 2028/29 BRA." The letter also calls for a detailed description of the ELCC model to be published.

"Although the member vote is advisory, the PJM board discussed potential options for reengaging the stakeholders on this matter; however, the PJM board reflected on stakeholder feedback, including the short timeline, and is concerned about the possibility of auction delay for the 2027/2028 BRA," the board wrote.

"Implementation of an alternative methodology to calculate the IRM and FPR would follow additional stakeholder discussion, a vote, an approved filing with the FERC, a recalculation of the IRM and FPR and a restart of the calculation of all other auction parameters currently being determined under the existing rules. This path would inevitably result in a delay of the auction, creating uncertainty in our marketplace during a period where we are in need of new supply," the board wrote.

The approved parameters increase the IRM to 20%, up from 19.1% in the auction prior, while the FPR would increase from 0.9170 to 0.9260, effectively increasing the reserve margin and amount of capacity the RTO would aim to procure in the 2027/28 auction. ■

PJM MIC Briefs

Stakeholders Discuss 2026/27 Capacity Auction Results

The Market Implementation Committee discussed the significance of PJM falling short of its reliability requirement and other details in the results of the 2026/27 Base Residual Auction, which cleared at the $329.17/MW-day cap across the RTO.

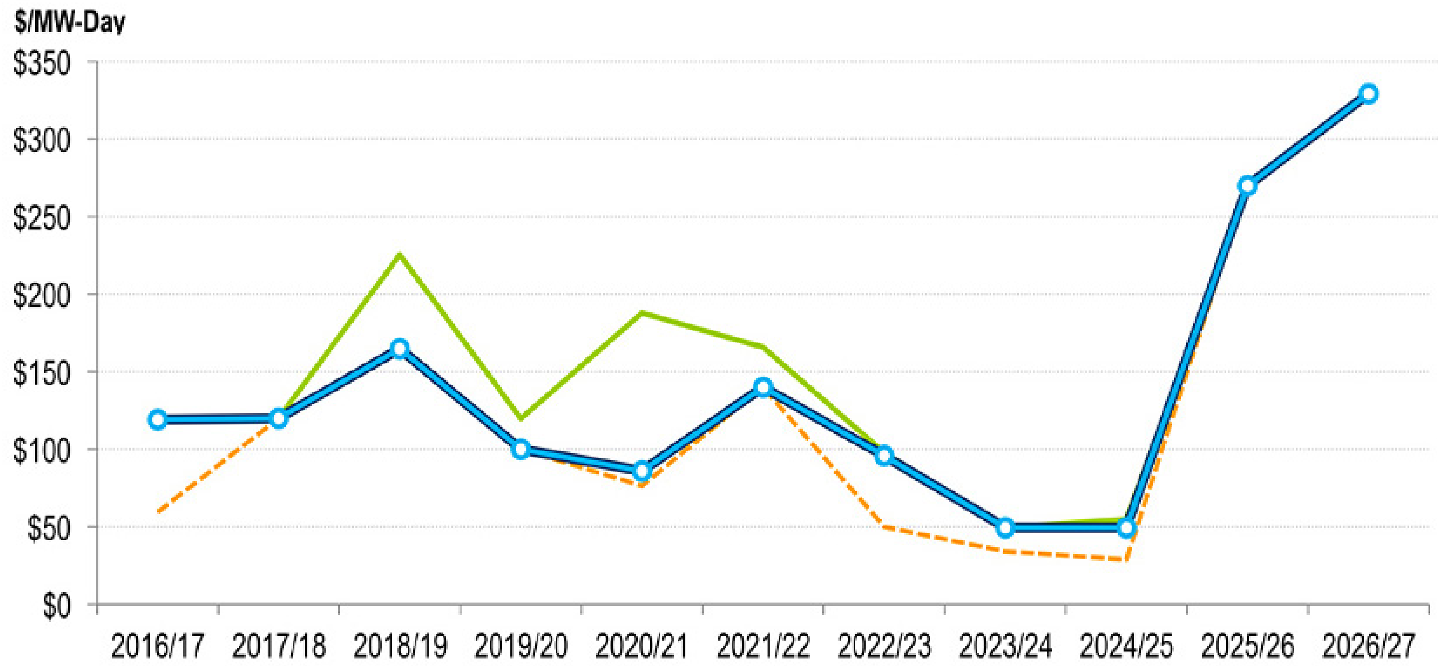
Gregory Poulos, executive director of the Consumer Advocates of the PJM States, said the RTO had buried the lede on the importance of failing to meet the reliability requirement, particularly because load is expected to surge higher in the 2027/28 auction scheduled to be conducted in December. (See *PJM Capacity Prices Hit $329/MW-day Price Cap*.)

Despite PJM's efforts to speed interconnection studies and allow more resources to advance toward construction, only 2,400 MW of additional unforced capacity was provided by renewable resources and storage in the auction. Poulos noted that outgoing FERC Chair Mark Christie spoke during a press conference July 24 about his concern that a long-discussed reliability crisis is now rearing its head in the 2026/27 BRA as slow generation growth meets data center load growth. (See *Christie Says Farewell to FERC at Final Meeting as Chair*.)

Poulos told *RTO Insider* the advocates are frustrated by the administrative levers PJM decided to pull in the design of the 2026/27 auction, but that those issues are dwarfed by the potential impact of the 30 GW of data center load growth the RTO is projecting. He said the RTO must engage in "ruthless prioritization" as it determines the best approach to meeting its resource adequacy needs, but he said he is not aware of any changes that could handle load growth of that magnitude.

Exelon Director of RTO Relations and Strategy Alex Stern said the extent of the capacity shortfall is fairly minor, with the auction procuring a reserve margin of 18.9% against a 19.1% requirement, which amounts to 309 MW of installed capacity. He questioned whether there are internal discussions ongoing at PJM related to expanding the options around how to get more generation online "so that we don't just have customer bills going up but no new plants getting built."

PJM Director of Stakeholder Affairs Dave Anders noted that staff brought an *issue charge* to the Planning Committee on Aug. 5 intended to allow new resources capable of partial operation while their network upgrades are still under construction to receive provisional interconnection service. While that wouldn't move the needle on the capacity market, he said, it could allow more energy to be available to dispatchers during critical periods.



Capacity Type	BRA	BRA Resource Clearing Prices ($/MW-day)*		
		Rest of RTO	BGE	DOM
Capacity	2026/27**	$329.17	$329.17	$329.17
Performance	2025/26	$269.92	$466.35	$444.26

A PJM graphic shows capacity prices between the 2016/17 and 2026/27 Base Residual Auctions. | *PJM*

PJM's Pete Langbein said there are several initiatives that have resulted in changes effective for the 2027/28 auction, including expanding the availability window for demand response resources and the Reliability Resource Initiative (RRI), which added 51 resources totaling 11,793 MW of nameplate capacity to the Transition Cycle 2 study cluster. (See "Expanded Demand Response Modeling Endorsed," *PJM MIC Briefs: Feb. 5, 2025* and *PJM Selects 51 Projects for Expedited Interconnection Studies*.)

"By all means, we are trying to be proactive to look at what can be done," he said.

PJM Senior Vice President of Operations Mike Bryson also said the executive leadership team has set resource adequacy as its top focus since the publishing of the RTO's "4R's" *white paper* finding that load growth, generation deactivations and slow new entry could compromise reliability. "It's a focus of the entire executive team," he said.

Langbein said the RTO cleared very close to the requirement, and almost all generation cleared in the auction, aside from some resource owners who did not understand the process to request removal of capacity status or those with external contracts who did not realize they needed to go through the must offer exemption process.

But "this is not horseshoes. 'Very close' is not same as meeting the requirement," Independent Market Monitor Joe Bowring told *RTO Insider* in an email. "To the best of my knowledge, PJM has never been short in the capacity market at the total RTO level in the history of the capacity market. This is a clear warning sign. PJM needs to directly address the impact of large data center loads which will overwhelm the grid if not addressed in the very near term. Hand waving is not the appropriate response."

Bowring said some of the resources that did not offer ran afoul of the rules because of deadlines, and the Monitor will be looking at the subject closely and release more information.

John Horstmann, senior director of RTO affairs for AES Ohio, asked if there has been any progress made on estimating the total amount of capacity that was removed from the market after the implementation of effective load-carrying capability (ELCC) and changes in accreditation, as well as the price impact on the total cost of capacity.

Bowring said the Monitor is working on calculating those values and will likely include them in its series of reports on the auction.

"The short answer is that ELCC removed a significant level of megawatts from the auction. The calculation of the exact amount requires analysis of the impact both on supply and demand of ELCC on the amount of capacity that would clear," Bowring said.

Presenting the auction results, Langbein said 2,669 MW of UCAP in new generation and uprates were offered in the auction, reversing a trend of declining new entry across the prior three auctions. About 1,100 MW of capacity interconnection rights scheduled to be deactivated were also withdrawn, keeping that output in service. He said staff are in the process of updating the auction *report* to include a note with the amount of ICAP offered in response to stakeholder requests.

PJM Presents Updated Quadrennial Review Inputs

PJM is planning to delay votes on several proposals to revise key capacity market parameters by one month to receive updated cost of new entry (CONE) values for combustion turbines and combined cycle generators as part of the ongoing Quadrennial Review process, though no impact to the auction timeline is expected.

The MIC will vote on the proposals during its Sept. 10 meeting, followed by votes at the Markets and Reliability Committee and Members Committee on Sept. 25, with the aim of a filing being submitted to FERC in October.

The delay will allow the Brattle Group, retained to assist in the review, to update the CONE values with physical updates — including wet compression, updated technical specifications from General Electric including higher firing temperature, and an adjusted inlet pressure assumption — and financial updates, including the impact of 100% bonus depreciation returning because of the One Big Beautiful Bill Act. Brattle and Sargent & Lundy presented additional information from GE to stakeholders on its standard payment schedule for gas turbines and showed that it was in reasonable agreement with the capital drawdown schedules used for the CC and CT in Brattle's analysis.

PJM's Skyler Marzewski *said* that if Brattle were to exactly follow the GE turbine payment schedule, it would have little impact and result in the CONE for a CT increasing by less than $7/MW-day and less than $2/MW-day for a CC unit if incorporated into PJM's proposed variable resource requirement (VRR) curve. He said one reason this impact is relatively small is because turbine payments are just one portion of capital drawdown, with owner-furnished equipment accounting for about 39% of overnight capital costs for a CT and 28% for a CC.

Bowring said GE's perspective on the total payments by purchasers, including but not limited to payments to GE, should be treated as informative on its payment schedule, not dispositive on the overall drawdown costs for a new generator.

"The Market Monitor has built the drawdown schedule from the bottom up, while Sargent and Lundy/Brattle did a top-down analysis based on their general view about industry practice related to all payments associated with buying and installing a turbine," Bowring wrote in an email. "GE's general opinion about payments to others involved in the process is anecdotal and not the appropriate standard."

Brattle Principal Sam Newell and PJM Chief Economist Walter Graf said they met with GE, joined by Sargent & Lundy, to receive more information about the cost and payment schedule for turbines and confirmed that the capital drawdown schedule in Brattle's analysis is reasonably aligned with GE's payment schedule for turbines. They said the payment schedule for turbines has become increasingly front-loaded, which increases installed costs. Graf said the Monitor was also invited to this meeting but refused, and the delayed spend schedule proposed by the Monitor in its proposal results in a drastically different turbine payment schedule from what GE said would be reasonable.

Bowring said the Monitor has discussed GE's own payment requirements for the purchase of a turbine directly with GE and has incorporated GE's required payment schedule in its drawdown schedule. He also disputed Graf's characterization of the Monitor's involvement.

"The fact that the actual payment schedule required by GE differs from the assumptions made by Brattle is a reason to question the Brattle top-down derivation. It is not a question of what Brattle assumes is common practice. It is a question of what GE requires," he said.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said Brattle and the Monitor should present additional details on its discussions with GE and data received from the company to inform their drawdown schedules, along with more documentation from GE and engineering, procurement and construction (EPC) companies.

"Sunshine is going to be the best disinfectant on this discussion," he said.

Presenting an update on the impact the changes could have on the VRR curve, Newell said the 100% bonus depreciation included in the One Big Beautiful Bill Act amounts to a tax break that "pretty significantly lowers the cost to the owner" of a new resource.

1st Read on Offer Capping of Advance Scheduled Resources

PJM's Phil D'Antonio presented a first read on a proposal to cap resources committed ahead of the day-ahead market at their cost-based offer. The proposal is set to be voted on by the MIC at its September meeting, and additional manual, operating agreement and tariff language would need to be drafted and voted on subsequently. (See "Offer Capping Resources with Advance Commitments," *PJM MIC Briefs: March 5, 2025*.)

Advance commitments have been used more widely since the institution of the conservative operations procedure, which allows PJM to schedule resources expected to be necessary to maintain transmission security during strained operating conditions, especially winter storms. The cost of that practice has been criticized by consumer advocates, and the use of out-of-market commitments has been opposed by some generation owners. (See *PJM: 'Conservative Operations' Maintained Reliability During Jan. 2024 Storm*.)

Sotkiewicz said PJM's governing documents only allow for offer capping resources with advance commitments to address transmission constraints, arguing that offer capping resources committed for other purposes violates the tariff and negatively impacts price formation.

"I think this is going down a very dangerous path," he said.

PJM's proposal states that the "PJM tariff and [Operating Agreement] allow for offer capping only for transmission constraints. Current [Manuals 11 and 13] language allows offer capping for units scheduled in advance of the day-ahead market but does not have supporting tariff and OA language."

Offer Capping Issue Charge Revised

The committee endorsed by acclamation an expansion of the offer capping *issue charge* brought by the Monitor to include additional consideration of the treatment of resources with advance commitments in the day-ahead market, how uplift is calculated for resources committed for multiple days and additional transparency into how resources are scheduled.

The issue charge was renamed to reflect the wider scope, removing references to offer capping to instead read as "resource scheduling prior to the day-ahead energy market." (See "Monitor Proposes Rewrite of Offer Capping Issue Charge," *PJM MIC Briefs: July 9, 2025*.)

The revisions also add additional education on the triggers for allowing advance commitments, notifications that go out to stakeholders that such action has been taken, commitment instructions to resources, the inputs and models that determine commitment parameters and operational constraints not included in unit parameters, such as fuel inventory, gas nomination cycles and any run hour limitations associated with environmental permits.

Renewable Dispatch Proposal Endorsed

Stakeholders endorsed a PJM proposal to create a new Effective EcoMax parameter for wind and solar resources intended to better capture how they are capable of operating in real-time energy market dispatching. The proposal passed with 98.9% support. (See "First Read on Real-time Renewable Dispatch," *PJM MIC Briefs: July 9, 2025*.)

The forecast for wind and solar output would be updated ahead of each five-minute interval, which would then feed into the Effective EcoMax parameter and update maximum output the generator can be dispatched up to. The existing EcoMax parameter limits security-constrained economic dispatch (SCED) based on the parameters submitted by resource owners, which can become stale and lead to units being curtailed below their potential.

The proposal was modified by PJM to retain curtailment flags for wind resources and establish them for solar as well; they had been set to be removed for all resources in July, but a Distributed Resources Subcommittee poll showed 96% support for allowing them for renewables.

Renewables would be limited to ramping at 20% of their ICAP per minute to minimize the volatility that can come from sudden shifts in renewable output. PJM's Vijay Shah noted that would still allow those resources to go from 0 to 100% of their capability in a single interval.

Regulation Market Redesign Endorsed

The committee endorsed by acclamation a slate of manual revisions to conform with PJM's regulation market redesign, which was approved by FERC in June 2024 (*ER24-1772*). (See "PJM Presents Manual Revisions for Regulation Market Redesign," *PJM MIC Briefs: July 9, 2025*.)

The reworking of the market creates a single price signal with resources able to offer regulation up and down products, replacing a market model where participants offered bidirectional products to provide either Regulation A for long deployments or Regulation D for fast response. (See "PJM Presents Regulation Market Rework," *PJM MRC/MC Briefs: Dec. 20, 2023*.)

The proposal includes revisions to Manual 11: Energy & Ancillary Services Market Operations, which *detail* offer structure, DR participation and lost opportunity cost credits; Manual 15: Cost Development Guidelines, *including* a stipulation that regulation resources also participating in the energy market do not receive variable operations and maintenance cost increases; and Manual 28: Operating Agreement Accounting, which *outline* the regulation clearing price credit formula. ■

— Devin Leith-Yessian

PJM OC Briefs

July Heat Wave Update

PJM's Kevin Hatch *presented* an update on how two heat waves between July 14-17 and 23-30 affected PJM operations, which involved multiple demand response (DR) deployments and emergency alerts and advisories.

Loads reached their apex on the afternoon of July 29, with a preliminary integrated hourly peak of 157,487 MW, which Hatch said would be the ninth highest the RTO has seen. He said the day saw atypically high load ramping, renewable performance below the seasonal effective load-carrying capability (ELCC) value, and generation outages exceeding the three-year average. Around 3.7 GW of DR was deployed.

The declaration of maximum generation and load management alerts without extreme temperatures raised concerns for PJM that load growth and renewable penetration could jeopardize resource adequacy. During the Aug. 5 Planning Committee meeting, PJM said it had initiated 11 maximum generation and load management alerts in 2025, more than the prior decade combined.

The first heat wave saw maximum generation and load management alerts July 15 and 16, which Hatch said included notifications to neighboring balancing authorities that off-system sales could be curtailed.

A generation maintenance outage recall was issued ahead of the second heat wave, followed by hot weather alerts starting in PJM West on July 22 and for the whole RTO the following day. Maximum generation and load management alerts were issued for July 24, 25, 28, 29 and 30. Pre-emergency load management was called July 28 for the BGE, PEPCO and Dominion zones, expanded to the full RTO the next day, when all available long- and short-lead DR was called.

PJM's Kevin Hatch presents information on the RTO's performance during a pair of heat waves in July. | *© RTO Insider*

Synchronized Reserve Performance Inquiry

The Independent Market Monitor *presented* the results of a poll of resource owners who saw their units underperform during the July 1 synchronized reserve performance inquiry, which saw 79.5% response for individual resources. The event lasted 10 minutes and 38 seconds, with 2,398 MW of generation and 544 MW of DR assigned.

Joel Romero Luna, of Monitoring Analytics, said the owners of 33 underperforming resources were contacted and responses covered 20 units. The single-largest identifiable cause of those units' shortfall was inaccurate parameters having been submitted, accounting for around 50 MW of the 581-MW shortfall. Around 225 MW of shortfall was categorized into an "other" category due to the number of resource owners falling below the confidentiality requirement of at least four generation owners providing the same information, allowing anonymized aggregation.

He said outreach to generation owners is continuing with the goal of increasing the response rate.

July Operating Metrics

PJM saw an average hourly forecast error of 1.7% for July and an average peak error of 1.78%, according to the RTO's monthly operating *metrics*. The 3% daily peak error benchmark was exceeded three days, with over-forecasting on July 19, 24 and 26 attributed to storms causing load to come in lower than expected.

The month saw four spin events, two shared reserve events, seven maximum generation and load management alerts, five pre-emergency load management reduction actions, seven shortage cases, 10 hot weather alerts and 39 post-contingency local load relief warnings. All the shortage cases occurred July 28, with one primarily due to generation loss and six due to solar generation falling faster than load was expected to decline between 6:59 p.m. and 7:25 p.m.

Two of the spin events exceeded 10 minutes, allowing the RTO to begin measuring a rolling average to track synchronized reserve performance for the purpose of potentially backing down a 30% adder to the reserve requirement. PJM established the adder in May 2023 to address poor reserve performance, which PJM aimed to address through changes to reserve deployment implemented in December 2024.

In March 2025, PJM began measuring reserve performance, backdated to December 2024, and created a paradigm under which the adder could be reduced if reserve performance is above 75% across a rolling average of three events exceeding 10 minutes.

Under that model, the adder would be reduced by 10% if performance across the rolling average is between 75 and 85%. It would be reduced by 20% if the average is between 85 and 95%, and it would be eliminated at performance above 95%. The adder could be increased by 10% if performance falls below 75%, but the reserve requirement must remain within a 100-to-130% band. (See *PJM OC Briefs: March 6, 2025*.)

The July 1 and 22 events, paired with a spin event Feb. 5, carry an average of 74.4% performance, meaning the adder remains untouched. For the next event to reduce the adder by 10%, performance would need to be 66.7% or greater; performance at 96.7% or greater would result in the adder being reduced by 20%.

The July 22 event lasted 10 minutes and 32 seconds and saw 2,764 MW of generation and 548 MW of DR assigned, with performance at 79 and 80% respectively. A July 30 event last 5 minutes and 57 seconds, with 3,588 MW of generation and 328 MW of DR assigned, with performance at 59 and 72% respectively; the next day another spin event was declared lasting 6 minutes and 16 seconds, with 2,802 MW of generation and 582 MW of DR assigned, with 45 and 63% performance.

Generation Deactivation Manual Revisions

The Operating Committee endorsed by acclamation *revisions* to Manual 14D: Generator Operational Requirements to rework the requirements for a resource requesting deactivation. The proposal will advance to the Markets and Reliability Committee for a first read at its Aug. 20 meeting, followed by endorsement on Sept. 25. (See "1st Read on Manual Revisions Detailing Generation Deactivation Process," *PJM OC Briefs: July 10, 2025*.)

Resource owners would be required to provide PJM with at least one year's notice before going offline and follow the must-offer exemption process if they are seeking to not participate in the capacity market. The proposal also expands transparency requirements, mandating that resource owners entering into a reliability-must-run agreement with PJM provide the RTO and the Monitor with an estimate of the costs that would be recovered under the agreement, which would be publicly posted. Ongoing monthly updates would also be required during the term of the RMR agreement. Also, the Monitor would publicize market power letters.

The language would remove a $2 million cap on project investments allowable under the deactivation avoidable cost credit (DACC) compensation methodology, limit the adder for investments to 10% and remove language causing the credit to be determined through the daily deficiency rate rather than the deactivation avoidable cost rate (DACR) when the DACR and applicable multiplier exceed the deficiency rate. ■

— Devin Leith-Yessian

SPP Regional State Committee Briefs

Regulators Endorse Policy to Resolve M2M Congestion

KANSAS CITY — SPP state regulators have approved a policy that establishes criteria for developing joint transmission projects with other RTOs to cost-effectively address persistent market-to-market (M2M) congestion.

SPP intends to use the targeted market efficiency projects (TMEPs) to resolve M2M congestion that has resulted in millions of dollars of charges on its seam with MISO. SPP's neighbor already uses TMEPs on its PJM seam.

The cost of each project would be allocated between SPP and MISO based on the ratio of historical congestion costs, adjusted for M2M settlement effects. The interregional cost allocation would be recovered through the regionwide annual transmission review requirements.

Louisiana and Texas voted against the policy over cost-allocation concerns during the SPP Regional State Committee's Aug. 4 meeting. Attorney Dana Shelton, proxy for Louisiana Public Service Commissioner Mike Francis, expressed concern about "the allocation on a regionwide basis in the absence of showing a regionwide benefit."

Minnesota Public Utilities Commissioner John Tuma questioned the reluctance to talk about market efficiencies, saying TMEPs will benefit only SPP's ratepayers.

"This concept is about creating market-to-market benefits for our ratepayers. I think exploring it is only in our best interest at this stage," he said. "Minnesota has joined this organization because we are one of those seams organizations, and we do see the benefit of these [M2M] efforts. Is this a big one? No … but it's the kind of thing that will help us out in the long run."

The TMEPs would apply only to M2M flowgates along the MISO seam with a minimum of at least $1 million in historical congestion costs. Staff are proposing a $20 million project cap with an in-service time frame of three years and a four-year payback of avoided congestion costs.

SPP's Clint Savoy told the RSC that RTO staff is trying to filter the list of constraints they want to fix as part of the biennial joint system study with MISO. He said staff will use historical market data to find operating days when constraints bound in the day-ahead market. They will calculate the production cost for the entire market, remove the constraint and rerun the production cost analysis.

Minnesota Commissioner John Tuma makes a point during RSC's August discussion. | *© RTO Insider*

"The change in production cost is essentially the benefit that SPP receives, so it's a reduction in the production cost for the market as a whole," Savoy said.

The committee agreed with staff's recommendation to stop moving a tariff change (*RR681*) that allocates costs of seams projects outside the FERC Order 1000 interregional process. Instead, it remanded the issue back to the Cost Allocation Working Group to address stakeholder concerns and asked it to provide an update during the RSC's November meeting.

The Markets and Operations Policy Committee rejected the proposal during its July meeting with only 54.9% approval. Members were uncomfortable about whether the projects would be subject to the grid operator's competitive process screening. (See "Seams Cost Allocation Rejected," *SPP MOPC Briefs: July 15-16, 2025*.)

The RSC also granted CAWG's request to delay the annual stakeholder review of the Safe Harbor Limit, which sets designated resources' eligibility for base-plan funding at costs less than or equal to $180,000/MW. The working group said the delay was necessary because of "significant changes in SPP processes."

Bylaw Change for Western RTO

The RSC approved an amendment to its bylaws that will allow Western commissioners to join the committee upon the *RTO's expansion into the West* in 2026. The expansion will make the Arizona, Colorado and Utah commissions eligible to add representatives to the committee.

Commissioners will be able to vote on proposed policy or tariff changes and other matters only if the proposal applies to the interconnection where their state is located. As Nebraska, New Mexico and South Dakota straddle both interconnections, those states will be limited to one vote if the proposal applies to both regions.

The Western commissioners will be eligible to join the RSC after April 1, 2026, when the RTO expansion goes live. Staff said vendors are successfully building and testing market systems, with member testing to begin in September.

Three Western commissioners sat in on the meetings: Arizona's Kevin Thompson, New Mexico's Greg Nibert and Wyoming's Mike Robinson. Missouri's Glen Kolkmeyer also was a guest although his chair, Kayla Hahn, represents the state on the RSC.

The committee also endorsed a three-person Nominating Committee consisting of RSC President Patrick O'Connell, South Dakota's Kristie Fiegen and Tuma that will recommend the 2026 leadership during the November meeting. It also approved a 2026 budget that passes $1 million for the first time ($1.18 million) by including an extra $500,000 for consulting services and making allowances for increased membership.

Employee No. 3 Speaks out

Bruce Rew, who recently announced his pending retirement from SPP as senior vice president of operations, was greeted with a round of applause before one of his last updates during the Joint Stakeholder Briefing following the RSC meeting. (See *SPP's Rew to Retire After 35 Years in Operations*.)

"Bruce reminds us he was Employee No. 3. I'm not sure 1 and 2 are still alive, but Bruce has had a remarkable career at SPP," board Vice Chair Ray Hepper said, teasing the 35-year veteran. "So this may be among your last opportunities to really chew on Bruce in a board meeting."

SPP's Bruce Rew reacts to director Ray Hepper's comments during his presentation. | © *RTO Insider*

Rew said SPP has issued only one resource advisory thus far in 2025, which lasted two days in April, compared with five in 2024. During that period, demand peaked for the year at 56.6 GW, about 1,500 MW below the all-time high. Despite the demand but with negative LMPs, staff were able to export almost 5 GW of energy to MISO and PJM June 25-26 when the RTOs' solar power vanished during the evening hours.

"As we gain more and more solar, that's something that we're going to continue to manage operationally to make sure that we're prepared for that as well," Rew said. "We potentially could have that same experience if we get 5 or 10,000 MW of solar."

It will be a while yet. The grid operator recently added its first gigawatt of solar capacity, complementing its 35.6 GW of wind capacity. It has added more than 3 GW of capacity in the past year, pushing its registered capacity past 100 GW.

SPP has *published a report* on the April 26 load shed event near Shreveport, La., one of three in the footprint in 2025. The report analyzes the event, identifies the main causes, examines SPP's response and provides recommendations and improvements to prevent similar incidents in the future. (See *SPP Addresses 3rd Load Shed Since March 31*.)

SPP Lays out Market Principles

Carrie Simpson, SPP vice president of markets, followed Rew to the podium and discussed the priorities for market design changes set in a staff white paper that is circulating: price discovery and transparency, economic efficiency, reliability effectiveness and system performance.

Referencing the 5 GW of exports to MISO and SPP, Simpson called it the result of a "healthy seam."

"It's a good indication … that our pricing was supporting the rest of the interconnection, because people were able to buy from us and sell into MISO and PJM," she said. "Had these exports not occurred, our LMPs would have been significantly even lower because we would have had to back down even more generation. And so just a good indication of the market working well and the signals being available to participants to take action and move power where it was needed or more efficiently needed in the interconnection." ■

— Tom Kleckner

Tri-State Plan Includes Renewables, Batteries and Gas

Environmental Groups Critical of Emissions Implications

By Elaine Goodman

Colorado regulators have approved Tri-State Generation and Transmission Association's plan to add 1,657 MW of new resources from 2026 to 2031, despite objections about the inclusion of a new natural gas plant.

The Colorado Public Utilities Commission voted 3-0 on Aug. 1 to approve the plan.

New resources in the plan include 400 MW of wind, 300 MW of solar and 650 MW of battery storage, along with 307 MW from a new natural gas plant in Moffat County in northwestern Colorado. The battery resources will be Tri-State's first experience with battery storage systems.

In addition, Tri-State plans to replace turbines at the J.M. Shafer gas-fired plant to boost capacity.

The 1,657 MW of resources were included in Tri-State's preferred portfolio, one of six analyzed in the implementation report for its 2023 electric resource plan (ERP). The report follows commission approval for Phase 1 of the ERP and a competitive bid process.

Another plan, referred to as Portfolio 6, excludes the new gas plant but increases battery storage to 1,175 MW, for a portfolio total of 1,900 MW. That plan also includes new turbines at Shafer.

Tri-State chose its preferred portfolio "as a result of the portfolio's overall performance across the reliability, environmental and financial categories," the Colorado-based power cooperative said in its implementation report.

The preferred portfolio was the least-cost option based on the present value of revenue requirements (PVRR), not including the social cost of emissions. The PVRR of the preferred portfolio would be about $88 million less than that of Portfolio 6.

Like all the portfolios analyzed in the implementation report, the preferred portfolio meets reliability targets. It achieves an 80% reduction in greenhouse gas emissions in Colorado in 2030 relative to 2005 levels.

"However, the other portfolios analyzed result in significant, unnecessary financial burdens by aggressively pursuing resources with high transmission interconnection upgrade costs" not needed to achieve the same benefits, Tri-State said.

The new resources are needed in part due to the retirements of the Craig and Springerville coal-fired power plants, slated for 2028 and 2031, respectively.

"Retirement of dispatchable coal resources cannot be affordably or reliably replaced solely with semi-dispatchable resources," Tri-State said.

Commission Chair Eric Blank said he understood the resource diversity benefit of natural gas.

"For me, given our lack of rate regulation over Tri-State, I don't think we should be substituting our judgment for that of the utility when there's a tough choice to be made between competing portfolios where either could be deemed reasonable," Blank said.

Tri-State Generation and Transmission Association's plan to add new resources is intended to make up for the upcoming retirement of two coal-fired plants: Springerville and Craig, seen here. | *Shutterstock*

Why This Matters

The approved resource portfolio represents Tri-State's first foray into battery storage, as the cooperative prepares for the retirement of two coal-fired plants.

Commissioners also agreed with Tri-State that "time is of the essence" for procuring new resources due to a "volatile" market for renewable energy equipment and recent federal tax and trade actions.

Non-gas Portfolio

Other parties had urged Tri-State to choose Portfolio 6, which excludes the new gas-fueled power plant.

The Natural Resources Defense Council and the Sierra Club, filing together as "the conservation coalition," said the present value of revenue requirements for Portfolio 6 was similar to that of the preferred portfolio when considered over the 19-year analysis period. Portfolio 6 had the lowest PVRR when the social cost of emissions was included, they said.

Portfolio 6 would result in lower GHG emissions for Tri-State "for little to no incremental cost," the coalition said in a filing. The groups noted that Tri-State must eliminate its Colorado GHG emissions by 2050.

The groups also questioned the excess capacity resulting from the new gas plant and the "explicit assumption that Tri-State will overbuild capacity in order to sell into the market."

"The commission's rules, and prudent utility planning, simply do not countenance a regulated utility operating like a merchant generator in the way Tri-State proposes," the coalition said. ■

SPP Celebrates Novel Consolidated Planning Process

Board Approval Ends 3 1/2-year Effort to Blend GI, Planning

By Tom Kleckner

KANSAS CITY — SPP's Board of Directors has approved a tariff change establishing an integrated, three-year transmission planning cycle that represents a "watershed" moment and a "first-in-the-country" mechanism, RTO officials said.

The board endorsed the proposal during its quarterly meeting Aug. 5 following a unanimous advisory vote by the Members Committee. The vote added to previous unanimous endorsements from state regulators, the Markets and Operations Policy Committee and five other stakeholder groups.

The Consolidated Planning Process (CPP) replaces SPP's current sequential planning and generator interconnection studies that have resulted in clogged queues and an average of six-year wait times before resources go into service. (See *SPP 'Blazes Trail' with Consolidated Planning Process*.)

The new process comprises a long-term 20-year study and an annual 10-year assessment, aligning system modeling, planning assumptions and cost allocation across load and generation needs. The CPP-10 includes a GI capability study, a GI decision point and a regional transmission assessment that recommends projects for construction. The CPP-20 establishes a 20-year regional vision.

The CPP also establishes a general contribution funding mechanism, called GRID-C, for upgrades that serve both load and generation, enabling shared cost responsibilities and fewer restudies.

SPP says the streamlined framework improves cost certainty for stakeholders and promotes equitable cost sharing. Casey Cathey, the grid operator's vice president of engineering, said the CPP will lead to faster integration of genera-

Why This Matters

SPP's Consolidated Planning Process, which will produce its first assessment in 2028, is an integrated, three-year transmission planning cycle blended with generator interconnection studies. Staff and stakeholders say the CPP is an innovative process that could set the tone for the industry.

SPP's Casey Cathey (right) thanks everyone involved in developing the Consolidated Planning Process. | © RTO Insider tion and remove "huge challenges" from the current three-phase study process.

"If you show up and you pay your GRID-C, you're committed," Cathey said. "Within seven months on an annual basis, we'll get to a [generator interconnection agreement], and you may move forward with your build. This is a critical area for modernizing the grid. This is quite innovative across the nation, if not the entire world. We're blending generator interconnection processes and transmission planning processes in a very elegant solution for providing cost certainty."

Cathey may not be wrong about the "elegant solution."

"This will be the only RTO that can really offer upfront cost certainty to interconnection customers, which is so incredible for those in the development of assets," Pine Gate Renewables' Brett White said.

The cost-sharing framework assigns GI costs based on transmission usage, projected accreditation needs, the CPP-20 portfolio and future generation.

The CPP effort grew out of the Strategic and Creative Re-engineering of Integrated Planning Team (SCRIPT) formed in the last decade to improve SPP's transmission planning. That led to a task force that continued the work, meeting more than 200 times over three and half years to put together the process.

Independent Director Steve Wright recalled that the project was already underway when he joined the board in 2023.

"It is a really big national problem that people new to the industry look at what's going on here and how long it takes us to figure out interconnections," he said. "This process is byzantine and not meeting the moment, because we need electricity. ... [The board] was seeing all things going on across the country and saying, 'What's going on here is truly creative and can be a national model.' And here we are at this moment, when it's actually happened ... it's going to create a model that people can either use or measure against in terms of what are they doing to be able to make this work."

Vice Chair Ray Hepper, a Maine resident, said the CPP was a "first-in-the-country" innovation, one that has attracted notice in various corners of the country.

"I know a lot of people in New England, and they'll call me and ask, 'What's going on?'" he said. "Everybody else is watching. This is a really remarkable feat."

EDP Renewables' David Mindham, apologizing for his "fluffy comments," added his kudos for CPP. He said it is unlike anything EDP has found in the other RTOs it participates in.

"It's very seldom that a process truly comes together, where every interested party sits in a room for years at a time and works through everybody's issues and ... comes to consensus on something. That just doesn't happen," Mindham said. "This is probably the first example of a process that I can really think of that was consensus-driven that really balanced stakeholder interests. I think we got an amazing product. I think there could be challenges in implementation. ... But if we keep up the same sort of collaboration and atmosphere with that creating this, I think we'll move through those equally as well."

David Mindham, EDP Renewables | © *RTO Insider*

SPP plans to file the tariff change with FERC by October and will request an effective date of March 1, 2026. Full implementation will begin in 2027, with the first CPP portfolios studied being delivered in 2028. Transitional work will bridge the gap between the CPP framework and the current study process for the 2026 and 2027 assessments.

"We still have a lot of work to do," Cathey said. "We have to clean up the backlog. We have to get through and complete the next [study cluster]. We have a lot of individual processes and tools."

At the same time, SPP staff are staging internal software to be ready to implement CPP and as part of a recently announced partnership with digital provider Hitachi. The companies have agreed to develop an AI-based solution that the grid operator says will reduce processing times in the GI study process by at least 80%. (See *SPP, Hitachi Partner to Use AI in Clearing GI Queue*.) ■

FERC Approves SPP Change to IC Interim Service

FERC has approved an SPP tariff change that allows interconnection customers without a pending request to ask for interim service when the study cluster's window is closed (*ER25-2476*).

In its Aug. 7 letter order, the commission found that SPP's proposal would meet the agency's independent entity variation standard, used to evaluate deviations from the *pro forma* large generator interconnection procedures and agreements established under FERC *Order 845*. The standard is designed to allow IC customers to obtain interim service sooner than otherwise would be possible.

FERC said the proposed tariff revisions "will provide additional flexibility" for interconnection customers by allowing them to submit requests that would enable a timelier IC service.

"Absent SPP's proposed tariff revisions, interconnection customers without a pending interconnection request would not be able to request interim interconnection service until the next [study] cluster window, which could occur as late as April 1, 2026, potentially delaying the connection of needed generation," the commission said.

The tariff revision also maintains existing financial and study requirements for an interim IC, FERC said. It noted the proposal includes limits such as requiring customers to submit a request in the next open study cluster window or have their interim GIA terminated, ensuring that a customer can't have interim service indefinitely.

SPP submitted its proposal in June, saying that revisions to its definitive integration system impact study (DISIS) process will allow customers to ask for interim IC service on the condition it submits requests to the DISIS queue during the next open cluster window. Customers with pending requests also will be required to maintain that request for its interim service to remain valid.

The order was effective Aug. 10. ■

— Tom Kleckner

FERC has approved SPP tariff changes for interim interconnection service. | *ITC Holdings*

SPP Board Sets Aside 765-kV Costs, Large Load Policy

By Tom Kleckner

SPP's Board of Directors has agreed to defer action on a 765-kV transmission project with a ballooning cost estimate and on staff's large load integration policy, both the source of much stakeholder discussion.

The 765-kV project, the first in SPP history, was awarded to Southwestern Public Service in February with an estimated cost of $1.69 billion. SPS filed a revised cost estimate of $3.62 billion in June, more than double the earlier projection and easily outside the variance bandwidth of +/30% that can lead to a re-evaluation.

However, SPP said the 765-kV project remains "the most cost-effective and strategically sound option" to address Eastern New Mexico's "critical needs." The grid operator has seen a 32% increase in summer peak load for the 2023 and 2024 transmission planning assessments, driven by rapid electrification of the oil and gas industry. It said "significant" growth is continuing into the 2025 and 2026 assessments.

The board deferred a decision on the project during its Aug. 5 quarterly meeting until it meets again in November, at the latest.

The directors also delayed action on SPP's proposed large load integration policy, agreeing to wait until after a special Markets and Operations Policy Committee call Aug. 21. That will allow for additional stakeholder input and technical review. The board plans to hold a joint meeting with state regulators less than two weeks after the MOPC call to discuss the issue further. Both bodies will vote on the proposal during their October and November quarterly meetings.

What's Next

Delaying action on the 765-kV transmission project and SPP's large load integration policy will give the grid operator time to reach broader stakeholder consensus. Both issues could be up for consideration again during the October and November meetings.

SPS' Jarred Cooley (right) explains why the company's estimate for a 765-kV project has more than doubled. | © *RTO Insider*

MOPC rejected the proposal during its July meeting, giving it only 53.7% approval. (See "Members Shoot down Staff's Proposal for Integrating High-impact Large Loads," *SPP MOPC Briefs: July 15-16, 2025*.)

SPP says high-impact large loads (HILLs), generally defined as anything equal to or larger than 50 MW, are investments requiring short-term costs to integrate and operate that are balanced with long-term benefits (jobs and revenue). The proposal would complete system impact studies within 90 days for the load and its supporting generation together, leading into the normal firm-service interconnection queue. Study costs would be directly assigned to the cost-causers (the requesting transmission customer), staff said.

SPS 765-kV Project Deferred

The RTO gave the Potter County-Crossroads-Phantom project a notification to construct with conditions (NTC-C); SPS could not order materials or begin construction until it provided a refined project estimate within the study's variance bandwidth.

The company's engineers revised the line costs from about $4.2 million/mile to $5.9 million/mile, comparable to what MISO and ERCOT are projecting in their 765-kV projects. They also increased SPP's original estimate of 244 miles for the project's two legs to 354 miles to account for their actual paths. The modifications accounted for more than $661 million of the increased cost estimate.

Reactor costs also increased $180 million between the two estimates, SPS said. It will incur additional expenses for two new 765/345-kV substations, necessitating three additional 20-mile 345-kV line segments, because of "land challenges."

SPS' Jarred Cooley, the utility's director of strategic planning, told the board and stakeholders that the 765-kV lines' right of way of up to 250 feet forced it to "skirt around" communities, oil and gas infrastructure, irrigation systems, archeological sites and environmental species habitats, such as the *endangered lesser prairie-chicken*.

"This is something that we, as an entire company, are digging into deeply across multiple fronts," Cooley said during SPP's joint stakeholder briefing Aug. 4. "We've spent a lot of time on this. We definitely understand the sticker shock of the comparison between the initial SPP estimates and what SPS is providing today."

American Electric Power's Stacey Burbure, vice president of FERC and RTO policy and strategy, said SPS' cost estimates are in line "across the board" with what her company is seeing. AEP has been awarded *one of three 765-kV* projects in ERCOT and owns 2,110 miles of 765-kV transmission, more than any other transmission company in North America.

"When I think about why we are here, it's because the initial cost estimate is wrong," she said.

"There's a need for improvement," Oklahoma Municipal Power Authority's Dave Osburn said, "but when I looked at what the future projections and the load increases that are being projected, I'm not sure how we can really efficiently do that without 765.

"Yes, they are more expensive than others, but there's a lot of other benefits that come with the 765 overlay," he added. "As we go through this particular project, let's learn from this, and let's figure out the true cost of building out the 765, because I do think it's something we're going to have to be addressing going forward."

As a short-term reliability project, Potter

County-Crossroads-Phantom is not eligible for the competitive process. It currently has an in-service date of 2031.

"Back in February when we addressed short-term reliability projects, I raised concerns about this particular project because it was so large. Now that the costs are more than double, my concerns are intensified, but I'm very sensitive to the fact that this is a reliability project," Director Irene Dimitry said. Alluding to the in-service date, she added, "The solution that has been identified for this near-term need is not a near-term solution."

Dimitry said she wanted to see more time taken to find the right balance between reliability and affordability by considering competitively bidding the project. She offered a motion that would rescind the board's prior approval of the project and direct staff to facilitate an expedited competitive selection process. Dimitry, who has been tasked with assembling a task force to refine SPP's competitive selection process, suggested a recommendation be made to the board at its May 2026 meeting.

The motion failed both the Members Committee's advisory vote (7-8, with seven abstentions) and the board's vote. SPP does not disclose the board's vote beyond "pass" or "fail."

SPS President Adrian Rodriguez defended the project's reliability status, saying that had it been in place in March, the utility would not have had to drop 122 MW of load for almost three hours. He welcomed the board's attention, saying, "We need to get this right." (See *SPP Addresses 3rd Load Shed Since March 31*.)

"The scrutiny is justified, and we're committed to being part of our early engagement in assessing costs with the SPP staff and bringing this before the board," he told directors. "It's clear that the costs, I acknowledge, are different from the original estimate, but that comes with validation of uses. We're excited about setting a strong precedent."

Rodriguez promised SPS would continue to update the board and work with staff before November. He said the company has focused on keeping costs as low as possible, from competitively procuring engineering and construction services to holding slots for equipment in an uncertain supply chain.

Any further delays would only increase the project's costs, Rodriguez said.

"The tradeoff that we're always sensitive to is, in this case, delayed dollars. Every day that passes, these costs can increase," he said. "I am very sensitive to moving quickly … but very concerned about any type of lengthy delay that could result in increased costs" for major transmission and distribution supplies.

"What I don't want to do is to have a self-fulfilling prophecy that we come a couple of months later [and] there are some cost increases because of the additional delays, and then we are back in the same boat," Rodriguez added. "At the end of the day, ultimately, it's our customers that are impacted."

Large Load Policy on Hold

MOPC's discussion of SPP's *high-impact large load integration policy* stretched over two days in July.

Members had agreed there is a need to address how large loads are added to the system but raised concerns about maintaining reliability, cost-allocation equity and transparency. Views differed on how to balance speed with planning thoroughness; how to define qualifying load types; and whether existing processes could be adapted or new pathways were needed.

The discussions have continued since then. COO Antoine Lucas surveyed the audience for the board meeting and said he could see stakeholders he has had phone conversations with in recent weeks as he worked to "try to get people comfortable as quickly as we could," he said.

He argued that the policy will help SPP integrate the large loads and their high impact.

"The high-impact portion of it is really based on our assessment that these loads have the ability to materially impact the reliable operations of the system," he said. "For that reason, we felt that there was a need for pretty detailed and enhanced policy proposals to ensure that we were able to identify what those differences were and some of the risks that those posed."

Lucas said staff will continue to engage with stakeholders until an MOPC call Aug. 21. The joint board and Regional State Committee meeting that follows will give staff additional input in bringing back the policy to the October and November meetings.

SPP Director Irene Dimitry | © *RTO Insider*

Based on the feedback already received, Lucas said SPP will focus on just two of the policy's three paths: HILLs and high-impact large load generation interconnection assessments (HILLGAs). The latter are generation and load studied on the fast track and pairing generation with a HILL or a conditional HILL (CHILL).

Lucas proposed that SPP continue to work on CHILLs, which has received most stakeholder questions. These loads would be interconnected to the grid quickly but would be expected to transition to firm service within five years.

"We would have a little more time to work through that with stakeholders and make sure that they're all comfortable with that," Lucas said. "We think we have a pretty good product at the end of the day to make the SPP region more attractive for entities who are looking to … connect large loads."

Board Vice Chair Ray Hepper, leading the meeting in place of Chair John Cupparo, reminded the board and stakeholders that it was an "executive order" from the chair in May that asked for staff to return in August with a large load integration policy.

"Not only did they bring us a proposal, they brought us tariff language; that is an incredible accomplishment," Hepper said, not mentioning that the proposal is about 500 pages long. "Everybody agrees we need to move quickly. We don't want to slow this proposal down, but a little more time is helpful. This is an important initiative for lots of the [load-responsible entities], and it's important for lots of the states." ■

SPP Board/Members Committee Briefs

Directors Award RTO's 7th Competitive Project to SPS

KANSAS CITY — SPP has approved its seventh competitive project under FERC Order 1000, a 19-mile, 115-kV new transmission line with an estimated cost of $45.5 million.

An independent industry expert panel (IEP) selected incumbent Southwest Power Service Co. as the project's designated transmission owner. Invenergy, the only other bidder on the project, was designated as the alternate TO.

The RTO's Board of Directors approved both selections during its Aug. 5 quarterly meeting. The Members Committee provided a unanimous advisory vote, with seven abstentions.

SPS submitted a bid of $21.1 million to build the line. Invenergy's bid came in at $36.3 million.

The IEP unanimously endorsed SPS as the designated TO. It found the utility's bid would significantly lower the project's lifetime cost ($21.8 million to $51.9 million) and that it was superior in identifying a construction and procurement plan. The panel gave SPS a 1,052.2 score, more than 200 points better than Invenergy (829.62), aided by incentive points awarded by SPP for meeting detailed project proposal requirements.

"You'll see a wide difference between points," IEP Chair Tom Bozeman said as he shared the results with the board. "It was a relatively obvious, easy slam-dunk decision."

The IEP's *final report* included a request that bidders improve the quality of their reports, a new addition from the panel.

"The intention was to reinforce a well-organized quality proposal, because that's what we're looking at. That's what we're comparing," Bozeman said. "It's important for the bidders to have the information that's requested and needed in their proposals because we're not asking for additional information later."

SPP staff determined the Lynch-Medanos project would help maintain NERC compliance and allow the continued ability to serve SPS load in New Mexico with adequate voltage levels. It was approved in 2024 as part of the latest Integrated Transmission Planning assessment, resulting in a $7.65 billion portfolio. (See *SPP Board Approves $7.65B ITP, Delays Contentious Issue*.)

The project has a Dec. 1, 2028, in-service date.

SPP's Casey Cathey answers questions from the flood during the board's August meeting. | © *RTO Insider*

1st Surplus+ Initiative Approved

The board approved a tariff revision (RR693) that would accelerate the addition of new generation by quickly adding shovel-ready incremental capacity at existing generating sites. The first Surplus+ initiative is among a suite of products that would end when the Consolidated Planning Process begins in 2026. (See related story, SPP Celebrates its Novel Consolidated Planning Process.)

Under the proposal, priority requests would be queued higher than study clusters that haven't started. The process would be conducted on an accelerated time frame, not subject to waiting for open seasons or processing as part of a cluster or from needs driven by other requests.

Assuming FERC approval in October, the first requests would be submitted for a 90-day system-impact study, with the first generator-interconnection agreements issued by April 1, 2026.

The Advanced Power Alliance appealed the tariff change to the board, asking it to reject three modifications made by the Markets and Operations Policy Committee in July: expanding eligibility to include facilities that retired in the past five years, assigning Surplus+ requests higher queue priority than requests in the 2024 studies, and removing key guardrails designed to limit facility expansion.

As an alternative, the organization asked that the board either impose a one-time participation limit per existing facility or include an explicit sunset clause in the tariff filing.

"This proposal is intended to serve as a short-term mechanism to facilitate modest incremental capacity additions, not provide an alternative path to interconnection long-term," APA said in its comments. "The continued undermining of established processes to interconnect in SPP adds risk to developers who have a record of investing billions in the region."

In response, board member Stuart Solomon amended staff's motion to include a direction that staff modify the language to make the process available once per generating facility or applicable retired generator before it is filed with FERC.

"This is an innovative proposal that provides another tool for [load-responsible entities] to meet their resource adequacy requirements," he said.

Members endorsed the amended revision 15-5, with two abstentions. The APA, EDP Renewables, Electric Cooperatives of Arkansas, the Natural Resources Defense Council and Pine Gate Renewables opposed the measure.

The board also approved RR689, which addresses a market inefficiency that allowed participants to exploit electrically equivalent settlement location (EESLs) to acquire transmission congestion rights (TCRs) at no net cost, despite real congestion costs in the day-ahead market. The policy establishes a systematic review to detect and prevent manipulative TCR bidding behavior by denying portfolios with offsetting EESL path bids.

Future suspicious activity will be flagged for monitoring and potential violations referred to the Market Monitoring Unit. The MMU supports the policy, calling it "manipulative behavior."

Nickell: 'Have to Move Faster'

SPP CEO Lanny Nickell thanked the Strategic Planning Committee for putting together a task force, headed by board member Irene Dimitry, to review and improve the grid operator's selection process for competitive projects.

"Some of you have heard me lament over and over that I don't like the fact that it takes so long to go through that process, particularly in today's environment, when we need reliability faster than we've ever needed before," he said. "Transmission is a big part of helping us improve our reliability."

Under the RTO's transmission owner selection process, staff will solicit requests for proposals once a project has been approved by the board. Qualified participants have until June 30 of each year prior to the selection process to submit their applications.

An independent panel of industry experts then reviews, ranks and scores proposals during a confidential process. The results are announced during board meetings.

Tx Costs Exceeding Estimates

Noticing the consent agenda included approval of 11 transmission projects with costs outside the +/- 30% acceptable band, board member Solomon asked staff how deep its and the Project Cost Working Group's analysis goes in making the determinations. He also asked whether staff have considered reasons for the cost increases.

SPP's Casey Cathey, vice president of engineering, said the PCWG looks at "each and every" out-of-band project and discusses the reasons for the new estimates with the project's owner.

"Staff also validates those reasons," Cathey said. "There's certain things that this staff doesn't have privy to … so it depends on how deep you want to go, but we do validate each reason."

SPS' 765-kV project was pulled off the consent agenda for a separate discussion. (See related story, SPP Board Sets Aside 765-kV Costs, Large Load Policy.) However, the Elm Creek-Tobias competitive project remained, despite a revised cost estimate of $291 million that almost doubles the original $148 projection.

Staff said the discrepancy stems from an omission in the original estimate, which included only conceptual projections for the project's non-competitive portion. SPP re-evaluated the project and determined it remains the most effective solution to address winter weather transfer needs between Nebraska and Kansas.

The board approved the project, an 85-mile 345-kV transmission line on the western side of SPP's footprint, in October 2024. The project includes four components: terminal upgrades at each end, a non-competitive segment and a competitive segment to be built. (See SPP Board Approves $7.65B ITP, Delays Contentious Issue.)

The consent agenda also included:

- The 2026 Operating Plan, which serves as the foundation of the 2026 budget. The plan focuses on each business area within the RTO and aligns long-term strategy with 2026 initiatives. The Finance and Strategic Planning committees approved the plan during a joint meeting in July.
- Nominations to the Strategic Planning Committee. (See "SPC Increases Membership," SPP Strategic Planning Committee Briefs: July 17, 2025.)
- Scope revisions to the Finance Committee, Strategic Planning Committee, and the Future Grid Strategy Advisory Group. ■

— Tom Kleckner

Constellation Optimistic About Nuclear-friendly Federal Policies

Top Commercial Reactor Operator Reports Solid Results and Outlook

By John Cropley

Constellation Energy said it is riding high on policy and market support for nuclear energy as it announced its *second-quarter results*.

"The passage of One Big Beautiful Bill [Act] was an undisputed win for nuclear power," CEO Joe Dominguez said during an *earnings call* with analysts Aug. 7.

More than that, the passage of OBBBA was a demonstration of bipartisan support for a power-generation technology that for many years was out of favor with many Americans. Dominguez noted the bill, which passed with only Republican votes, expands tax credits created by the Inflation Reduction Act, which was passed with only Democratic votes.

"It's one of the only things the two bills have in common, is that it supports existing and new nuclear plants," he said.

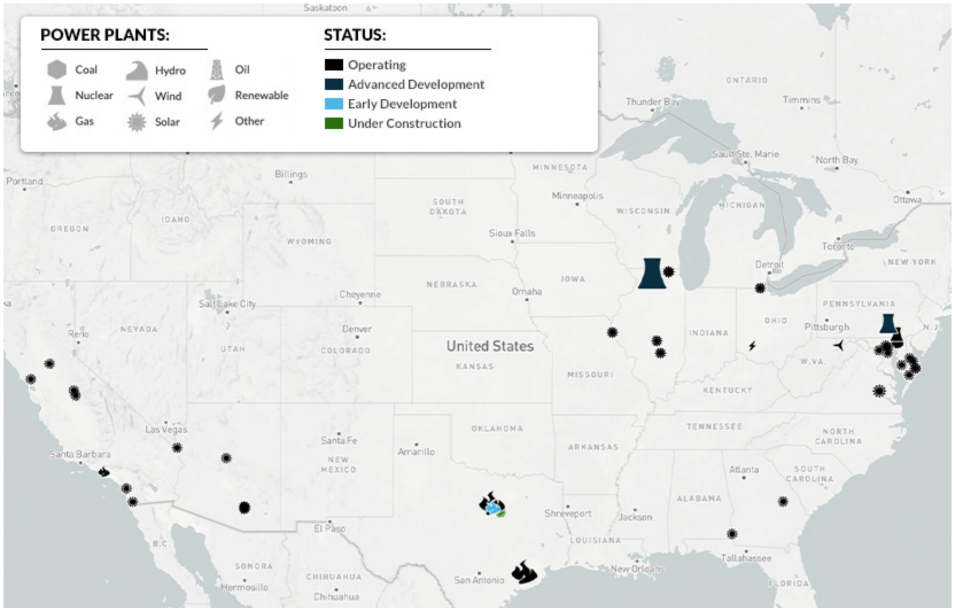
He added that negotiations have reached late stages with one potential power customer and middle stages with others interested in clean, reliable electricity.

"But most importantly, from my perspective, we're seeing a continued acceleration of interest from a growing number of entities," Dominguez said.

An analyst asked if Constellation's nuclear strategy has changed in light of OBBBA.

Evolution seems likely, Dominguez said, rather than abrupt and sharp changes — particularly with small modular reactors, a potential game changer for the industry. Not all of the dozens of SMR designs being advanced will work or be commercially viable, he said.

"But we've got a pretty good bead on who we think the winners are going to be," he said. "I feel better with the passage of each week in terms of better understanding the cost structures and the time to complete the work. And so I would say that our confidence is growing, but it's growing incrementally, not in terms of major step changes."



Constellation Energy is the nation's largest commercial nuclear power operator, but its portfolio includes a range of other technologies. | *Yes Energy*

Dominguez said co-location of new SMRs with Constellation's existing fleet of large reactors just makes sense — the sites have suitable land, an experienced workforce and a supportive community.

He singled out New York for its recent policy moves to support existing and new nuclear generation — announcing plans to develop at least 1 GW of new advanced nuclear capacity, moving toward a decision to extend to 2049 the zero-emissions credits that subsidize Constellation's four in-state reactors and collaborating with the company to seek federal funding for advanced nuclear development at the Nine Mile Point plant, which has two older-generation reactors. (See *N.Y. Makes Case for Extending Nuclear Subsidies to 2049* and *N.Y. Pursuing Development of 1-GW Advanced Nuclear Facility*.)

"It's early innings on this work, but I think it is going to be a signpost for other states, and I'm excited for the opportunities to expand nuclear in places like Maryland, Illinois, Texas and Pennsylvania," Dominguez said.

In other updates:

- Constellation's acquisition of natural gas power generator Calpine has cleared most of its key regulatory reviews and is targeted for closure before the end of this year.
- Big Tech is not the only sector seeking clean energy. Many customers other than data centers are interested in nuclear power.
- Comcast is among the newest of these customers and has committed to a significant energy transaction that will help support a nuclear reactor uprate.
- The engineering process is complete on potential uprates of other reactors, and Constellation says it hopes to partner with customers on these projects as well.
- Constellation and GridBeyond are collaborating on an AI-powered *demand-response program* in the PJM grid that will allow customers to cut their peak energy costs while helping the market maintain system reliability.

Constellation reported second-quarter 2025 income of $833 million ($2.67/share) on revenue of $6.1 billion, which compares with $809 million ($2.58/share) on $5.48 billion a year earlier.

Its stock price closed 0.6% lower Aug. 7. ■

Duke Highlights Legislative Wins in Q2 Earnings Call

By James Downing

Duke Energy reported earnings of $1.25/share for the second quarter, and CEO Harry Sideris told analysts Aug. 5 the company also came out ahead with state and federal legislation.

With Republicans in control of both houses, the North Carolina legislature overrode a veto from Gov. Josh Stein (D) on July 29 and made the Power Bill Reduction Act (*SB266*) law, which cuts the state's greenhouse gas emission-reduction commitments.

"As we ramp up generation investments to meet accelerating load growth, this legislation allows for annual recovery of financing costs for new baseload generation, supporting our credit profile and minimizing costs to customers," Sideris said.

Stein's veto statement argued that the bill would lead to higher costs for customers, as Duke and other load-serving entities have to burn more expensive fuel to generate power in the coming decades.

"Recent independent analysis of Senate Bill 266 shows that this bill could cost North Carolina ratepayers up to $23 billion through 2050 due to higher fuel costs," Stein said. "This bill not only makes everyone's utility bills more expensive, but it also shifts the cost of electricity from large industrial users onto the backs of regular people — families will pay more so that industry pays less. Additionally, this bill walks back our state's commitment to reduce carbon emissions, sending the wrong signal to businesses that want to be a part of our clean energy economy."

The law eliminates a requirement for Duke and other generators to cut emissions by 70% from 2005 levels by 2030. Sideris highlighted language that authorizes Duke to recover generation investments using construction work in progress (CWIP) adders, meaning it can collect money from ratepayers when plants are being built.

Why This Matters

With positive earnings and favorable regulatory environments in its states, Duke is moving ahead with several large investments and agreements.

But Sideris said the law will make the state more attractive for growth and help Duke meet the higher demand that comes with new customers, including new *data center* investment of $10 billion by Amazon Web Services.

"It gives us some credit help with CWIP being able to recover annually," he added. "But … our plan is still along the same lines as the all-of-the-above [approach] that we filed in the multiple [requests for proposals] that we've done. We'll be … really looking at all resources that can support the growth that we're seeing in North Carolina, and this bill just helps us manage that but also manage the customer affordability portion."

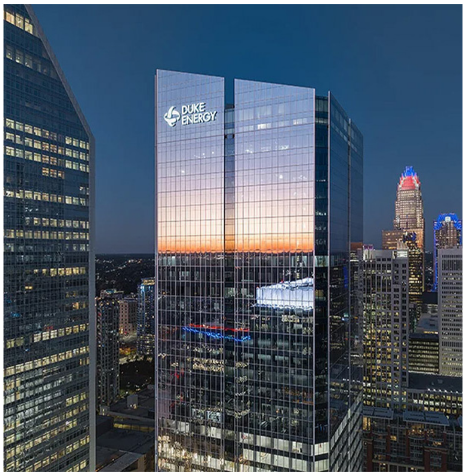
On the company's previous earnings call, Sideris was critical of a draft of the One Big Beautiful Bill Act that would have stripped tax credits for nuclear plants, but that language did not make it into the final law. (See *Budget Bills Would End Energy Tax Credits Early, Claw Back Other Funding*.)

"On the federal side, the preservation of nuclear production tax credits in the final budget reconciliation bill was a significant win for our customers," Sideris said. "Only well-run, cost-efficient reactors are eligible to receive the credit. Our 11-GW nuclear fleet is the largest regulated fleet in the nation and earned $500 million of PTCs last year."

In Ohio, Duke counts the enactment of House Bill 15 as a victory because it eliminates the electric security plans, which had governed utilities there for more than a decade, Sideris said. (See *Ohio Governor Signs Utility Law Aimed at Enhancing Competition*.)

In Florida, Duke *announced* a deal with Brookfield Asset Management, which will acquire a 19.7% share of Duke Energy Florida for $6 billion that will support a $4 billion increase in the utility's five-year capital plan.

Duke is also preparing some regulatory filings that will seek to combine its utilities in the Carolinas, which have maintained some separation since the company bought Progress Energy more than a decade ago. It plans to file requests with FERC and both the North Carolina and South Carolina commissions this month.



| *Duke Energy*

In addition to large customers, the Carolinas are seeing demand grow as more people move there, and the company has plans to build 8 GW of new dispatchable supply by 2031 at all of its utilities, including 1 GW of uprates at existing plants and new generators, Sideris said.

"With turbines secured under our framework agreement with GE Vernova and gas supply contracted, we are confident in meeting the in-service timelines we have laid out for these new units," Sideris said.

While uprates at existing nuclear plants are a firm part of its plan, Sideris said Duke would not commit to building new units until the risks, supply chains and workforces are addressed for both traditional and small modular reactors.

"We're also going to have to have overrun protection from the federal government or others to be able to protect our customers and our investors from any overruns on these projects," Sideris said. "And then lastly, we're going to have to have a means to make sure that we're protecting the balance sheet as we're building these facilities. So, until we get those items resolved, we're still looking at solar, gas, and upgrading and getting everything that we can out of our current assets." ■

Google Strikes Demand Response Deals with I&M, TVA

Data Center Loads Could be Reduced During Peak Demand Periods

By John Cropley

Google has reached agreements with Indiana Michigan Power (I&M) and the Tennessee Valley Authority to reduce power use by its data centers during critical periods.

The company *said* Aug. 4 that it has been working to bring demand flexibility to its data center fleet but the new demand response agreements are the first time it is targeting machine-learning workloads to accomplish this.

In a demonstration project with Omaha Public Power District, Google reduced the power demands of its machine-learning workloads during three grid events in 2024. This set the stage for similar efforts in other regions.

The rise of data centers, with their 24/7 demand for large amounts of electricity, has left the electricity sector and policymakers excited about the lucrative potential they represent and anxious about the challenge of realizing that potential: There appears not to be enough capacity to meet the highest projections of peak demand and no way to add capacity quickly and inexpensively.

A *Duke University study* released earlier in 2025 addressed this quandary by looking at the kind of arrangement Google is announcing with the two utilities: temporary curtailment of load.

As much as 126 GW of new demand could be handled with existing generation, the authors concluded, if data centers cut their energy use by as little as 1% during peak periods. (See *US Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

Google said it is working to develop this ability to reduce or shift power demand during certain hours and certain times of the year.

Along with the benefits to the grid and to grid operators, DR has the advantage of speeding up the interconnection process and bridging the gap to long-term clean energy solutions, Google said.

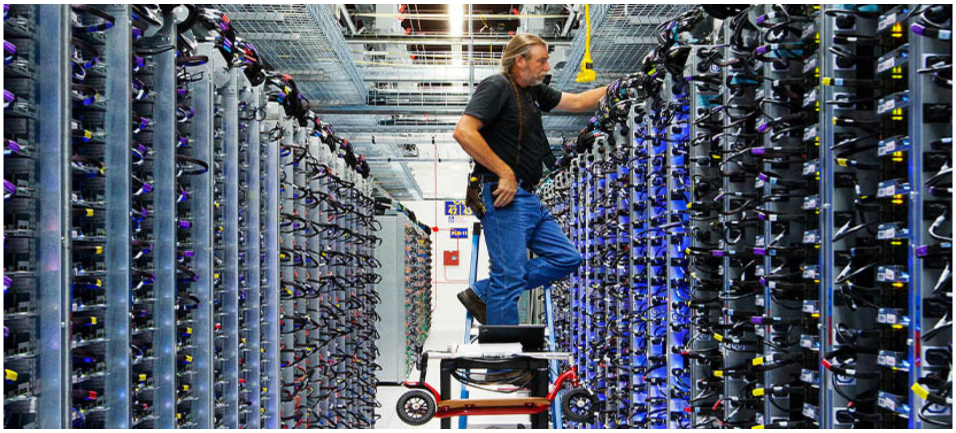
The company said its first such efforts involved shifting non-urgent computing tasks such as processing videos for YouTube, and it sees significant further opportunity through development of DR for machine-learning workloads. This will let it grow artificial intelligence capabilities even in regions where generation and transmission are constrained, it said.

Google said demand flexibility will be possible only in certain locations in these early stages and faces a finite potential, given the high level of reliability the company needs for some of its services. It expects DR to be part of a portfolio of solutions that includes new generation and transmission.

Contract Details

I&M submitted the Google contract to the Indiana Utility Regulatory Commission on July 30 (*46276*).

It pertains to Google's new data center in Fort Wayne and is similar to programs currently available to the utility's residential and commercial/industrial customers, I&M President Steve Baker *said in a news release*. Google announced the $2 billion Fort Wayne project in April 2024; I&M energized it seven months later.



A technician works at a Google data center. | *Google*

Why This Matters

The arrangements would reduce the need for infrastructure investments to accommodate the high energy demand of data centers.

"Google's ability to leverage load flexibility will be a highly valuable tool to meet their future energy needs," Baker said.

It would also help I&M. The utility said that if the IURC approves the contract, "this agreement will reduce I&M's long-term generation requirements and financial commitments to benefit all I&M customers."

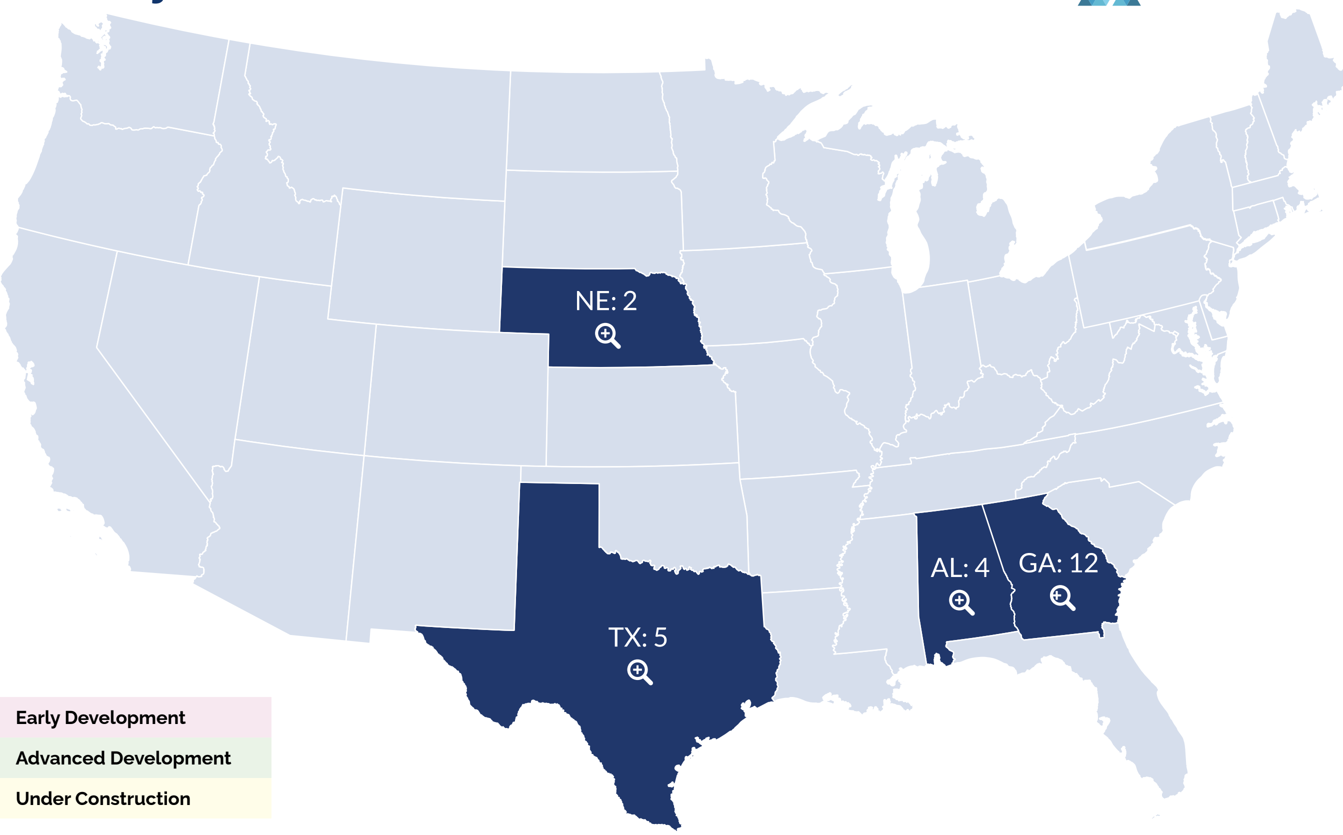
In its petition to the IURC, I&M said the contract has two key aspects: a clean capacity agreement by which Google will transfer to I&M long-term accredited capacity from clean energy resources that the utility will use to meet a portion of its state retail capacity obligations as part of its PJM fixed resource requirement plan, and "a custom demand response offering" to reduce I&M's peak load in times of high demand, thereby reducing the utility's capacity obligation and transmission requirements to serve its customers.

Because the clean capacity agreement will be used to meet its load obligation for all Indiana customers, I&M proposes to recover associated costs in the same way it recovers capacity-related purchase costs: through its Resource Adequacy Rider. It also proposes to recover through the rider any demand response credits provided to Google.

Two days after I&M submitted the petition, the Citizens Action Coalition of Indiana petitioned to intervene, citing the potential impact on rates charged to residential customers and services provided to them. ■

T&D Projects Added in the Past Week

YES ENERGY



- Early Development
- Advanced Development
- Under Construction

New Line | New Substation | Line Upgrade | Substation Upgrade

Project Name	Holding Company or Parent Organization	Utility	Voltage (kV)	In Service Year	Endpoint 1 / 2
Pittman Road - West Point (APC) Line Rebuild	Southern Company	Alabama Power	115	2031	AL / GA
Auburn University - McLemore DS Line Reconductor	Southern Company	Alabama Power	115	2030	AL / AL
Farley (APC) - Tazewell New Line	Southern Company	Alabama Power	500	2030	AL
Martin Dam - North Auburn Line Reconductor	Southern Company	Alabama Power	115	2030	AL / GA
Dyer Road - South Coweta Line Rebuild (Mcintosh Trail)	Georgia ITS	Georgia ITS	115	2032	GA / GA
Bowen - Brandon Farm Road New Line	Southern Comapany	Georgia Power	230	2032	GA / GA
Fortson - Talbot County #2 Line Rebuild	Georgia ITS	Georgia ITS	230	2031	GA / GA
East Point - College Point Tap and Morrow - Forrest Park	Southern Company	Georgia Power	115	2031	GA / GA
Forsyth 2 - Stokes Store Road - Jackson Line Reconductor	Southern Company	Georgia Power	115	2031	GA / GA
Bowen - Pegamore Line Rebuild	Southern Company	Georgia Power	230	2031	GA / GA
Cliftondale - Ono New Line	Southern Company	Georgia Power	230	2030	GA / GA
Yates - North Coweta Line Rebuild	Southern Company	Georgia Power	115	2030	GA / GA
Barnesville Primary Substation Upgrade	Georgia ITS	Georgia ITS	230	2030	GA / GA
Yates - Line Creek Line Rebuild (Green and Red)	Georgia ITS	Georgia ITS	230	2030	GA / GA
Kia Motors - PIttman Road - LaGrange #11 Line Rebuild	Southern Company	Georgia Power	115	2030	GA / GA
Union City Line Trap Replacement	Georgia ITS	Georgia ITS	500	2030	GA / GA
Pierce County Energy Center Network Upgrade	Nebraska Public Power District	Nebraska Public Power District	345	2031	NE
Pierce County Energy Center Network Upgrade	Nebraska Public Power District	Nebraska Public Power District	345	2029	NE
Josephine Substation New	Rayburn County Electric Coop	Rayburn County Electric Coop	138	2025	TX
Explorer Switchyard Upgrade	Rayburn County Electric Coop	Rayburn County Electric Coop	138	2025	TX
Commerce South Substation upgrade	Rayburn County Electric Coop	Rayburn County Electric Coop	138	2026	TX
Brinker Substation Phase 2	City of Denton TX	Denton Municipal Electric	138	2025	TX
Underwood New Substation	City of Denton TX	Denton Municipal Electric	138	2025	TX

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

Company Briefs

Woodside Energy Exits Proposed Hydrogen Production Facility

Woodside Energy last week announced it will not move forward with its proposed hydrogen production facility in Oklahoma.

In a statement, the company said it decided to exit the proposal because of ongoing challenges in the lower-carbon hydrogen industry, including cost escalation and lower than anticipated hydrogen demand.

The project involved building a 290-MW facility producing up to 90 tons of liquid hydrogen for the heavy transport sector, according to the state Department of Commerce.

More: *KOSU*

Radiant Signs Deal to Supply Microreactor for U.S. Military Base

Radiant Nuclear announced last week it signed an agreement to deliver the first-of-a-kind unit of its microreactor to a U.S. Air Force military base in 2028. The value of the contract and the location of the USAF base were not disclosed.

Radiant's Kaleidos design is a 3-MW transportable microreactor and can produce power within 48 hours of delivery. The reactor has a five-year fuel cycle and a 20-year service life.

Radiant has previously received funding awards from the Department of Defense to evaluate the integration of microreactors at the Hill Air Force Base in Utah.

More: *Neutron Bytes*

Federal Briefs

Popular EPA Database in Limbo amid Science Cuts

EPA last week said it would stop updating research that hundreds of companies use to calculate their greenhouse gas emissions after the agency suspended the database's creator because he had signed a letter criticizing the Trump administration's approach to scientific research.

The researcher, Wesley Ingwersen, is leaving EPA to pursue his work at Stanford University. Ingwersen was one of 139 agency employees suspended and investigated after signing the June letter, which charged that Trump's policies "undermine the EPA mission of protecting human health and the environment."

Ingwersen led work on a statistical model that combines environmental and economic data to calculate the carbon footprints of a range of goods and services. The open-source data sets, which are the third most viewed of more than 281,000 federal data sets on data.gov, help companies understand the greenhouse gases generated by each step in their supply chains. The data sets will remain publicly available but will not be updated to reflect the current state of the economy.

More: *The New York Times*

EPA Dissolves Union Contract, AFGE Says

EPA has unilaterally dissolved a collective bargaining agreement with members of the union that represents its workers, the American Federation of Government Employees (AFGE) said last week.

The agency's move comes after a similar decision at the Department of Veterans Affairs last week. Both actions come after a federal court sided with the Trump administration on whether it can rescind such contracts.

More: *The Hill*

National/Federal news from our other channels

Dept. of Interior Launches Overhaul of OSW Regs — NetZero Insider

RF Speaker Promotes AI in Corporate Communications — ERO Insider

NERC Plans to Register 720 IBRs by May 2026 — ERO Insider

NERC Posts IBR Standards for Comment — ERO Insider

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

State Briefs

ALABAMA

PSC Approves Alabama Power Purchase of Autauga County Plant

The Public Service Commission last week approved Alabama Power's purchase of the Lindsay Hill natural gas plant in Autauga County.

The company said it needs roughly 1,200 MW in new power capacity by the end of the decade, due in part to the growth of data centers, and estimates it will have surplus capacity until 2028.

The PSC also approved the company's request to increase monthly residential rates by $3.32 to offset the cost of acquiring the plant.

More: *Alabama Reflector*

ARIZONA

APS to Walk Back Clean Energy Goals

Arizona Public Service last week said it will walk back its clean energy commitments as the federal government curtails tax credits for renewable energy projects.

Company CEO Ted Geisler said in an earnings call that the company would move from a "zero-carbon" approach to a "carbon-neutral" one by 2050. That means the utility will aim to balance its emissions to ensure it does not add new greenhouse gases to the atmosphere, rather than eliminating them entirely. APS will also remove its near-term targets, which included a commitment to building generation resources such that 65% of its energy mix was supplied by clean sources by 2030. The utility will also push back its goal to exit coal-fired generation by 2031.

More: *KJZZ*

CALIFORNIA

San Francisco Fast-tracks All-electric Standard for Renovations

San Francisco has moved to ensure that substantial renovations in existing buildings are all-electric.

The city and county's Board of Supervisors voted 11-0 to pass the All-Electric Major Renovations Ordinance, a building standard that will apply to commercial and residential structures.

If enacted, the ordinance will affect projects that are similar in scope to new construction, including additions as well as renovations that remove mechanical systems.

More: *Canary Media*

ILLINOIS

ComEd Lobbyist Sentenced to Year in Prison for Role in Bribery Scheme

Longtime Chicago lobbyist Jay Doherty was sentenced to a year and a day in prison last week for his role in a bribery scheme between his biggest client, utility Commonwealth Edison, and former House Speaker Michael Madigan.

For eight years, Doherty agreed to use his consulting company as a pass-through to pay several political allies of Madigan's, who did nothing for ComEd but received monthly checks ranging from $4,000 to $5,000. Two separate juries have found the payments were the cornerstone of a larger bribery scheme aimed at influencing Madigan while the utility pushed for major legislation.

Doherty is scheduled to report to prison on Sept. 30.

More: *Capitol News Illinois*

IOWA

Henry County Enacts Commercial Solar Moratorium

The Henry County Board of Supervisors last week voted unanimously to approve a 12-month moratorium on new large-scale solar energy and battery storage projects.

The moratorium is intended to give the county time to review and update its zoning rules for alternative energy development. The freeze will remain in effect until Aug. 1, 2026, unless the board lifts it sooner after making ordinance changes. Supervisors also reserved the right to extend the moratorium if needed.

The board removed its wind moratorium at its Aug. 7 meeting. The moratorium went into effect April 2, 2024, and was extended on Jan. 30.

More: *Southeast Iowa Union*

KENTUCKY

1st US Commercial Uranium Enrichment Plant Signs Lease

A lease to build the first U.S.-owned, privately developed uranium enrichment facility in the country was signed in western Kentucky last week.

General Matter, a California-based company, plans to build a proposed $1.5 billion facility on the 100-acre parcel leased from the DOE on the site of the former Paducah Gaseous Diffusion Plant in McCracken County. The lease, according to a DOE release, entitles General Matter to "a minimum of 7,600 cylinders" of spent fuel sitting at the former PGDP site.

The company plans to pursue Nuclear Regulatory Commission licensing for enrichment and aims to enrich uranium before 2030.

More: *Louisville Public Media*

MONTANA

DEQ Approves Gas Plant Operations After. Legal Challenges

The Department of Environmental Quality last week found no significant impacts from greenhouse gases produced by NorthWestern Energy's Yellowstone County Generation.

The DEQ announced the findings in a final analysis, marking the likely conclusion to a yearslong challenge over how operations could negatively impact the health and the environment.

In January, the state Supreme Court allowed an initial state-issued permit for the plant to stand after a 2023 legal challenge by environmental groups prompted a lower court's blocking of the permit. However, the court directed the DEQ to further evaluate greenhouse emissions and lighting effects from the plant, finding the agency's initial evaluation of impacts roughly four years ago insufficient. The most recent assessment by the DEQ found the 175-MW plant would produce around 695,000 metric tons of carbon dioxide emissions per year, which equates to 1.38% of the state's annual carbon dioxide emissions.

More: *The Billings Gazette*

NORTH DAKOTA

PSC Approves Basin Electric Power Cooperative Natural Gas Plant

The Public Service Commission last week approved Basin Electric Power Cooperative plans for a natural gas power plant that could become the state's largest single source of electricity.

The $4 billion project is planned to be built in two sections, with the first starting to generate power in 2029 and the second in 2030. Each unit will have a capacity of 745 MW.

More: *North Dakota Monitor*

OHIO

Rivian Sues BMV over Prohibition on Direct Car Sales

Rivian is suing the state's Registrar of Motor Vehicles, saying Ohio law prevents it from selling cars in the state while letting Tesla do precisely that.

Rivian filed the lawsuit Aug. 4 in U.S. District Court in Columbus, asking the court to determine that the provision of the law violates the Fourteenth Amendment equal protection rights of Ohio consumers. According to the lawsuit, a 2014 law allows the Registrar of Motor Vehicles to deny a license for a motor vehicle dealer to "a manufacturer, or a parent company, subsidiary or affiliated entity of a manufacturer. Shortly thereafter, and to cut off future competition, OADA (the Ohio Automobile Dealerships Association) lobbied the Ohio General Assembly to enact a law that would prohibit the direct-sales-only business model for every manufacturer but Tesla."

No court date has been set, according to federal court records.

More: *The Columbus Dispatch*

OREGON

Gov. Kotek Signs Bill to Address Utilities' Resistance to Solar

Gov. Tina Kotek last week signed a bill into law that aims to address its utilities' resistance to community solar, rooftop solar and other forms of clean energy generation the utility is less likely to own.

The new law gives the Public Utility Commission the power to develop and adopt a framework for carrying out performance-based regulation of utilities. The commission may then use the regulations to provide incentives and penalties to get utilities to bring their operations in line with the public interest, such as developing distributed energy resources, improving operations to reduce costs to ratepayers and reducing greenhouse emissions.

The new law will go into effect Jan. 1, 2026.

More: *pv magazine*

TEXAS

CPS Energy Approves $175M Tx Project

The CPS Energy Board of Trustees last week approved spending $175 million to build 24.5 miles of transmission line as part of the San Antonio South Reliability Project.

The new line is the centerpiece of the $329.1 million reliability project to relieve congestion and improve the grid's long-term resiliency. It will span 50 miles, with CPS responsible for the northern half of the 345-kV line and the South Texas Electric Cooperative responsible for the southern portion.

The route is scheduled to be in service by June 2027.

More: *Houston Chronicle*