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YES ENERGY

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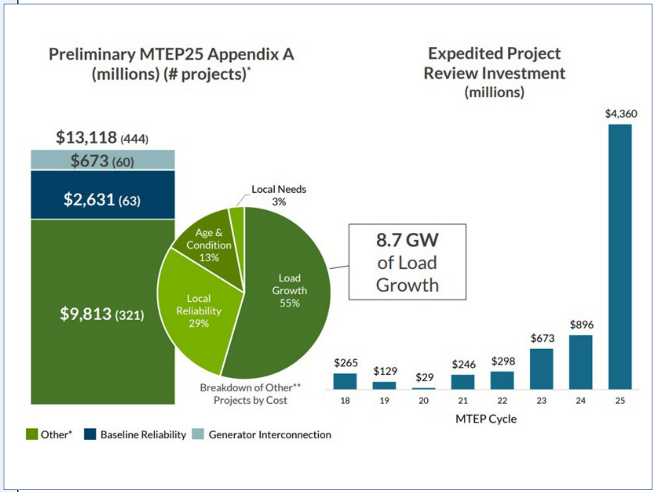
YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

MISO

MISO 2025 Transmission Planning Cycle Rises to $13B



MISO

MTEP 25 now clocks in at $13 billion and contains a record-breaking number of expedited project requests as transmission developers hustle to make room for load growth.

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SPP

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FERC/FEDERAL

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MISO

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After introspection on the New Orleans blackouts, MISO said it will likely work on providing more advance warning to members and regulators when it encounters touch-and-go operating days.

MISO IMM Blasts NERC Long-term Assessment, Says RTO in Good RA Spot (p.37)

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In this week's issue

Storms, Droughts and Day-ahead Markets; Hydropower's Moment to Shine

NOAA Budget Cuts Introduce Uncertainty

By Marshall Moutenot

Marshall Moutenot

Hydropower has been around for a long time. Over its long history, it has become a steady (if not sometimes forgotten) backdrop to the complicated balancing act of providing reliable national energy grids. Dependable, relatively predictable and dispatchable, hydropower now is stepping into a much more dynamic role in energy markets.

U.S. power markets, in particular, are evolving rapidly. The increased penetration of wind and solar power means energy grids have to balance volatility, price cannibalization and variable resources that may cause imbalance in grid frequencies. And while this has driven battery storage in markets with high levels of wind and solar, such as ERCOT and CAISO, there still is a need for long-duration storage and dispatchable power.

Increased weather volatility isn't just grabbing headlines; it's reshaping how we generate and trade electricity. To meet market needs and new policies like the Dxtended Day-Ahead Market (EDAM) in California, hydropower is taking center stage. Its reliable supply is crucial for dynamic, inter-market energy trading.

Why Hydro, Why Now?

With the intermittency of wind and solar now a fundamental part of energy markets, and daily (even hourly — nay, even minute-by-minute) fluctuations common, energy traders need precise generation forecasts for dispatchable resources more than ever. Hydropower, with its storage and ability to quickly adjust output, is uniquely suited for this.

The overlooked challenge in deploying hydropower, as modern energy grids now demand, is that traditional water forecasting methods haven't kept pace with emerging climatic trends and variability.

Conventional forecasts often miss short-term variability for a variety of reasons,

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

including sudden snowmelt, basin-specific behaviors, or unexpected storm impacts. This leaves energy traders with uncertainty, putting resource allocation at risk, and driving (sometimes extreme) fluctuations in price as resources either fall short or overload the market. More precise inflow forecasting doesn't just improve resource adequacy — it enables energy traders to capture value across volatile markets.

Accurate short- and medium-term projections empower traders to position hydro assets strategically across day-ahead, real-time and ancillary service markets, so they can make timing decisions with higher confidence. Enhanced lead-time visibility enables bidding strategies that respond dynamically to shifting local marginal prices (LMPs), grid congestion and imbalance settlement penalties.

By reducing forecast error, traders can better anticipate when to hold back water for peak pricing events or dispatch preemptively during surplus periods, improving P&L performance. Forecast granularity also supports more effective hedging, as predictable inflow reduces exposure to weather-driven volume risk. In intertie-heavy markets like CAISO, EDAM or SPP, forecasting upstream hydrology allows traders to arbitrage regional differences in supply-demand balance, particularly during snowmelt or storm-driven volatility.

AI Forecasting: More Than Just Hype

While the challenge of adapting to a new model of energy trading won't be solved overnight, the step change in artificial intelligence and machine learning, and their respective deployment into streamlining the energy transition for legacy energy grids, bring significant advantages in lessening the impact of intermittent energy resource and climatic volatility.

The soon-to-launch Western EDAM will integrate Pacific Northwest hydropower more closely with California's demanding markets. Accurate, real-time inflow forecasting is quickly shifting from being advantageous to becoming essential.

Uncertainty at NOAA

NOAA's public weather data is invaluable. Unfortunately, recent budget cuts introduce uncertainty about its long-term reliability and resilience, in spite of the heroic efforts by those who remain at the agency.

Crucially, over the longer term, the private sector has the ability to consistently invest in research and development that will further enhance the latest AI forecasting technologies. While we believe a partnership between national forecasting and private solutions is most desirable, reduced funding for public forecasting may see the gap in accuracy between public and private forecasting increase.

Hydro Steps up

Realizing hydropower's full potential starts with accurately forecasting water, an essential first step for navigating the intricate constraints and optimization challenges it faces. Traders who embrace advanced forecasting tools will transform water into a strategic asset while generating enhanced returns.

We're moving beyond an era of simply spinning turbines. Hydropower is now positioned at the forefront of strategic energy trading, proactive market engagement and informed risk management in an increasingly volatile landscape. With enhanced forecasting capabilities, hydropower is confidently embracing this expanded role. ■

Marshall Moutenot is CEO of Upstream Tech, a software company that provides services in the land and water management industries.

Trump Directs Feds to Withdraw from Deal on Snake River Dams

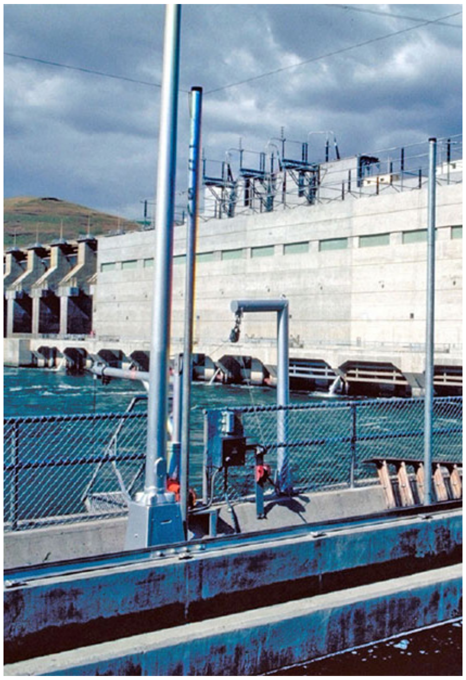
By James Downing

President Donald Trump pulled the federal government out of a deal the previous administration had signed that eventually could have led to breaching several dams on the Snake River in the Pacific Northwest operated by the Bonneville Power Administration.

Trump issued a *memo* June 12 withdrawing from the deal that was entered into after lengthy litigation about four tribes' rights to fish in the river. The deal was opposed by other interests in the region including senior Republicans in Congress. (See *Parties Split on Biden Administration Deal on Snake River Dams*.)

The Biden administration was considering breaching four dams that produce more than 3,000 MW, but it had not made a final decision.

"The negative impacts from these reckless acts, if completed, would be devastating for the region, and there would be no viable approach to replace the low-cost, baseload energy supplied; the critical shipping channels lost; the vital water supply for local farmers reduced; or the recreational opportunities that would no longer be possible as a result of these acts," Trump's memo said.



Little Goose Dam in Dayton, Wash. | *BPA*

The memo directs cabinet secretaries to work to withdraw from the deal and to rescind a supplemental environmental impact statement on the four dams that was published in December 2024.

The Department of Energy said the Biden-era memo of understanding (MOU) required the government to spend $1 billion to comply with commitments aimed at replacing the dams in the Lower Snake River, including possibly breaching them.

"The Snake River Dams have been tremendous assets to the Pacific Northwest for decades, providing high-value electricity to millions of American families and businesses," DOE Secretary Chris Wright said. "American taxpayer dollars will not be spent dismantling critical infrastructure [or] reducing our energy-generating capacity."

The Biden administration signed the deal with the Yakama, Umatilla, Warm Springs and Nez Perce tribes along with the states of Oregon and Washington. The deal supported federal investments in a comprehensive plan for salmon restoration, energy development and transportation infrastructure in the Columbia Basin, said a press release from the Confederated Tribes and Bands of the Yakama Nation.

The MOU from Biden also led to the stay of ongoing litigation under the Endangered Species Act over federal hydropower operations the federal government had consistently lost in, said the Yakama.

"The administration's abrupt termination of the Resilient Columbia Basin Agreement jeopardizes not only tribal treaty-reserved resources but also the stability of energy, transportation and water resources essential to the region's businesses, farms and families," Yakama Tribal Council Chairman Gerald Lewis said in a statement. "This agreement was designed to foster collaborative and informed resource management and energy development in the Pacific Northwest, including significant tribal energy initiatives. The administration's decision to terminate these commitments echoes the federal government's historic pattern of broken promises to tribes and is contrary to President Trump's stated commitment to domestic energy development."

Why This Matters

Trump's move withdraws the federal government from a deal with tribes and states that had stayed longstanding litigation around the dams and their impact on tribal rights to fish the river.

The Yakama Nation is disappointed Trump withdrew from the deal, especially without prior consultation. The way the government has managed the river historically will lead to salmon extinction, Lewis said.

Sen. Ron Wyden (D-Ore.) also blasted the decision to withdraw from a deal two states and four tribes worked hard on only "to have it upended so casually from 3,000 miles away."

"Donald Trump proves yet again his irrational preference for litigation and mindless destruction of actual achievements like this settlement agreement," said Wyden, a senior member of the Senate Energy and Natural Resources Committee. "His approach will make life more difficult for businesses and families by upending meaningful progress to meet regional energy production, water resources and transportation needs while recovering a river and its salmon key to our part of the country."

The National Rural Electric Cooperative Association welcomed the move by Trump, which seeks to ensure the dams are not breached.

"Hydroelectric power is the reason the lights stay on in the region," NRECA CEO Jim Matheson said in a statement. "And as demand for electricity surges across the nation, preserving access to always-available energy resources like hydropower is absolutely crucial." ■

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EPA Proposes Repealing Limits on Power Plant Greenhouse Gas Emissions

By James Downing

EPA proposed repealing greenhouse gas emissions standards for power plants under Section 111 of the Clean Air Act and the 2024 amendments to the Mercury and Air Toxics Standards.

The move was widely expected, as the agency's attempts to regulate emissions in the power sector have gone through several 180-degree reversals over the past decade depending on the party occupying the White House.

"Affordable, reliable electricity is key to the American dream and a natural by-product of national energy dominance," EPA Administrator Lee Zeldin said in a statement announcing the move June 11. "According to many, the primary purpose of these Biden-Harris administration regulations was to destroy industries that didn't align with their narrow-minded climate change zealotry. Together, these rules have been criticized as being designed to regulate coal, oil and gas out of existence."

Why This Matters

EPA's carbon limits on power plants have proven to be a political pingpong ball over the past decade: in vogue when Democrats run the White House and then up for repeal in both of President Trump's terms.

The Minnkota Power Cooperative's Milton R. Young coal-fired power plant in North Dakota | *Minnkota Power Cooperative*

The proposal would repeal the 2015 emissions standards for new fossil fuel-fired power plants issued under President Barack Obama and the 2024 rule for new and existing fossil fuel-fired power plants under President Joe Biden. The 2024 rule was needed because the Supreme Court struck down the first Clean Power Plan in 2022 in *West Virginia v. EPA*, which introduced the "major questions doctrine" as a legal argument limiting regulatory power.

Unlike other air pollutants that have a regional or local impact, the emissions targeted in the rules are global in nature. EPA is proposing that the Clean Air Act require the agency to make a finding that the targeted emissions from fossil fuel-fired power plants are significant in a global context.

"The share of GHG emissions from the U.S. power sector, including CO_2, to global concentrations of GHGs in the atmosphere is relatively minor and has been declining over time," the proposed rule says. "In 2005, U.S. electric power sector GHG emissions comprised 5.5% of total global GHG emissions. This percentage has fallen steadily since then to 4.6% in 2010, to 3.7% in 2015, and comprising 3% of total global emissions by 2022."

Part of that decline is from the rise in GHGs in other countries, with the proposed rule saying that while domestic coal use has declined since its peak in 2007, more coal was burned globally than ever before in 2024.

A major reason that EPA tried to regulate CO_2 in the first place was the Supreme Court's 2007 decision in *Massachusetts v. EPA*, which held it could if it made an endangerment finding on GHGs. EPA is not trying to overturn that endangerment finding, Zeldin said in a press conference unveiling the two proposed rules.

"I don't have anything to announce today as it relates to any proposed rulemaking that may be to come on that topic, and we will update the public as soon as we do have an announcement," Zeldin said.

2024 MATS Amendments

EPA also proposed eliminating the 2024 updates to the MATS for coal and oil-fired power plants, reverting back to 2012 standards that drove a sharp reduction in the covered pollutants.

By 2021 mercury emissions from coal plants were already 90% below pre-MATS levels; acid gas hazardous air pollutant emissions have been cut by over 96%; and emissions of non-mercury metals like nickel, arsenic and lead are down 81%.

EPA said repealing the rule would save $1.2 billion in regulatory costs over a decade, or about $120 million a year.

Reactions to the EPA's proposed repeals were mixed, with Democrats and environmentalists opposing them and Republicans and some industry supporting it.

Electric Power Supply Association CEO Todd Snitchler said repealing the rule will help the power industry meet growing electricity demand, which requires policies that encourage the continued operation of existing power plants and attracting new investment.

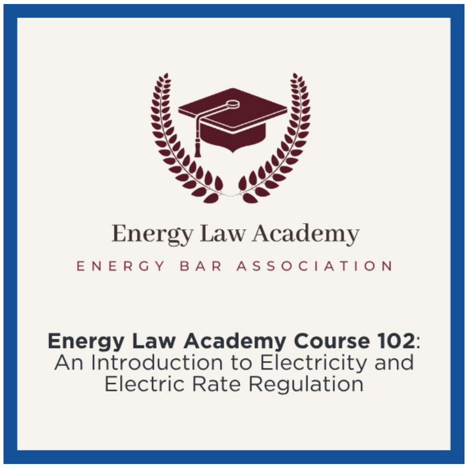
"EPA's rulemaking requiring the use of carbon capture and sequestration technology for existing coal and new natural gas power plants nationwide was unrealistic, unachievable and poorly timed," he said. "The United States is on the cusp of an increased level of demand for electricity, driven in part by the development of artificial intelligence, a resurgence of domestic manufacturing and electrification policies."

The National Rural Electric Cooperative Association said the carbon rule exceeded EPA's authority and disregarded prior Supreme Court decisions, while the MATS updates were costly with minimal benefits that would prematurely retire coal plants.

"Today's announcements are a welcome course correction that will help electric co-ops reliably meet skyrocketing energy needs and keep the lights on at a cost local families and businesses can afford," NRECA CEO Jim Matheson said. "These rules force power plants into premature retirement and handcuff how often new natural gas plants can run. Both of them are textbook examples of a bad energy policy that compounds today's reliability challenges."

Natural Resources Defense Council CEO Manish Bapna said in a statement that EPA is waving the white flag to combating pollution that harms the climate.

"Power plants are the largest industrial source of carbon emissions, spewing more than 1.5 billion tons of greenhouse gases annually," Bapna said. "EPA claims this pollution is insignificant — but try telling that to the people who will experience more storms, heat waves, hospitalizations and asthma attacks because of this repeal. What's more, … EPA is trying to repeal toxic air pollution standards for the nation's dirtiest coal plants, allowing the worst actors to keep poisoning the air." ■



Wright Addresses Recent Orders Keeping Power Plants Open at Hearing

By James Downing

Energy Secretary Chris Wright testified about his department's 2026 budget request at a House hearing where members often pressed him on other issues, including his recent use of the Federal Power Act to keep coal plants from retiring.

"The Trump administration has been laser focused on raising energy costs for Americans, despite what the president campaigned on," Rep Frank Pallone (D-N.J.) said June 10. "And the example came in the last month when your department ordered two power plants burning coal, natural gas and fuel oil to stay online mere days before they were scheduled to shut down for good."

Pallone asked at the hearing of the Energy and Commerce Subcommittee on Energy who had made the decision to keep open Consumer Energy's J.H. Campbell coal plant in Michigan and Constellation Energy's Eddystone natural gas-fired plant outside Philadelphia.

Wright answered that he had; Pallone then quickly moved on to press him about how much money it will cost to keep Campbell running, quoting an estimate from the Michigan Public Service Commission of tens of millions of dollars. Consumers has filed a complaint with FERC seeking compensation from MISO's north and central zones, saying it is tracking costs and will file a specific number at the end of the summer. (See *Consumers Energy Seeking Compensation for Keeping Campbell Open*.)

PJM is taking a different path, working with stakeholders to come up with a way to pay Constellation to implement DOE's order. (See *PJM Board Initiates CIFP Process for Eddystone Compensation*.)

Why This Matters

Following an executive order from the White House, DOE is using the Federal Power Act's 202(c) authority in a new way, keeping plants open regulators had made plans to retire.

Energy Secretary Chris Wright testifies about his department's 2026 budget request at the House Energy and Commerce Subcommittee on Energy. | *House Energy and Commerce Committee*

"Mr. Secretary, your background is in the oil and gas sector, not the electric sector," Pallone said. "So, why do you think that you knew better than the grid operators, utilities and the state regulators to actually try to revive these even though no one seemed to care? Why are you increasing electricity prices for millions of people?"

When it comes to the Campbell plant, Wright said MISO had a blackout just two days after DOE announced that it would keep running this summer, past its retirement initially planned for May 31. (See *MISO Requires Load Shed in New Orleans to Avoid Grid Instability*.)

"MISO [has] the tightest reserve margin we have in the country," Wright said. "You need to be able to keep the lights on. Two days later, the lights went out."

Pallone responded that the outage in New Orleans was a different part of the market. Entergy's territory is in MISO South, which has limited transmission links to its central and north regions and is not subject to cost recovery for running the plant this summer under Consumers' FERC filing.

Rep. John James (R-Mich.) asked about the Campbell plant later in the hearing, specifically asking whether Michigan's and other states' net-zero energy policies had contributed to the situation in MISO.

"Many people at DOE have been in dialogues with NERC and with MISO about these issues, but I think you hit the nail on the head," Wright said. "What do we want? We want to reshore manufacturing to Michigan. We want to bring data centers to Michigan. We need to grow the

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supply of affordable, reliable electricity in Michigan."

Closing a coal plant 15 years before the end of its intended lifespan works against that goal, with Wright saying Michigan officials made the decision for "virtue signaling."

"That's not the best interest of Michigan ratepayers and Michigan citizens," Wright said. "But, yes, utilities get bullied and influenced by state politicians and national politicians that have political agendas around energy that are often not aligned with ratepayers and citizens."

James then made a pitch for Consumers' proposed allocation for the plant, spreading it across 12 other states in MISO's north and central regions so that the contract is not "financially punitive" to Michigan customers.

"MISO is a large organization," James said. "Where this power is dispatched is going to benefit a larger organization and, so, therefore, those costs should necessarily be spread out, as we all have to make sure that we are cooperating to make sure that we keep our power high and keeping our costs low."

Rep. Julie Fedorchak (R-N.D.) used her time for questions to note that she introduced the *Baseload Reliability Protection Act* with seven other Republican co-sponsors that would keep dispatchable power plants open to help the grid meet growing power demand.

"Given that NERC's assessment today is that two-thirds of our systems in the U.S. don't have enough power to meet demand given certain circumstances today, and we're looking at retiring 115 GW of baseload generation, and we're seeing significant demand increases — all of that looks like a huge train wreck to me and to many others," Fedorchak said.

The bill would prohibit the retirement or conversion of dispatchable power generators in areas NERC has identified as having "elevated reliability risks," protect those plants from any fines from noncompliance with environmental rules, and allow DOE to offer grants and loans to support needed plant upgrades and extend operational life. The bill provides exemptions when continued operation poses safety risks or is economically unviable.

Wright said the policies in the bill align with what DOE has been working on to ensure the grid can accommodate new demand from data centers and reshored manufacturing.

"We have a team in our Office of Electricity that's looking at grid reserve margins across the different areas of the country," Wright said. "And we're looking at planned retirements, and then we're going to try to proactively engage with all of them."

"This might be a five-year thing," Fedorchak said. "This might not be forever, but right now, we're behind, so let's stop retiring. Let's make sure we're bringing new resources on as quickly as possible. I stand with my colleagues across the aisle to work on permitting reform, to bring things up as quickly as possible. But meanwhile, we need to keep what we have. That should not be a partisan statement." ■

D.C. Circuit Rejects Kimball Wind's Bid for Substation Reimbursement

By Henrik Nilsson

The D.C. Circuit Court of Appeals denied Kimball Wind's petition to overturn a FERC decision rejecting the wind developer's bid for $5.9 million in reimbursement from the Western Area Power Administration (WAPA) for contributing to a substation expansion in Nebraska.

Specifically, Kimball filed its petition for reimbursement under Section 211A of the Federal Power Act. But to succeed on its petition, Kimball must show its reimbursement request would result in an order for transmission services, which the company failed to do, *according to the June 13 ruling*.

"The key question before us is whether Section 211A authorizes the commission to issue an order directing WAPA to reimburse Kimball Wind for its contribution to the substation expansion," Circuit Court Judge J. Michelle Childs wrote for the three-judge panel. "We agree with the commission that Kimball Wind does not seek an order for transmission services — the only type of order the commission may issue under Section 211A."

In 2016, Kimball entered into an agreement with the Municipal Energy Agency of Nebraska (MEAN) to upgrade an existing wind generation facility. To begin delivering the electricity, Kimball was required to connect to WAPA's transmission network, according to the opinion.

WAPA conducted studies on how to transmit Kimball's electricity output safely and recommended an expansion of the substation. WAPA estimated the expansion would cost $6.5 million and offered to pay $2.2 million. However, MEAN refused to pay the rest, the opinion stated.

Kimball's power purchasing agreement with MEAN required it to deliver energy before the substation was completed. Facing this deadline, Kimball paid approximately $5.9 million and then petitioned FERC for reimbursement, according to Kimball's petition for review.

Kimball sought an order requiring either a cash payment from WAPA or a three-party rate-crediting agreement among WAPA, MEAN and Kimball.

D.C. Circuit Court of Appeals | *D.C. Circuit Court of Appeals*

Notable Quote

"We agree with the commission that Kimball Wind does not seek an order for transmission services — the only type of order the commission may issue under Section 211A."

However, FERC found Kimball did not seek an order for transmission services as required for relief under 211A and that Kimball was not WAPA's transmission service customer, according to the opinion.

In affirming FERC's order, the court said requiring WAPA to reimburse Kimball for the costs associated with the substation expansion does not constitute an order "to provide transmission services," but rather a request to recover construction costs.

"Kimball Wind acknowledges that the only relief it seeks is 'the refund of [its] construction costs,'" Judge Childs wrote in the opinion. "It does not seek a transmission services agreement with WAPA, and it is not currently a party to such an agreement. An order directing WAPA to reimburse Kimball Wind with a cash refund would neither require that WAPA provide transmission services to Kimball Wind nor modify the terms on which WAPA provides transmission services to any other party."

Similarly, Kimball's bid for a three-party rate crediting agreement does not lead to an order for transmission services, the panel wrote.

"On Kimball Wind's petition, neither an order for a cash refund nor an order for a three-party rate-credit agreement would 'require an unregulated transmitting utility to provide transmission services,'" Judge Childs wrote. "The commission, therefore, correctly concluded that Kimball Wind seeks relief that Section 211A cannot provide." ■

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EIA Increases 2025, 2026 Electric Sales Forecast

Commercial Demand Growth in PJM and ERCOT Cited

By John Cropley

The U.S. Energy Information Administration has revised its forecast upward for retail electricity sales — especially in ERCOT and PJM and largely because of anticipated commercial demand.

In its *Short-Term Energy Outlook* released June 10, EIA projected that commercial consumption would increase 3% in 2025 and 5% in 2026. It previously predicted an average of 2% in the two years.

EIA expects total generation this summer to be 1% higher than last summer, also from commercial and industrial load growth, and it expects less generation from natural gas-fired plants because of higher natural gas prices.

The Henry Hub spot price forecast is about \$4/MMBtu for 2025 and \$4.90 in 2026, on average, compared with \$2.20 in 2024, EIA said.

Solar generation is projected to increase from 5% of the U.S. total in 2024 to 8% in 2026 and wind from 11% to 12%.

Natural gas is projected to dip from 42% of the total in 2024 to 40% in 2026, coal from 16% to 15%, and nuclear from 19% to 18%. The outlook for hydro is a steady 6% of the total in all three years.

Breaking it down geographically:

- Electricity sales are expected to increase from 2024 to 2026 in every region except New England, with the largest increase in the West South Central region — from 716 TWh in 2024 to 810 TWh in 2026, a 13.1% jump.
- The same two regions had the lowest and highest all-sector electricity prices in 2024 and are projected to hold the same ranks in 2026: West South Central would rise from 9.73 cents/kWh to 10.16, while New England would rise from 23.06 to 25.79.
- Total power generation by grid region is expected to increase or decrease from 2024 to 2026 by small percentages with two exceptions: PJM is projected to jump 7.6% from 873 TWh to 939, and ERCOT is projected to jump 19.8% from 459 TWh to 550, both from increased renewable, natural gas and coal generation.

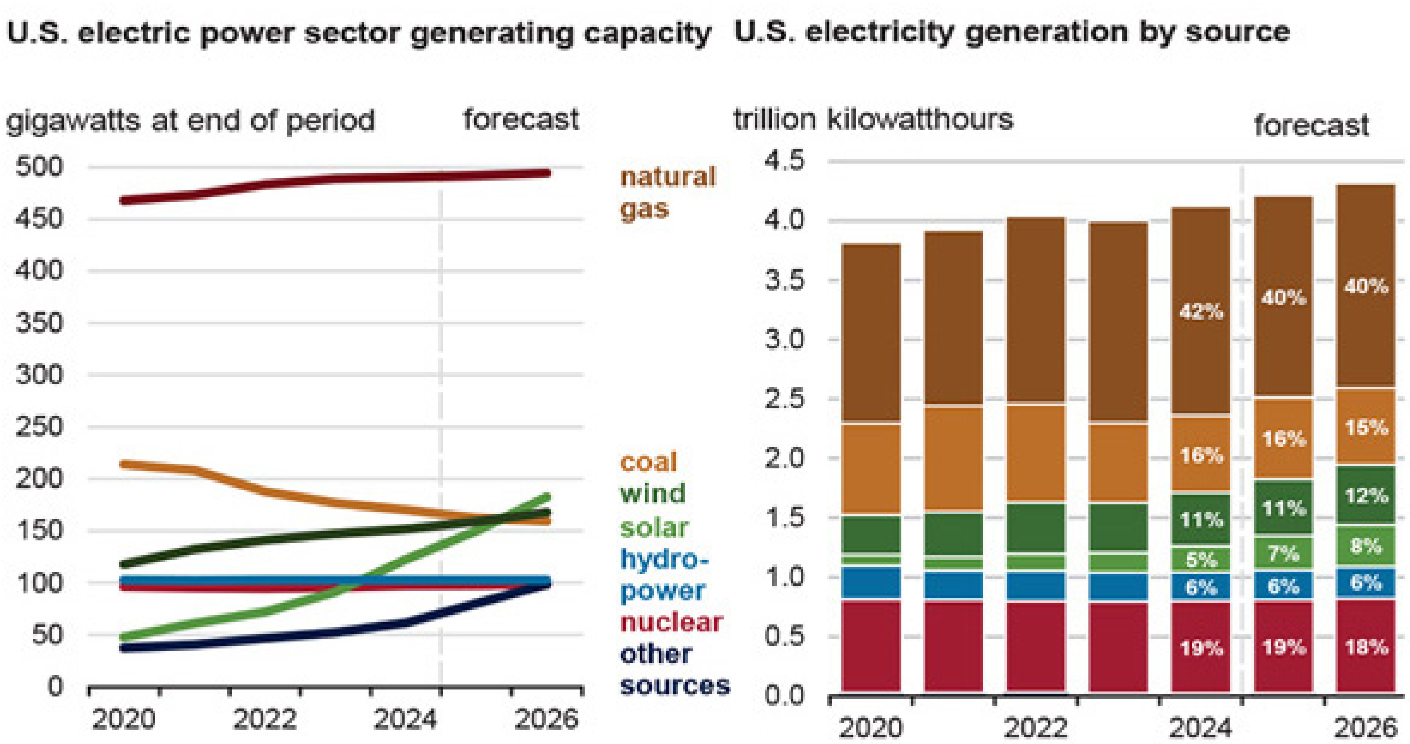
Why This Matters

The projections reflect anticipated growth in commercial power demand in parts of the United States.

Factoring into the report are the economy and the weather. The forecast assumes real GDP growth at an annualized 1.4% in 2025 and 1.7% in 2026.

It also assumes an easing of the trade wars and a reduction in tariffs but notes that future trade policy is a source of uncertainty in the outlook, as is consumer spending, which is projected to grow much more slowly in 2025 and 2026 than in 2024.

EIA also is assuming 2025 will be slightly cooler than 2024, which was warmer than average. This allows a 5% reduction in predicted 2025 cooling degree days and a resulting decrease in electricity demand. ■



The U.S. Energy Information Administration projects renewables will lead a slow increase in U.S. electric generation. | *EIA*

NRG Energy Seeks FERC Approval for LS Power Deal

Company Says its Own Analysis Shows Transaction Won't Harm Market Competition

By James Downing

NRG Energy told FERC that its purchase of generation and the CPower subsidiary from LS Power will not impact competition, despite some overlap in assets in New York and PJM.

The deal announced in May would see NRG buying 13 GW of natural gas-fired power plants from LS along with the demand response aggregator for $12 billion. (See *NRG to Buy 13 GW of Generation Capacity from LS Power*.)

NRG is paying for part of the deal with shares that are estimated to represent 11% of its shares at closing, which would exceed the 10% threshold for functional control in FERC's merger reviews, the company said in the application filed with the commission June 12 (*EC25-102*). To avoid getting over that threshold, NRG will only deliver enough shares to LS Power's shareholders to prevent them from owning 10% or more of NRG's securities.

The rest of the shares owed will be delivered to an independent trustee administering a voting trust, which is similar to a deal FERC accepted back in 2019. The shareholders could only direct the trustee's vote when or if the new NRG issues stock, liquidates the company, enters bankruptcy, agrees to a merger or a few other deals FERC has previously found are limited enough to render them "non-voting securities," the application said.

The deal will double NRG's capacity, with most of LS Power's gas generators being sold located in NYISO and PJM, but the application said standard market screens showed no significant increase in market power.

"The transaction essentially flips the sizes of NRG and LS Power in both New York and PJM, with very little changes in market concentration," said the market power analysis filed with the application.

NRG currently owns 1,201 MW of capacity in NYISO and 2,081 MW in PJM, while LS Power has 1,947 MW and 11,552 MW, respectively, in the two markets. After the deal, NRG would have 2,163 MW in NYISO and 9,463 MW in PJM, while LS Power would have 985 MW and 4,170 MW in the two markets, respectively.

NRG has only a few other assets in the two markets, including a tolling agreement expiring in 2029 for an 895-MW gas plant on Staten Island, and a contract for 175 MW of transmission capacity on the Linden VFT that can ship power between the two markets, which expires in 2028. It also holds 25% of the Bayonne Energy Center in an arrangement that ends in 2027.

The analysis NRG conducted found the deal will not materially change market concentration in either the NYISO capacity market or the New York City submarket. The analysis found similar results for PJM and its submarkets.

The transaction would have LS Power retaining control over 985 MW of the Ravenswood plant in New York City under a tolling agreement, with NRG controlling the rest. The Ravenswood deal will help eliminate any competitive impacts on the New York City submarket, the application said.

In PJM, NRG will wind up with an additional 7,382 MW of additional capacity, but the dynamics of the deal makes the company's Herfindahl-Hirschman Index score of market concentration actually fall slightly, according to the analysis. ■

Why This Matters

The deal will double NRG's capacity, with most of the LS Power gas generators being sold located in NYISO and PJM.

NRG headquarters in Princeton, N.J. | *NRG*

Nuclear Conference Opens amid Momentous Times

Regulatory and Market Shifts Top of Mind as American Nuclear Convenes

By John Cropley

The American Nuclear Society's *annual conference* was well-timed in 2025, as the industry is riding a wave of optimism on a series of recent policy and market moves.

Panelists in the *opening discussions* June 16 noted the stark differences today compared to several years ago, when U.S. nuclear plants were being shut down because they were uneconomical to run.

Speakers also noted the cooperative effort that will be needed to turn this confluence of favorable factors into the increase in nuclear generation that so many of the 1,400-plus conference attendees hope to see.

ANS Executive Director Craig Piercy summed it up in opening remarks: "We've gone from how do we wind down what we have to how fast can we get more? … The challenge now is moving from that intention to that implementation."

He cited indications that tax credits critical to making nuclear power economical will remain in place, and he cited President Donald Trump's May 23 executive orders intended to accelerate and expand development of nuclear generation, in part through *streamlining oversight* by the Nuclear Regulatory Commission. (See *Trump Orders Nuclear Regulatory Acceleration, Streamlining*.)

Why This Matters

For the U.S. nuclear power industry to have a true renaissance, it must overcome the delays and cost overruns that have plagued its recent past.

If any further indication was needed that the 2025 conference came amid a time of momentous change, Trump provided it — firing NRC Commissioner Christopher Hanson, who was appointed by President Joe Biden and formerly chaired the commission.

Later June 16, ANS said in a news release: "A competent, effective and fully staffed U.S. Nuclear Regulatory Commission is essential to the rapid deployment of new reactors and advanced technologies. The arbitrary removal of commissioners without due cause creates regulatory uncertainty that threatens to delay America's nuclear energy expansion."

Speaking that morning, Piercy cautioned about the wholesale slash-and-burn approach implied in Trump's May 23 directive: "We all have to keep an open mind, but we have to get this right. A full reset of regulation at this stage will likely slow things to a crawl. It's time we put away the meat cleaver and pull out the scalpel, because we need NRC on the road to recovery as soon as possible."

The largest U.S. commercial nuclear operator, Constellation Energy, was represented at the conference by Chief Generation Officer Bryan Hanson, who tempered the grandest aspirations for U.S. nuclear with some hard statistics: The United States built about 100 GW of civilian nuclear capacity roughly from 1965 to 1990, then little more than zero since then. Now President Trump wants to reach 400 GW between 2025 and 2050.

"So the challenge is real," he said. "The hearts and minds of all of you in the room today have to embrace and accept that challenge that says what they did from

A rendering of Ontario Power Generation's Darlington project, where a GE Vernova Hitachi BWRX-300 is projected to become the first operational small modular reactor in North America. | *GE Hitachi Nuclear Energy*

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1965 to 1990 was incredibly challenging."

What is not so challenging as it appears, Hanson said, is meeting the coming growth of load demand. "I think the forecasts are incredible at best," he said. And he noted a recent Duke University study showing extensive U.S. grid capacity could be freed up with demand response. (See *U.S. Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

NRC Commissioner Matthew Marzano noted this is not the first "nuclear renaissance" declared in recent memory: Construction of new reactors begun in Georgia (Plant Vogtle) in 2009 and South Carolina (V.C. Summer) in 2013 was heralded as such. But Vogtle took more than a decade and more than $30 billion to complete. The V.C. Summer expansion was abandoned after $9 billion was poured into it.

"I don't like to use the word, but there was the first 'renaissance,' and V.C. Summer was kind of the death knell of that when that project shut down," he said. "But I think that this moment is different. There is a confluence of factors … that really makes a huge difference in terms of the future. And so we're very excited. And of course, this administration has very ambitious goals."

Marzano said the *ADVANCE Act of 2024* is a springboard toward those goals, making the NRC more efficient and effective.

He spoke of a cultural shift under way within the NRC after the ADVANCE Act but called it a series of small steps that add up to a very big change — a different approach from the one Trump laid out in May.

Marzano also asked for input on the process: "We won't be able to see everything. So that's where our licensees, our applicants, our stakeholders are going to be very important in helping NRC identify where its blind spots are."

Much more is on the agenda at the ANS conference as it continues through June 18, including the workforce development and technology evolution the nuclear power industry will need if it is to exploit the growth potential that stands before it now. But that growth set the tone for the introductory discussions.

Kirsten Laurin-Kovitz, associate laboratory director for nuclear technologies and national security at Argonne National Laboratory, said: "Everything is aligning for nuclear energy, something we haven't seen since the 1970s. But this isn't just a comeback story. It is nuclear energy's moment to truly energize the world."

GE Vernova Hitachi Nuclear Energy Chief Commercial Officer Nicole Holmes listed four factors critical to nuclear seizing the moment:

- Companies in the nuclear sector like to be the second to go, but somebody actually has to go first.
- The industry must dramatically improve its delivery model, and the government needs to offer support for early movers to have assurance of completion amid the risks.
- There need to be partnerships, ecosystems and an array of people supporting the vision.
- The United States needs to look beyond its own borders.

The first small modular reactor in North America, for example, is a GE Vernova Hitachi BWRX-300 that Ontario Power Generation will operate near Toronto, and the reactor pressure vessel was made in Italy.

"We need to cast a global vision," Holmes said. "We're not going to do this all in the United States."

One obvious example is the leadership that controls and guides this growth, she said, apparently adding one more yellow flag to those raised by other speakers referring to Trump's changes.

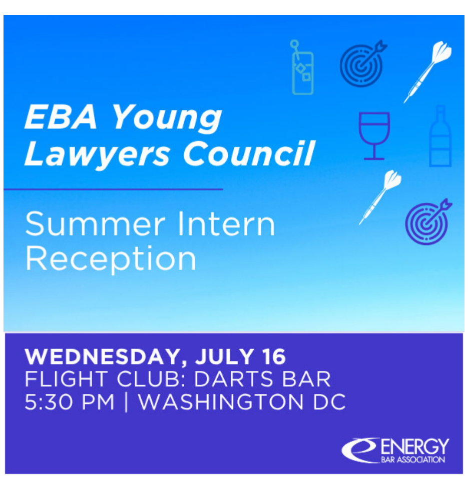
"Really, we need to continue to be in a leadership position on how we think about regulation and training programs," she said. "The world is looking to the U.S. a bit to say, 'How are we doing this?' And I think not doing a wholesale changeover of what's been working, just improving, that would be a smart idea for continued collaboration."

Constellation's Hanson was asked when the nation's largest nuclear operator might expand its fleet with a new build.

After the spinoff from Exelon in 2022, he said, "New nuclear was nowhere on our strategy. I would say it's starting to creep up into the strategy now, because that's what our customers want."

But first, the company will concentrate on existing assets — restart of Unit 1 at the former Three Mile Island and uprates of operating reactors elsewhere. That will add 2 GW of capacity and cost $7 billion to $8 billion.

"So our dance card is pretty full, when you think about it," Hanson said. ■



Senate Finance Committee Looks to Eliminate Energy Tax Credits in 2028

Reconciliation Bill Changes Offer Longer Phaseout Timeline than House Version

By James Downing

Senate Finance Committee Chair Mike Crapo (R-Idaho) released *language* for the massive reconciliation bill that includes major cuts to tax subsidies for clean energy.

A version of the bill already passed the House with deep cuts to energy credits that would cause them to sunset and include restrictions that many in the industry say would render them useless. (See *House Passes Reconciliation Package that Would End Energy Tax Credits*.)

The bill would make the 2017 Trump tax cuts permanent, thus avoiding a "$4 trillion tax hike," Crapo said June 16.

"The legislation also achieves significant savings by slashing Green New Deal spending and targeting waste, fraud and abuse in spending programs while preserving and protecting them for the most vulnerable," he added.

| *Shutterstock*

The language the Finance Committee released yesterday would phase down key tax credits even more quickly than in the proposal the House passed. The House version would let clean energy projects get full tax credits through 2028 before being cut over the next several years and expiring entirely on Jan. 1, 2032.

While the House bill required projects to be completed to receive credits, the Senate version keeps the current language that projects only need to start by a certain date to get them. But it slashes the production tax credit and the investment tax credit to 60% of their current total starting in 2026, then 20% for projects starting in 2027, and finally makes projects that start after Dec. 31, 2027, ineligible for them entirely.

The language would include new prohibitions for the 45U production tax credit for nuclear plants, limiting the use of fuel from some foreign suppliers.

The bill would also cut tax credits for plug-in electric vehicles entirely, as well as other credits aimed at making homes and commercial facilities more energy efficient.

Edison Electric Institute interim CEO Pat Vincent-Collawn said the Senate language offers "more reasonable timelines" for phasing out energy tax credits and preserving their transferability.

"Financial certainty and access to cost-effective financing are critical tools for electric companies as they continue to make needed investments to meet rising customer demand and to expand generation capacity," Vincent-Collawn said in a statement. "These modifications are a step in the right direction, and we thank Chairman Crapo for his leadership in balancing business certainty with fiscal responsibility. We look forward to continuing to work with lawmakers to ensure the final package incorporates practical, pro-growth policies that support our shared goals of strengthening America's energy security and keeping customer bills as low as possible."

Why This Matters

The proposed changes to the reconciliation bill would provide a longer phase-out of energy tax credits than the House version, but still sunset them completely in 2028.

The Union of Concerned Scientists said the Senate language, like the version that already cleared the House, would slow down clean electricity deployment, undermine domestic manufacturing of batteries and electric vehicles, and make EVs more expensive and less available.

"This proposal specifically and repeatedly sidelines the exact clean technology solutions that are ready and able to deliver benefits for people and communities all across this country," UCS Energy Analyst Julie McNamara said in a statement. "These are the solutions that have driven enormous gains to date and are poised to deliver so much more — if only lawmakers would let them."

Steven Nadel, executive director of the American Council for an Energy-Efficient Economy, called on senators to leave the credits for energy efficiency and electric vehicles in place.

"Canceling these credits would increase monthly bills for American families and businesses," Nadel said in a statement. "Why would we stop helping families save energy when prices are going up and up? Americans didn't vote for higher energy bills. At a time when we're concerned about strain on the electric grid, it's particularly absurd to waste more electricity." ■

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CEC Approves Massive Solar-plus-storage Project

Darden Clean Energy Project is 1st Approved Under Agency's Streamlined Process

By Elaine Goodman

California regulators approved Intersect Power's Darden Clean Energy Project, which is expected to be the largest battery energy storage system in the world when completed.

The California Energy Commission voted June 11 to approve the project, which includes a 1.15-GW solar facility and 1.15 GW of four-hour battery storage. The solar facility will consist of about 3.1 million panels.

The decision marks the commission's first project approval under its streamlined "opt-in" permitting process.

"The transition to 100% clean electricity by 2045 requires bold, utility-scale projects like Darden," CEC Chair David Hochschild said in a statement. "This project is significant not only for its size but its cutting-edge design and safety measures."

The CEC *reported* in April that California had 15,763 MW of battery storage: 13,248 MW of utility-scale storage, 1,829 MW of residential storage and 686 MW of commercial storage. The total puts the state at about 30% of its storage target of 52,000 MW by 2045.

"The key to a cleaner, more reliable power grid is batteries – and no other jurisdiction on the planet, save China, comes even close to our rapid deployment," Gov. Gavin Newsom said in a statement last month.

Community Benefits

Intersect Power subsidiary IP Darden I will build the Darden project on 9,500 acres of retired agricultural land in Fresno County. It will interconnect to one of Pacific Gas and Electric's existing 500-kV transmission lines, Los Banos-Midway No. 2.

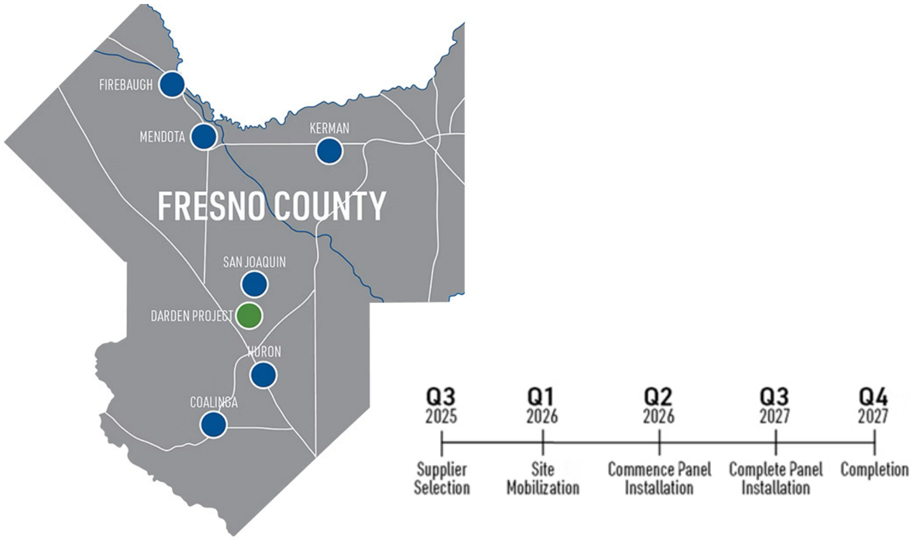
At one point, the Darden project included an 800-MW green hydrogen facility, but that component was scrapped last year. (See *2 Huge Solar-plus-storage Projects Planned in California*.)

Under the CEC's opt-in requirements, projects must deliver community and economic benefits. The Darden project will invest $2 million into the community over the next decade, starting with $320,000 to Centro La Familia Advocacy Services, a nonprofit that supports crime victims, family wellness and civic engagement in rural communities.

In addition, the project will produce more than 2,000 prevailing-wage construction jobs and an estimated $169 million in economic benefits over its 35-year lifetime.

The CEC's opt-in certification is a voluntary process intended to streamline permitting of renewable energy projects.

Under the opt-in procedure, the CEC becomes the lead agency for permitting and state environmental review, consolidating the permitting process. The environmental review for a project must be completed within 270 days of the project application being deemed complete, unless the proposal changes significantly.



| Darden Clean Energy Project

Why This Matters

The CEC's approval of the Darden Clean Energy Project could set the tone for permitting of other large projects needed to meet California's ambitious clean energy goals.

Intersect Power has another solar-plus-storage proposal moving through the opt-in certification process. The Perkins Renewable Energy Project, proposed by subsidiary IP Perkins, would be a 1.15-GW solar facility in Imperial County. It also would include up to 1.15 GW of four-hour battery storage, or up to 4,600 MWh of storage.

Another opt-in project, the Compass Energy Storage Project, was the subject of a public meeting this month. The proposed 250-MW project in Southern California has drawn a slew of comments, many voicing concerns about the safety of the facility. (See *CEC Considers Opposition to Compass Battery Project in Southern California*.)

In a release about the approval of the Darden project, the CEC said the safety of battery storage facilities "remains a top priority."

Last year, the governor launched a state-level collaborative to continue to strengthen safety standards for battery storage systems. The efforts include updating the California fire code to include specific fire safety requirements for stationary lithium-ion battery storage systems.

The California Public Utilities Commission also approved new safety standards and enhanced oversight of emergency plans for grid-scale battery energy storage systems. ■

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Former Seattle City Light CEO Nominated for WEM Governing Body

Nominating Committee also Calls for Reappointment of Andrew Campbell

By Robert Mullin

Former Seattle City Light CEO Debra Smith has been nominated to join the Western Energy Markets (WEM) Governing Body, with a three-year term to begin July 1.

Established in 2016, the WEM Governing Body is the oversight board for CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM), the latter of which is scheduled to launch in 2026 with PacifiCorp and Portland General Electric as its first members.

The Governing Body was last year authorized to begin assuming greater authority over decisions related to the two markets as part of the "Step 1" proposal by the West-Wide Governance Pathways Initiative, a multistate effort to bring more independent governance to the ISO's markets in the face of competition from SPP's Markets+ offering. (See *CAISO, WEM Boards Approve Pathways 'Step 1' Tariff Amendments*.)

"Ms. Smith has demonstrated wide-ranging expertise and experience that will help guide the ISO as it navigates issues relating to market rules of the Western Energy Imbalance Market and Extended Day-Ahead Market, and an increasingly changing energy and electricity market landscape," Northern California Power Agency General Manager Randy Howard, chair of the WEM Nominating Committee, wrote in a June 11 *memo* to Governing Body members, who will vote on Smith's nomination at their June 18 general session in Reno, Nev.

Smith was City Light's CEO for five years before retiring in 2023, "leading the utility through a significant modernization program," according to the memo. Former Seattle Mayor Jenny Durkan appointed Smith to lead the utility after it became mired in a host of organizational problems, including widespread claims of sexual harassment and cost overruns for a new billing system.

Smith began her career in the utility sector in 1996 with the Eugene Water and Electric Board in Oregon, where she rose to the position of assistant general manager. She was then chosen to head up Central Lincoln Public Utility District in Newport, Ore.

Debra Smith was CEO of Seattle City Light for five years. | *Seattle City Light*

Why This Matters

The Western Energy Markets Governing Body will be taking on increasing responsibility for CAISO's markets with the expansion of the Extended Day-Ahead Market.

"Ms. Smith is a respected voice in both regional and national energy affairs," Howard wrote in the memo. "She is well networked throughout the West with a deep understanding of energy markets in the region along with well established relationships and the willingness to engage proactively with current and potential WEM market participants."

Smith would be assuming the seat being vacated by John Prescott, the last remaining member of the original Governing Body appointed in 2016. Prescott is stepping down after reaching the body's limit of serving three full terms.

Campbell up for Reappointment

The WEM Nominating Committee has also recommended the reappointment of Member Andrew Campbell to another three-year term.

Campbell was first appointed to the Governing Body in 2022 and served as its chair from July 1, 2023, to June 30, 2024.

"Member Campbell works diligently to prepare for decisions and to understand ISO staff analysis and stakeholder perspectives on complex market issues that come before the Governing Body," the memo said. "He has worked to maintain existing relationships and to build new relationships with stakeholders across the market footprint."

Campbell is executive director of the University of California, Berkeley's Energy Institute at Haas. ■

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CAISO Proposes Alternative Approach for Calculating RA Resources During Peak Times

Seasonal Derates not Consistently Reflected in RA Data

By David Krause

CAISO is proposing a new method for verifying how much energy thermal resources can provide during peak conditions on California's grid for resource adequacy purposes.

CAISO presented *the proposal* at a June 11 meeting as part of its resource adequacy (RA) working group, which reviews RA rules, requirements and processes for grid reliability and operations.

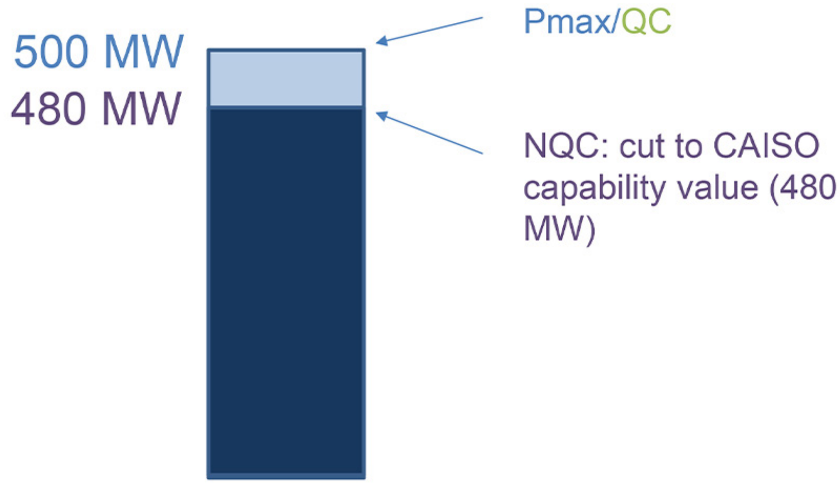
Under current rules, a resource's seasonal ambient derate data is not consistently reflected in that resource's net qualifying capacity (NQC) value. This inconsistency creates challenges in reliably operating the grid, CAISO said in its proposal. For example, a 50,000-MW peak load contains about a 4% ambient derate, compared to a 20,000-MW peak load on the system, which has about a 2% ambient derate, CAISO said.

In California, RA programs began in 2004 under the California Public Utilities Commission to ensure the state's grid always had enough power to meet demand. CAISO's RA initiatives are intended to complement the CPUC's RA programs.

In the proposal, CAISO would verify an RA resource's qualifying capacity (QC) value based on that resource's historic outage data. The proposed method "ensures RA resources' operational capabilities during peak load conditions are reflected in NQC values," CAISO said in the proposal.

Why This Matters

California's resource adequacy programs help the state meet demand at all times of the year, but currently, seasonal ambient derate data is not accounted for consistently in those programs.



This example shows how a thermal plant's RA availability would be calculated. | *CAISO*

More specifically, CAISO would produce monthly "capability values" as part of its NQC process. These capability values represent a resource's availability during peak load conditions, which often happen during times of high ambient temperatures.

To calculate a capability value, CAISO would review a resource's ambient derates due to temperature during peak demand in recent years with existing outage management system data, CAISO said in the proposal. Each year, CAISO publishes RA NQC data to its *reliability requirements webpage*.

However, the proposed method has a "notable drawback," CAISO said. Forced outages are "not consistently reported by resource SCs when a resource is experiencing multiple overlapping outages," CAISO said.

To address this potential issue, scheduling coordinators (SC) could adjust proposed QC values based on site-specific generator performance information under typical peak system conditions, thereby establishing monthly capability values for thermal resources. If weather data is not available at a generator's site, SCs could pull data from nearby weather stations. SCs then could verify that a generator's maximum output is feasible. This maximum value could reveal the generator's likely performance under typical peak system conditions, CAISO said.

The proposed method would apply only to thermal resources — i.e., gas, oil, coal, nuclear, biomass, geothermal and biogas fuel types — and represents resource availability during median peak load conditions, not extreme conditions.

American Clean Power-California, in comments to CAISO, said it is concerned about double counting under the proposed method. The group encouraged CAISO to avoid including historic ambient derates into NQC processes if those historical derates already are accounted for in other processes.

CAISO also considered using performance test data from each thermal generator, rather than historical data, to verify an RA resource's QC value. However, stakeholders viewed the potential benefits of such a testing program as "providing limited value compared to the administrative costs of such a program," CAISO said.

"Given the challenges and administrative burden of developing an NQC testing program in accordance with CAISO [tariffs], CAISO is not moving forward with a testing-based proposal," CAISO said in the proposal.

Stakeholder comments on the proposal are due by June 25. ■

Analysts to Western Regulators: Wildfire Risk is Issue du Jour

Liability Exposure Weighs on Utility Access to Capital, Analysts Say at WCPSC Meeting

By Robert Mullin

From left: Nina Suetake, NASUCA; Julien Dumoulin-Smith, Jeffries; Paul Kjellander, Public Utilities Fortnightly | © *RTO Insider*

PORTLAND, Ore. — Western states must deal with the high risk wildfires pose to the financial health of the region's utility sector, investment analysts told regulators at the annual meeting of the Western Conference of Public Service Commissioners.

"That is the inextricable conversation du jour in the West — period. There is no bigger conversation we're going to have," Julien Dumoulin-Smith, managing director at investment banking company Jeffries, said during a June 2 panel to discuss electricity affordability issues.

For Dumoulin-Smith, the issue comes down to one key topic: "We have to talk about wildfire tort reform."

Dumoulin-Smith, an equity analyst who covers the energy sector, focused on how wildfire risk could hamper Western utilities from raising capital to fund infrastructure projects. He said the West is "a fire or two away" from having a "truly unfinanceable outcome" for investing in the grid.

"The impact is actively being felt when you look at the cost of capital across the West," he said. "It's not in the ether; it's actually dollars and cents to utility ratepayers today."

Dumoulin-Smith finds it "striking" that the industry stakeholders seem to think there's an "inevitable amount of money that we have to spend towards wildfires," which is increasing the portion of ratepayer bills dedicated to mitigating wildfire risk.

Why This Matters

Wildfire liability risk increasingly is impeding Western utilities' access to low-cost capital for infrastructure projects.

And despite the thinking of some in the industry, he contended, California's Assembly Bill 1054 — passed in 2019 to establish a fund for utilities to tap to cover wildfire damages claims — has not resolved the risk exposure issue for the state's utilities. (See *California Wildfire Fund Could be Model for US, Panelists Say*.)

Dumoulin-Smith pointed to the Los Angeles fires in January as an example of California's continued vulnerability to catastrophic fires, despite having the most advanced wildfire planning in the West.

"When you look at what happened in L.A., it's not about who was at fault or what have you. It's looking at wildfire mitigation plans in California [and] recognizing the clear ongoing deficits that exist in wildfire mitigation, period. It's about recognizing that, 'Wait, our state doesn't even engage in wildfire mitigation that is as deep and as intense as in California, and that happened despite all the planning they did,'" he said.

Dumoulin-Smith told the regulators in the audience that if they're not taking the risk issue seriously, it will work against their plans for investing in the grid.

"Because it is devastating to the ability to invest and the cost of capital. It's extremely expensive to invest in a wildfire regime that is inhospitable," he said.

He said different states "have vastly different" policies related to wildfire liability, and while seemingly "trivial," they "are actually quite expensive differences."

"So, I think start with that. I mean, who's at the table, and how do we introduce a problem statement in general?" Dumoulin-Smith said.

'All Perspectives'

During a separate panel discussion, Edna Mariñelarena, an assistant vice president at Moody's Ratings, said investors want to understand the level of risk and return on their investments, and wildfire is "one of those high-risk questions" investors are asking on top of others related to utility infrastructure needs. They want to know what Western states are doing to mitigate those risks, she said.

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"So 'coordination' is a word that we all say, but it's one of those things that really needs to be taken very heavily, because it's not just a utility problem, it's an economic problem," Mariñelarena said. "If you don't have a healthy utility, you don't have economic development that's going to continue to feed the economy and jobs and regular people, right?"

Speaking on the panel with Dumoulin-Smith, former Idaho utility commissioner Paul Kjellander, now a senior adviser with Public Utilities Fortnightly, posed the question of how a utility can address any kind of investment "when the cost of capital is ridiculous," or if it must adjust capital expenses "to recover from the liability associated with a wildfire."

That diversion of funds prevents investments in new transmission and distribution, system hardening and resilience.

"Avoiding some of the catastrophic events — and reducing the financial impact of that — now has to go to something completely and totally different, and I'm not putting a single new kilowatt-hour into the system," Kjellander said. "Somehow, we have to change that dynamic, and we need to do it with an idea of affordability at front and center."

Nina Suetake, deputy director of policy at the National Association of State Utility Consumer Advocates, said that while tort reform might address one aspect of the wildfire issue, it could provoke another — namely, hindering the ability of people in wildfire-prone areas to obtain insurance against fires.

"While I understand from a financial perspective you can't continually bankrupt a utility, the second you put liability caps on, you're also going to impact the trust gap, and it's going to widen even further," she said.

Suetake advocated for a "holistic" approach to dealing with wildfire risk, examining it from "all perspectives."

"You sort of have to bring all of those voices to the table and understand all the impacts if you don't want to just exacerbate one of the problems," she said. "In the end, the ratepayers are citizens of your state, so it's all going to affect the same people; either it's coming from tort liability or increased taxes or increased rates." ■

CREPC TC Close to Wrapping Up Cost Allocation Study

By Henrik Nilsson

The Committee on Regional Electric Power Cooperation's (CREPC) Transmission Collaborative (TC) is wrapping up work on a cost allocation study together with Energy Strategies, while another transmission expansion coalition study with the Western Power Pool is behind schedule, staff said during the Western Interstate Energy Board's annual meeting on June 9.

Since the TC's inception last year, the group's primary focus has been working on a cost allocation study with Energy Strategies called the State Exploration of Western Transmission Cost Allocation Frameworks, Robin Arnold, WIEB's director of state, federal and international affairs, said in a brief update.

Energy Strategies is "wrapping up work on that as we speak. We've received a lot of feedback through the TC on that study that's helped inform what the final report will look like," Arnold said.

The TC is also involved in the actionable transmission study under development by the Western Power Pool's WestTEC. (See *WestTEC Tx Study on Track Despite Delays*.)

"This has been ongoing since we began the collaborative and will continue as long as that study is going," Arnold said. "They're a little behind schedule now, but we've been providing feedback as necessary wherever."

The TC focuses on regional transmission issues by creating a space for CREPC members and staff "to collaborate on transmission coordination and development in the West through sharing viewpoints and information from the diversity of Western states and provinces," according to WIEB's website.

TC meetings have mostly been closed to outside stakeholders to give the "group a chance to learn about the issues and ask as many questions as they want to and just really talk amongst themselves on these various transmission issues," Arnold said.

Why This Matters

The CREPC Transmission Collaborative is one of a handful of initiatives intended to spur development of interregional transmission projects in the West.

TC has also received updates from The Western Transmission Consortium (TWTC), a group focused on developing new ways to fund various projects. TWTC has identified a portfolio of projects in the Southwest for initial project curation and is also working on a study in the Pacific Northwest, according to Arnold. ■

A power line crosses Tempe, Ariz. | © RTO Insider

Expanded EDAM Would Reduce Curtailment, Costs, Study Finds

By David Krause

California Energy Commission staff *presented* a study on the size of CAISO's Extended Day-Ahead Market (EDAM), finding more benefits as the market's footprint increases.

The study, completed by The Brattle Group, is an update to one originally published in January, intended to provide a better picture of the benefits of day-ahead markets in California and the West. The original did not include the Western Energy Imbalance Market (WEIM), which is used as the "Status Quo" scenario in the new version.

Including this scenario helps "show the full impact of a West-Wide EDAM footprint, including how it might affect today's WEIM as participants leave to join SPP Markets+," staff said in a *fact sheet* on the subject. The updated study also includes an analysis of lower natural gas prices in EDAM and an analysis of the change in market revenues for California solar resources from EDAM expansion.

The new study comes as utilities decide whether to join EDAM, which will open in 2026 with its first members, PacifiCorp and Portland General Electric. Additional participants plan to join in 2027 and future years.

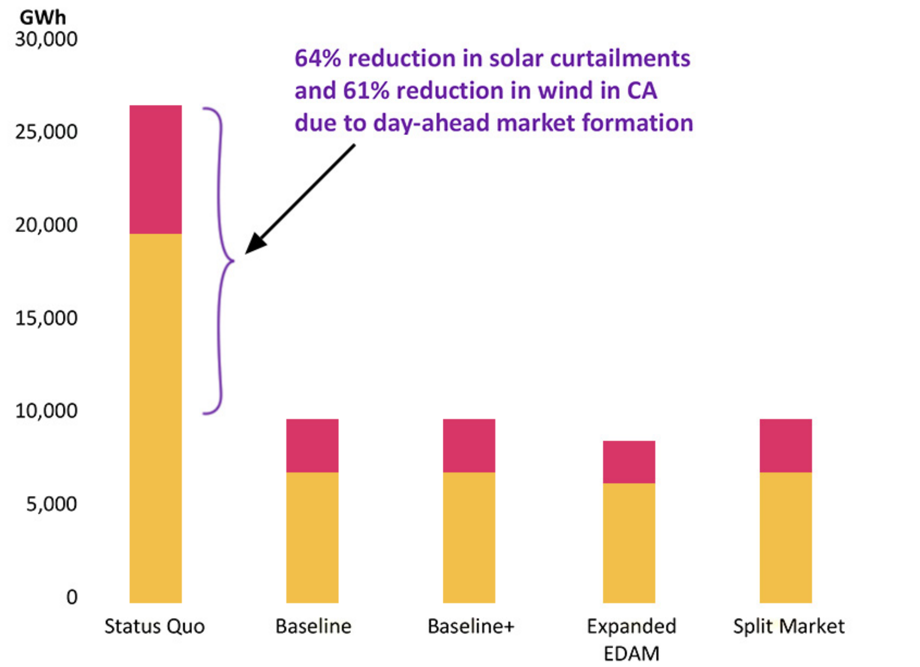
"Generally speaking, day-ahead markets are advantageous because they can deliver cost savings to customers through efficiency gains," Kai Van Horn, senior consultant with Brattle, said at a CEC public workshop June 5. "They can deliver environmental benefits through lower emissions, generally through better utilization of renewables."

Brattle's study looked at four market scenarios alongside the status quo:

- "Baseline," which includes the entities EDAM is expected to launch with in 2026;
- "Baseline+," which also includes likely market participants;
- "Expanded EDAM," which includes the maximum number of entities that could participate; and
- "Split Market," which shows entities operating under both EDAM and Markets+.

Why This Matters

EDAM's size will affect energy customers and developers in California and the West.



Curtailment would decrease as EDAM's footprint enlarges, Brattle found. | *The Brattle Group*

The Expanded EDAM scenario estimates more than $1 billion per year in economic benefits to California compared to the status quo. A larger EDAM could also increase investments in renewables in the area, thereby accelerating emission reductions in WECC, the study says. Greenhouse gas emissions, for example, would decline 58% in California and 39% in the West, respectively, compared to 2024. Revenues for solar increase by about $14/MWh in California in the expanded scenario compared to the status quo.

Annual curtailment would drop from about 26,000 GWh yearly in the status quo to about 8,000 GWh in the Expanded EDAM scenario. Lower curtailments may allow fewer resources to be built to meet renewables targets in the state, the study says.

Even with the initial formation of EDAM, curtailment in California will decrease significantly: a 64% reduction in solar curtailments and 61% reduction in wind, the study found.

In the Split Market scenario, costs and emissions also decrease. For example, emissions drop by 24 MMT/year. In the Expanded EDAM scenario, GHGs drop 25 MMT/year. Similarly for curtailment, the Split Market case shows about 10,000 GWh yearly, compared to 8,000 GWh in the Expanded scenario.

For large solar plants, the market value in California increases from about $-3/MWh in the status quo to $11/MWh in the Expanded EDAM, "largely due to the ability to export otherwise unused solar in midday hours when solar is abundant," according to the fact sheet. The increased market revenues for solar transfer to customers through lower power purchase agreement costs, the study says.

CAISO is currently working on key initiatives related to EDAM as the day-ahead market nears operation. This month, the ISO plans on deciding on a key initiative in EDAM: how congestion revenues are allocated. ■

Calif. Bill Seeks to Control Electric Bills, Create Transmission Authority

SB 254 Would Address Utility Spending on Wildfire Risk, Capital Projects

By Elaine Goodman

A California bill that would take aim at soaring electric bills and create a transmission infrastructure authority has cleared the state Senate and is now being considered in the Assembly.

Senate Bill 254 by Sen. Josh Becker (D) was passed by the Senate 29-10 on June 4. It's now in the Assembly, where it had its first reading. The bill is an "urgency" measure that would take effect immediately upon adoption.

SB 254 is a sweeping bill with nine major provisions, which Becker said would save ratepayers "tens of billions of dollars" over the next several years. He called it "the legislature's most ambitious effort ever to rein in rising energy costs."

"This is not a set of modest tweaks that will make minor improvements at the edges of a problem without offending anyone," Becker said. "This is a big deal."

What's in it?

SB 254 would exclude from electric utilities' equity rate base a collective $5 billion spent on fire risk mitigation capital projects starting Jan. 1, 2025. Similarly, $10 billion collectively spent on energization capital projects would be excluded from rate base.

The bill would create a Power Fund, to be funded by the legislature and used to reimburse utilities for "expenditures driven by public policy goals that provide a benefit to the general public." Those could include transportation or building electrification programs or wildfire mitigation, among others.

The California Energy Commission would decide how money from the Power Fund is spent. Utility spending that's reimbursed from the Power Fund would be excluded from rate base, and infrastructure paid for through the fund would not be eligible for return on equity.

California Sen. Josh Becker (D) presents SB 254 during a Senate floor session June 4. | *California Senate*

Why This Matters

SB 254 proposes the creation of the Clean Energy Infrastructure Authority to help develop major transmission projects in a manner similar to Colorado and New Mexico agencies established to perform the same function.

SB 254 would require utilities to include in their rate case filings a scenario in which spending would not go up more than the projected amount of the Social Security cost of living adjustment (COLA). The CPUC could still approve spending greater than the COLA if it's deemed necessary for safe and reliable operation.

Transmission Authorities

SB 254 proposes the creation of the Clean Energy Infrastructure Authority (CEIA) for transmission projects. The authority would identify transmission corridors; plan, finance, acquire and own transmission lines; serve as lead agency under the California Environmental Quality Act; and exercise eminent domain powers.

The authority would enter into agreements with utilities to build, operate and maintain the transmission infrastructure.

The California CEIA would be similar to two transmission authorities now operating in the West: the New Mexico Renewable Energy Transmission Authority (RETA) and the Colorado Electric Transmission Authority (CETA).

"Establishing transmission authorities continues to be a critical policy lever for states, especially those without [an RTO], to consolidate and formalize transmission planning processes," the National Caucus of Environmental Legislators said in a *policy update* in April.

The group said lawmakers in Washington, Oregon and Montana had introduced bills this year to establish new transmission authorities.

Affordability Issues

SB 254 is part of a three-bill package, intended to address affordability issues in California, that Senate President pro Tempore Mike McGuire worked on with the Democratic caucus. The other two bills address housing production and workforce development.

"Skyrocketing housing costs and utility bills are stretching budgets, and folks are struggling to achieve a job that pays a family-sustaining wage," McGuire said in a statement announcing the bill package in April.

But opinions differed on whether SB 254 is part of the solution.

Sen. Kelly Seyarto (R) pointed to "unrealistic mandates" as the cause of rising electric bills.

"[Utility companies] are going back to the CPUC time and time again," Seyarto said. "Because we are mandating that we attain unrealistic goals for all electric vehicles, for everything being electric in California. And they're trying madly to try and get the infrastructure, which means wires everywhere."

Sen. Steven Choi (R) said creating a new transmission authority would increase costs.

"Who knows how much money this agency will be using to establish and implement the programs and create the policies and employ the employees to run that authority?" Choi said.

Other Provisions

Among other provisions in SB 254, the bill aims to provide near-term relief to electric utility customers by increasing the amount of the "climate credit" they see on their bills each April and October. The credit is part of the state's cap-and-trade program.

Low-income customers would get a greater share of the climate credit under SB 254, and it would be paid out in late summer when many residents are hit with their highest electric bills.

In a permit streamlining measure, the bill would direct CEC to develop a program environmental impact report for energy storage systems of 200 MW or more. Agencies could then build on that more generic EIR when developers propose specific projects, reducing the time needed to prepare an environmental report.

SB 254 would also lower the project-size threshold for a project to be eligible for the CEC's opt-in certification program, from $250 million to $100 million. It would extend the life of the program by five years, through June 2034.

The opt-in program is for renewable energy projects such as solar, onshore wind and energy storage systems. Under the voluntary opt-in process, the CEC becomes the lead agency for permitting and state environmental review. The CEC certificate is in lieu of any permit that normally would be required through the local land-use review process and most state permits. (See *2 Huge Solar-plus-storage Projects Planned in California*.)

SB 254 would also require the CEC to try out permitting management software to further streamline project review. ■

NV Energy Seeks OK for $500M Wildfire Self-insurance Policy

PUCN Approval Would Bring Utility's Liability Coverage to About $1B

By Elaine Goodman

With the risk of catastrophic wildfire growing in Nevada and across the West, NV Energy is seeking approval for a $500 million wildfire liability self-insurance policy.

The $500 million in self-insurance, to be paid for by ratepayers over 10 years, would bring NV Energy's wildfire liability coverage to about $1 billion. The company now has $405 million in commercial coverage and $100 million in existing self-insurance.

The Public Utilities Commission of Nevada (PUCN) has scheduled a hearing on the proposal on June 24.

NV Energy wants the additional self-insurance "in order to have adequate wildfire liability insurance in place in the event that a catastrophic wildfire in Nevada is alleged to be caused or exacerbated by utility equipment," the company said in a filing with the PUCN.

The chance of a wildfire causing $1 billion or more in financial losses in NV Energy territory in the next 10 years is 18% or more, Nathan Pollak, of Scidan Consulting Group, testified as part of NV Energy's application. And the chance of a wildfire causing $2 billion in financial losses in the next decade is 10%, he said.

Pollak recommended NV Energy have $1 billion to $1.5 billion in wildfire liability coverage.

But NV Energy said it is facing rising costs and reduced availability of commercial insurance.

"The products available are expensive and non-traditional – presenting drawbacks that make them less prudent than the self-insurance policy," Mariya Coleman, NV Energy's vice president of corporate insurance and claims, said in the application.

Striking a Balance

NV Energy would create a captive insurance company to administer its self-insurance, just as it did for its existing $100 million self-insurance policy.

The company said the 10-year period to fund the new self-insurance policy strikes a balance between avoiding rate shock to customers while completing the funding in a reasonable amount of time.

About three-quarters of the cost would be paid by customers of Sierra Pacific Power, NV Energy's subsidiary in Northern Nevada, with Nevada Power customers in Southern Nevada picking up the remainder.

If there are any payouts from the self-insurance fund, NV Energy has proposed replenishing it with another customer rate hike.

Shareholders would commit to a 10% co-insurance payment on any claims, up to $50 million. The co-insurance payment wouldn't depend on results of a reasonableness review.

"This co-insurance payment preserves a strong incentive on the part of the companies to mitigate wildfire risk and to settle third-party claims prudently," Michael Behrens, NV Energy's chief financial officer, said in the application.

The co-insurance share is greater than that of the self-insurance policies of two major California utilities, Behrens noted. The shareholder co-insurance payment in Pacific Gas and Electric's self-insurance policy is 5%; for Southern California Edison, it's about 2.5%.

Some stakeholders criticized NV Energy's proposal, saying it is inefficient to have two separate self-insurance policies with different structures, rules and coverage.

Instead, NV Energy should expand and modify its existing self-insurance policy, said utilities consultant Bradley Mullins, who filed testimony on behalf of several gaming interests and other parties.

Mullins said it would be more appropriate for NV Energy to collect the self-insurance funding from ratepayers over 50 years, since a $1 billion wildfire is estimated to be roughly a 1-in-50-year event. And no costs from "imprudence, gross negligence or willful misconduct" should be borne by ratepayers, he said.

Why This Matters

NV Energy's self-insurance plan is intended to avoid the serious financial consequences catastrophic wildfires have had for electric utilities in the West, including significant credit downgrades.

Capital Impacts

In his testimony, Behrens of NV Energy said catastrophic wildfires have had serious financial consequences for electric utilities throughout the West.

In cases where utility equipment was implicated in massive wildfires in California, Hawaii, Oregon and Texas, the respective utilities saw downgrades to their credit ratings, "in many cases to non-investment grade," Behrens said.

"Even a utility that has not been alleged to have caused or exacerbated a catastrophic wildfire faces the risk of a lower credit rating and higher cost of capital if it is not perceived to have sufficiently prepared for the financial risks," he said.

Behrens noted that utilities are a capital-intensive sector that use debt to finance the long-term assets needed to provide service.

The impact of wildfires on utility finances was also a topic of discussion June 2 during the Western Conference of Public Service Commissioners. Investment analysts said wildfire risk could hinder Western utilities' ability to raise capital to fund infrastructure projects. (See *Analysts to Western Regulators: Wildfire Risk is Issue du Jour*.) ■

ERCOT ESRs, Solar Production Lessen AS Costs

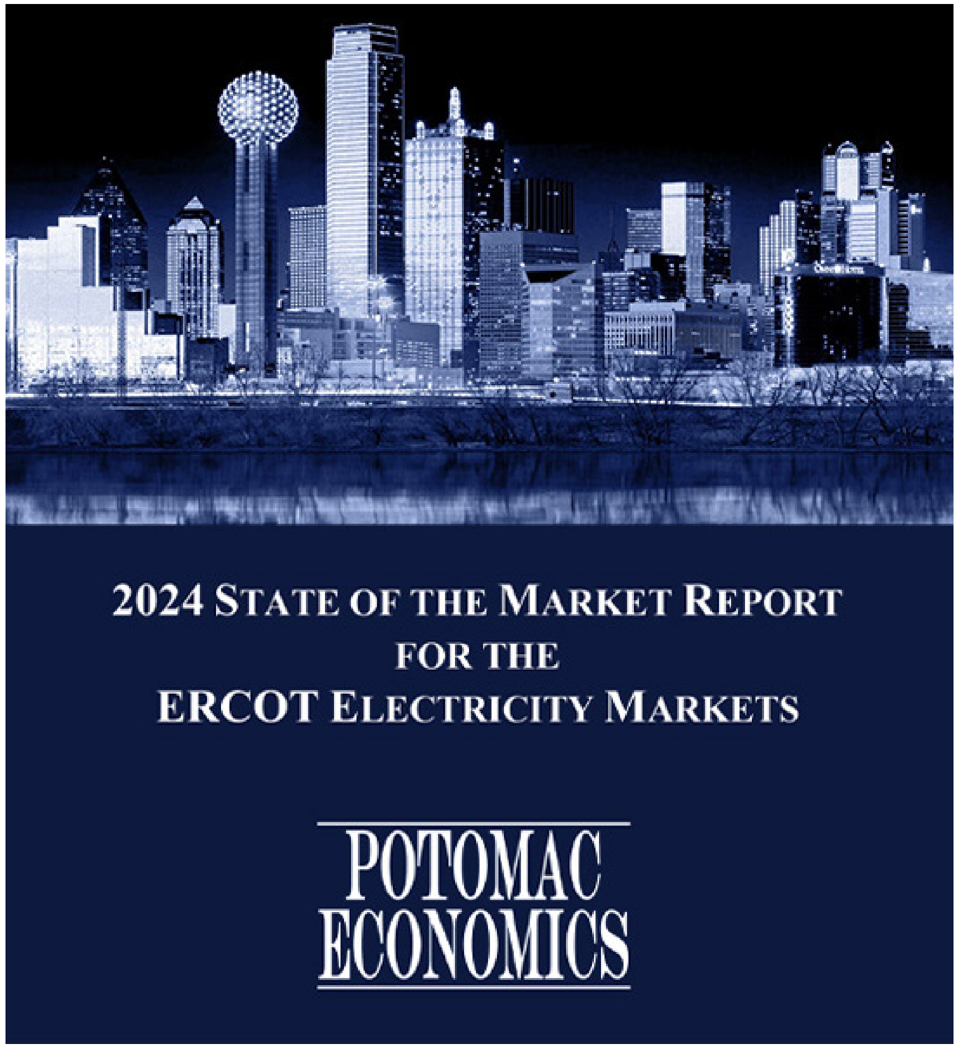
By Tom Kleckner

Energy storage resources and solar capacity helped reduce ancillary services costs and tight system conditions in the ERCOT market in 2024, Potomac Economics said in its recent *State of the Market report* for the ISO.

Potomac, which serves as the grid operator's Independent Market Monitor, said an "influx" of new supply contributed to fewer tight system conditions. Solar and ESRs added 7.5 GW and 5 GW of new capacity, respectively, it said.

The IMM specifically pointed to ESRs as helping produce the supply increase that reduced costs. The IMM said normalized ancillary services expense dropped to $0.98/MWh of load from $3.74/MWh in 2023.

ERCOT contingency reserve service's (ECRS) average price fell to $9.62/MWh from $76.77/MWh but still contributed almost $1 billion in excess real-time market costs. The monitor said the use of ECRS created artificial scarcity conditions by withholding reserves from the real-time market until manually deployed during the seven months after it was implemented in 2023. It said that resulted in an excess cost of more than $12 billion, a claim ERCOT pushed back against. (See *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)



Potomac Economics has released its annual State of the Market report for ERCOT. | *Potomac Economics*

"The continuation of these ECRS deployment practices is a cause for concern," the IMM said. "Most consumers are not directly exposed to these excess costs in the real-time market, but these pricing outcomes factor into future contracts offered by [electric retailers]."

Average real-time prices, excluding adders, fell to $32/MWh, down about 52% despite a 14% decline in natural gas prices. The IMM said more than 75% of the sharp decline was a result of less frequent ECRS artificial shortages.

Day-ahead prices averaged $31/MWh in 2024.

The monitor said real-time co-optimization (RTC), scheduled to go online in December 2025, will improve the issues it raised over market performance and operational risk. A "critical aspect," the IMM said, is that RTC's logic will allow the market to go short on real-time operating reserves, with the shortage's cost defined by set ancillary service demand curves (ASDCs).

The IMM continues to recommend that the grid operator reconsider its policies for procuring and deploying ECRS.

It also recommended:

- That the ASDCs be reformulated based on the marginal reliability value of each product and that ERCOT incorporate a stochastic (using a random probability distribution) risk methodology for setting target levels for operating reserves. The IMM said embedding this tradeoff in the real-time market-clearing logic will address many of the issues it identified with ECRS deployment.
- That policymakers move away from the four-coincident peak (4CP) method — which calculates each consumer's 4CP transmission tariff rate for the following year based on their load ratio share during the previous summer's highest systemwide demand 15-minute intervals — and implement a transmission cost-allocation framework that more accurately reflects cost causation.
- An uncertainty reserve product provided by resources that can start in two hours or less when reliability is threatened.
- A multi-interval, real-time market process that can look ahead and optimize across several intervals.
- That ERCOT prioritizes development of market solutions that ensure resource adequacy, given projected load growth and the development lag between price signals and new generators' commercial operations date. ■

TAC Approves Tabled Curtailable Load NPRR

ERCOT stakeholders have approved a protocol change that registers load as curtailable in certain conditions. | *Shutterstock*

ERCOT stakeholders wasted little time in discussing and unanimously approving a revision request (*NPRR1238*) during a June 12 webinar that it had tabled in May.

Technical Advisory Committee members spent more than two hours debating the measure during the May meeting. During the June 12 call, they spent a little more than 15 minutes considering additional comments and approving the NPRR.

"My over-under was actually more in the 30-minute range, so this is really exceeding my expectations," TAC Vice Chair Martha Henson said in facilitating the webinar.

The revision request and its related change to the Nodal Operating Guide (*NOGRR265*) would register loads that can curtail under certain system conditions so they can be accounted for differently in load-shed tables. The NPRR was tabled until the Texas legislative session ended June 2 in case further revisions had to be made to the measure.

The Texas Industrial Energy Consumers advocacy group *filed comments* June 5, noting that a utility does not have a "unilateral right" to require a customer to commit to being controllable to be interconnected. It said without making the curtailable load voluntary, the NPRR would need to be revised to define what qualifies as "curtailable."

"It can't be mandatory," said attorney John Russ Hubbard, representing TIEC. "It's voluntary to register once you are part of a voluntary, early curtailable load. It is mandatory to comply with ERCOT instructions. We think this squares nicely with [state law], and it also squares with Senate Bill 6."

ERCOT staff and Golden Spread Electric Cooperative, the NPRR's sponsor, also filed comments. They agreed with Hubbard, leading to the 29-0 approval of the measure. ■

— Tom Kleckner

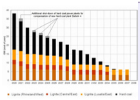
National/Federal news from our other channels

Hail Remains Costliest Risk for Solar Farms — NetZero Insider

NERC State of Reliability Report Highlights Progress and New Challenges — ERO Insider

NERC Standards Committee Reviews Project Prioritization — ERO Insider

NERC RSTC Tackles Priority Projects in Quarterly Meeting — ERO Insider



RF: Germany's Reliability Crisis Holds Lessons for U.S. — ERO Insider

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

Texas RE Adds AI as Risk to ERCOT Region's Reliability

By Tom Kleckner

The Texas Reliability Entity has added key risks related to artificial intelligence and large loads as part of its annual *Reliability Performance and Regional Risk Assessment*.

ERCOT's Regional Entity says AI "introduces some new challenges that we need to be cognizant of."

Texas RE's David Penney, director of reliability services, said during a June 16 webinar that the organization looks at three aspects of AI: as a large load, operating patterns and cybersecurity.

"When you look at the load patterns the AI-type data centers put on the grid, it's not the typical pattern that you can see from a normal data center," he said during the "Talk with Texas RE" session. "Most normal data centers have a fairly flat, stable load protocol. [With] AI-type data centers, it's more of a sawtooth pattern with very steep ramps, up and down ramps over short periods."

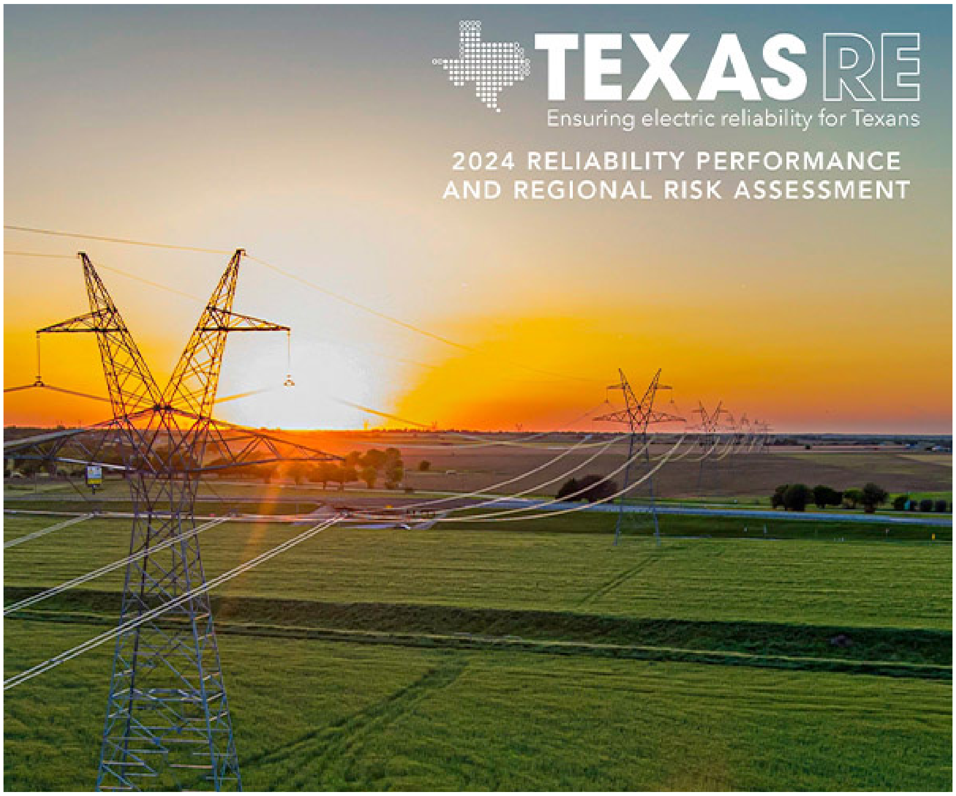
Penney said AI data centers' ramps will stress the grid's voltage support in local areas. And then there's the cybersecurity risk brought by their operations.

"AI brings significant opportunities for the electric grid to be able to modernize and make quicker decisions," he said. "When we incorporate this, there's also a huge cybersecurity risk along with it. Machine-learning type models can possibly be compromised by an adversary."

Texas RE assesses AI integration risks as having a moderate impact on the ERCOT region. "As AI increases in scale and integration, however, associated risks may increase in both likelihood and impact," it said, promising to monitor AI developments.

The entity assessed the "disorganized integration" of large loads as a likely risk — and the largest — with major impacts, an escalation from its 2024 report. It said the load integration's pace and scope and forecasts of negative reserve margins beginning as soon as 2026 are expected to have a major effect on bulk power system reliability.

ERCOT's large-load interconnection queue gained more than 25 GW of capacity in March. The queue contains more than 136 GW of study requests, with a little more than 4.5 GW energized since 2022.



The Texas RE has released its annual Reliability Risk Performance and Regional Risk Assessment. | *Texas RE*

Why This Matters

The Texas Reliability Entity says the "disorganized" integration of AI and other data centers is the biggest risk facing the ERCOT region. The addition of AI is new, but the integration of large loads was added as a risk in 2024.

"While a number of these resources will likely not materialize, the rapid increase in load on the system presents significant forward-looking challenges. These load increases reflected in future reserve estimates have been striking," the report says.

The Texas Legislature has *passed a law* that directs the state's Public Utility Commission to create a framework for adding data centers and bitcoin miners without stressing the grid or saddling other consumers with an unfair share of infrastructure costs. Gov. Greg Abbott (R) has yet to sign the legislation.

The Texas RE says the generation necessary to meet the increasing demand continues to "evolve toward" variable resources and energy storage. Solar generation has increased exponentially and, along with wind, produced 34.8% of total energy in 2024, the report said.

Storage capacity neared 10 GW in 2024 and is forecast to almost triple to 27.5 GW over the next two years. That places "increasing dependence" on inverter-based resources, the RE said.

Penney said the ERCOT region had one hour in 2023 where renewable penetration was over 70%. That increased to 39 hours in 2024 and already has exceeded 100 hours in 2025.

Still, the report said the region's reliability performance "remains strong while navigating these challenges."

The assessment comes on the heels of NERC's annual State of Reliability *report*, which was released June 12. (See *NERC State of Reliability Report Highlights Progress and New Challenges*.) ■

IESO Seeks to Shore up Capacity Market

By Michael Brooks

The IESO Technical Panel approved for posting rule changes to reduce unfulfilled capacity commitments by making it easier for participants to transfer their obligations and harder to buy them out.

The panel on June 10 approved posting the revisions for comment by voice vote with no objections or abstentions.

IESO conducts a capacity auction once a year, and suppliers can bid on obligations for either of two periods — summer (defined as May 1 to Oct. 31) or winter (Nov. 1 to April 30) — or for both. Auctions are conducted in late November for the capacity periods beginning the next year. This year's auction will be held Nov. 26-27 for the periods beginning May 1 and Nov. 1, 2026, with results posted Dec. 4.

Resources are expected to participate in the energy market during the periods for which they purchased obligations through the auction, or they can buy out or transfer their obligations. Buyouts are subject to a charge equal to 30% of the total obligation value.

According to IESO, the market saw its "highest level of competition ever" in 2024, with 2,122.2 MW secured for summer and 1,524.6 MW for winter at $332.39/MW-day and $139/MW-day, respectively. It said it secured 15% more capacity than in 2023's auction, at lower prices.

But Adam Cumming, IESO market rules adviser, told the Technical Panel that every year "a small number of resources" — representing about 100 MW, according to the ISO — are unable to fulfill their obligations "for a variety of reasons." Among these is simply not completing the necessary registration requirements during the forward period (after the auction but before the obligation period) by the posted deadlines.

Unfulfilled obligations reduce "the capacity available to the IESO and distorts auction clearing price signals," the ISO said in a *presentation* in May.

Among the changes the panel approved for posting is an increase in the buyout charge to 50%, intended to deter participants from taking on commitments they cannot meet and incentivize those with obligations to fulfill them. "Hopefully with the increased costs, people will be a little bit more careful in choosing their obligation size," Cumming said.

Suppliers who fail to complete the registration process would no longer have the option of simply forfeiting their deposits and would be required to buy out their obligations. "This change will ensure that all instances of unfulfilled commitments are subject to the buyout charge process," the ISO said.

Why This Matters

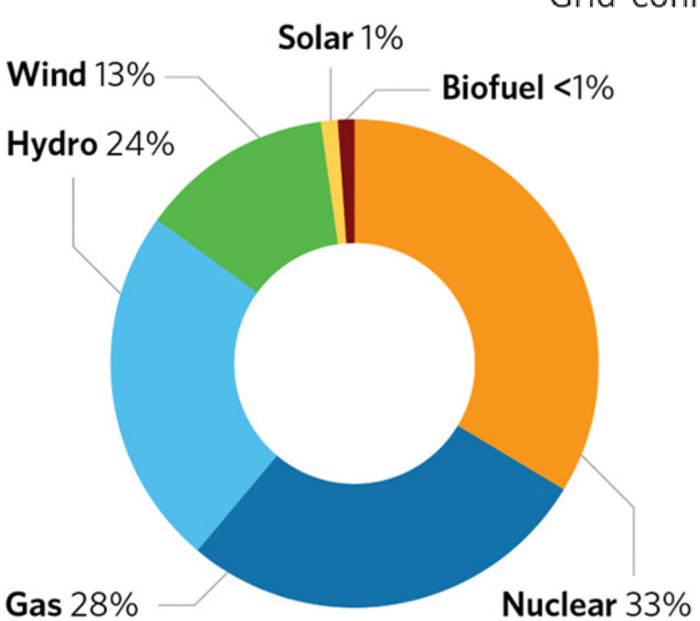
Despite the apparent success of its capacity market and the low amount of unfulfilled obligations, IESO wants to ensure it is as efficient as possible in the face of rising demand.

The revisions would also remove the requirement that obligations can only be transferred between resources with the same attributes.

IESO told the panel that stakeholders are supportive of the changes after working on them for over a year; in the case of the buyout charge increase, the figure was proposed by capacity market participants themselves, it said.

The revisions will be open for comment until June 24. The panel will vote July 15 on recommending them to the Board of Directors for approval at its meeting in August. ■

Grid-connected capacity in 2024 totalled 37,205 MW.



Nuclear	12,184 MW or 33%
Gas/Oil	10,450 MW or 28%
Hydro	8,862 MW or 24%
Wind	4,943 MW or 13%
Solar	478 MW or 1%
Biofuel	287 MW or <1%

IESO capacity makeup in 2024 | *IESO*

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ISO-NE Internal Market Monitor Weighs in on Capacity Market Changes

By Jon Lamson

Why This Matters

The retirement changes likely will be a key component of the capacity auction reform project as the region faces potential retirements of aging fossil units in the coming decade.

The Internal Market Monitor weighed in on ISO-NE's proposed capacity market overhaul at the NEPOOL Markets Committee meeting June 11, expressing support for increased flexibility around resource retirement notifications and recommending the elimination of the pivotal supplier test.

The RTO is in a multiyear effort to drastically cut the time between capacity auctions and commitment periods, improve its capacity accreditation methodology and split each capacity commitment period into winter and summer seasons. It's working with stakeholders on the detailed design of the "prompt" auction, which includes significant changes relating to resource retirements and market power mitigation.

Historically, ISO-NE has processed resource retirements through the forward capacity market, requiring retirement notifications about four years prior to the capacity commitment period (CCP). In the transition to a prompt auction, ISO-NE plans to decouple the retirement process from the capacity auction. (See *ISO-NE Introduces Proposed Resource Retirement Changes*.)

ISO-NE has proposed to require retirement notices two years prior to the applicable CCP. It has said this timeline would balance the need to give participants up-to-date market information with the need to provide ISO-NE enough time to pursue solutions to potential reliability issues created by retirements.

The proposal has evolved in recent months, as ISO-NE initially proposed, and then walked back, a market power penalty intended to deter participants from retiring economic resources in an attempt to increase revenues for their remaining resources. (See *ISO-NE Discusses Details of New Prompt Capacity Market*.)

At the MC meeting, David Naughton, executive director of market monitoring at ISO-NE, expressed *support* for the two-year notification timeline, saying it "reasonably balances reliability and efficient market goals."

Differing from ISO-NE's current proposal, and echoing requests from multiple stakeholders at the prior MC meeting, Naughton recommended allowing resources to rescind deactivation notices "should the economic outlook for the resource materially improve."

ISO-NE has expressed concern that allowing revocable retirement notifications could allow participants to "fish" for out-of-market retentions and could undermine the market signal sent by retirements.

"Low barriers to exit and re-entry in market design are particularly important in the context of uncertainty in demand growth, new entry timing and barriers to entry," Naughton said. The IMM detailed this recommendation in its 2024 annual markets *report*, which encouraged "flexibility around the exit and potential re-entry of existing resources."

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

The report, released in May, noted that capacity prices in the region are "much lower" than the net cost of new entry, with low prices threatening to increase retirements of aging resources in the near-term.

"Depending on the pace and cost of new resource development, it may prove more cost-effective for the market to procure existing resources that can be reactivated, rather than relying solely on new entry," the IMM wrote in the report.

Naughton advocated for a defined "revocation window" for retirement submissions and a clear process for determining whether changes in market conditions warrant rescinding the retirement request. He also recommended that ISO-NE eliminate the capital investment threshold for resource repowering, which would make it easier for retired resources to reenter the market.

Market Power Mitigation

Regarding the mitigation of market power in resource retirements, Naughton said the IMM evaluated three potential approaches: implementing a market power charge, continuing the current framework of proxy supply offers and relying on referral to the FERC Office of Enforcement.

He said the IMM prefers the market power charge approach, but said extending the status quo to the prompt auction format would be "adequate to safeguard

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consumers."

The market power charge approach, Naughton said, provides the "strongest deterrent to exercising market power" and would be more likely to deliver "efficient price formation for current and future auctions."

Continuing the practice of using proxy supply offers for resources that fail IMM conduct and benefits tests would protect customers from high prices in the year following an uneconomic exit but may not prevent impacts beyond that year, Naughton said.

At the May MC meeting, ISO-NE said it remains interested in a market power charge in the long term but said it does not plan to pursue the mechanism in the first phase of its capacity auction reform project, citing concerns about unintended effects expressed by multiple sectors.

To prevent market participants from exercising seller-side market power, the IMM has recommended that ISO-NE replace the existing pivotal supplier test with a "conduct and impact test framework."

Under the current rules, if a participant fails a pivotal supplier test and a conduct test, it is held to a binding price set by the IMM. The IMM wrote in its annual report that a conduct and impact framework would more accurately evaluate and more consistently mitigate market power.

"While the market is currently long on capacity and the ability to unilaterally exercise market power is low, adopting an impact test is robust under all supply/demand conditions," the IMM wrote, adding that as the balance of supply and demand tightens, reliance on a pivotal supplier test "could result in the over mitigation of resources."

Winter Markets Report

Also at the MC meeting, the IMM reported that wholesale market costs more than doubled in the past winter compared to the prior winter, increasing by about $2.4 billion. A mild winter in 2023/24, followed by the coldest average temperatures in decade in 2024/25, was the root cause of this dramatic price swing, said Dónal O'Sullivan of the IMM.

Consistently cold weather caused high gas demand, which drove up energy market costs and increased reliance on oil generation and imports compared to the previous winter, O'Sullivan said. The markets performed well throughout the season and the region did not experience any scarcity conditions, in part due to the lack of extended stretches of extreme cold weather, he added.

O'Sullivan noted that ISO-NE's inventoried energy program (IEP), which compensated generators for maintaining stored firm fuel on-site over the past two winters, did not have a measurable effect on the region's fuel storage levels. The program expired this year, and ISO-NE appears unlikely to revive it in the upcoming years. The program cost about $78 million for the past winter, similar to the cost in the previous winter.

"The equivalent of 4,900 MW per hour of natural-gas-backed generation participated, although it is unclear whether these resources procured additional fuel as a result of their participation," O'Sullivan said. "Oil replenishment was 50% lower than the year prior to IEP implementation, despite similar oil generation." ■

New Pipelines Unlikely for New England, Experts Say

By Jon Lamson

BOSTON — Despite interest from the Trump administration, new gas pipelines into New England remain unlikely due to a lack of counterparties willing to pay for the new lines, energy industry experts said at a recent roundtable discussion.

The pipeline financing uncertainty is driven by the New England states' push for heating electrification, the lack of incentives for gas generators to procure firm capacity, and a *2016 ruling* by the Massachusetts Supreme Judicial Court that electric customers cannot cover the costs of a new pipeline.

"The biggest reason I am skeptical of a new pipeline is: Who is the counterparty?" Dan Dolan, president of the New England Power Generators Association (NEPGA), told attendees of Raab Associates' New England Electricity Restructuring Roundtable on June 13. "Unless Enbridge or Williams or Kinder Morgan are willing to build on spec and are willing to take merchant risk … I don't see it."

Cheryl LaFleur, chair of the ISO-NE board of directors, highlighted financing challenges and a lack of interest from the states as the key obstacles to the development of new pipelines.

"A pipeline is definitely the most efficient way to move gas from point A to point B — that has always been true," LaFleur said. "It is up to the states how much gas they think the region will need and if they want a pipeline. It is not up to ISO New England."

In May, the Trump administration reportedly reached a deal with New York to lift a stop-work order on the Empire Wind project in exchange for concessions from Gov. Kathy Hochul (D) on the Constitution Pipeline project, which was halted after failing to receive permits from the state in 2018. (See *BOEM Lifts Stop-work Order on Empire Wind*.)

Several speakers agreed that, if New England was offered a similar, hypothetical deal lifting regulatory barriers for offshore wind and gas pipeline projects, lawmakers should take the trade.

Rachel Fox, director of policy and strategy at the American Petroleum Institute, speculated that, while offshore wind "is by no means favored by this administration," the Trump administration may allow projects to move forward "if it's part of a deal for a natural gas pipeline."

Liz Stanton, executive director of the Applied Economics Clinic, warned about the health effects of gas generation on local communities, but said the New England states should take the deal because efforts to bring a pipeline to New England appear unlikely to succeed.

Dolan of NEPGA was skeptical the Trump administration would seek this type of deal with the region, noting that the under-construction Vineyard Wind and Revolution Wind projects are well under way and have not been specifically targeted by the Trump administration. He said a deal likely would need to clear obstacles to incremental offshore wind generation beyond these projects, which the administration may be reluctant to do.

Retail Gas Demand

On the gas distribution side, speakers discussed an apparent rift that has emerged in Massachusetts between lawmakers and utilities over the interpretation of language in a major 2024 clean energy bill passed in the state. (See *Mass. Clean Energy Permitting, Gas Reform Bill Back on Track*.)

According to Sen. Michael Barrett, one of the lead negotiators on the bill, the bill authorized gas utilities to disconnect customers from the gas system if viable heating alternatives are available. This change was intended to amend the utilities' "obligation to serve," preventing a single gas customer from holding up the decommissioning of an entire section of gas pipe.

"Last year, we amended Section 92 of Chapter 164, which is the sole basis for the so-called obligation to serve in Massachusetts, and we amended it with the legislative intent of giving our state DPU flexibility … to resolve the so-called holdout problem," Barrett said.

But despite the legislative changes, gas companies continue to argue they are not authorized to deny gas services to existing customers, and that the change in state law applies only to new customers.

"There's a disagreement, I think, in terms of what authority the utilities have to substitute electric for gas, or for the DPU to authorize that substitution," said Jamie Van Nostrand, chair of the Massachusetts Department of Public Utilities.

> **Why This Matters**
>
> While new gas infrastructure could help ease the region's gas constraint, there are major questions about how to pay for the infrastructure, or whether it would provide long-term savings in the context of the region's push to reduce gas dependency.

He said the issue of holdout customers has come up in a National Grid electrification demonstration project, which aims to "decommission one or more leak-prone gas pipe segments through coordinated whole-home electrification of customers."

The company, Van Nostrand said, has taken "is taking the position that decommissioning a segment will require 100% participation of the customers on that segment," creating numerous potential points of failure for the efforts to decommission each segment of pipe.

As the state looks to move the bulk of its residential gas customers to electric heating, it would be "very hard to achieve a gas transition without addressing this issue," Van Nostrand said.

Looking forward, Van Nostrand said the DPU plans to look at the issue more closely "and give the parties an opportunity to brief on that, because it is a real critical issue as we look at the success of these electrification projects."

Caroline Hon, vice president of New England regulation and pricing for National Grid, did not directly answer a question from Sen. Barrett about why National Grid continues to take the stance the utilities do not have the authority to disconnect customers when viable alternatives exist.

Hon framed customer conversions as an equity issue and said that "if we aren't thinking about this thoughtfully, it can be very regressive, and the most vulnerable people, the customers who can't actually to convert, are going to be the ones who really suffer." ■

MISO 2025 Transmission Planning Cycle Rises to $13B

By Amanda Durish Cook

MINNEAPOLIS — MISO's 2025 Transmission Expansion Plan (MTEP 25) has amassed an additional $2 billion in investment since early spring, bringing its total to $13 billion.

MISO said the $13.1 billion, 444-project portfolio still is driven mainly by growing load. In spring, the RTO pinned the collection at 434 projects and $11 billion. (See *Load Growth Drives Early MTEP 25 to $11B*.) MTEP 25 is considered preliminary until late fall; MISO revealed the latest MTEP 25 tallies at a June 10 System Planning Committee meeting of the MISO Board of Directors.

This year's MTEP is loaded with a record-high 37 expedited project requests valued at $4.36 billion.

Executive Director of Transmission Planning Laura Rauch said six of MTEP 25's top 10 most expensive projects originated from expedited project requests. MISO's top 10 projects account for 43% of MTEP 25 spending.

The grid operator said 76% of MTEP 25 projects are due to be in service within three years. MISO said MTEP 25's project totals contain more than 1,900 miles in transmission lines.

Rauch said the traditional and expedited projects are set to serve about 8.7 GW in new load across the footprint.

During a June 2 East Subregional Planning meeting, MISO's Scott Goodwin said requests for MISO to expedite MTEP processing of some transmission projects have "exponentially exploded" since 2022, when the RTO fielded only 16.

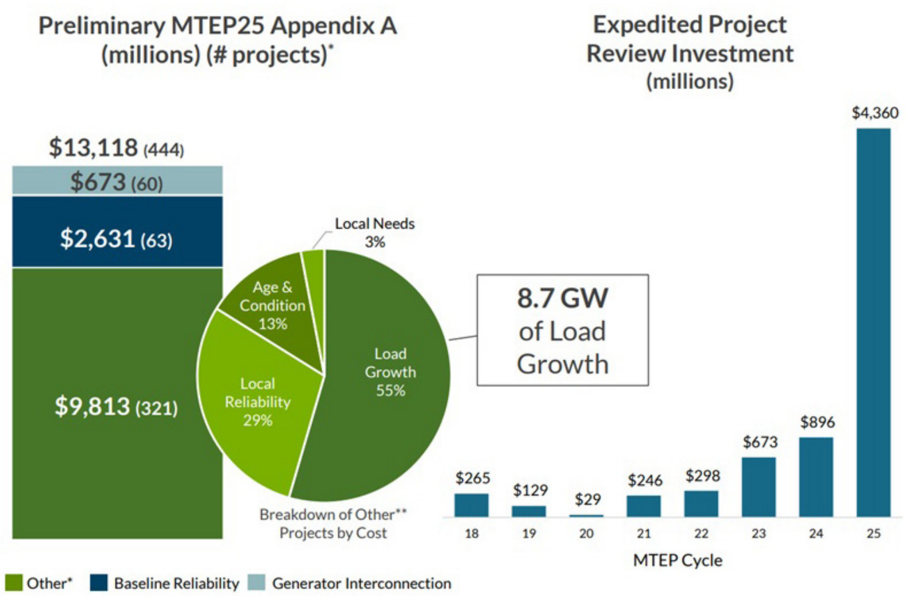
MISO hopes to pivot to a bimonthly processing approach for the growing number of transmission projects submitted by members for expedited treatment.

Going forward, MISO plans to open an every-other-month acceptance window for expedited project requests. It has said the new cadence should be less cumbersome on staff than MISO's existing ad-hoc approach.

Currently, MISO evaluates requests as they're received for transmission projects that cannot wait until end-of-the-year approval through the annual MTEP. MISO originally hoped to roll out a quarterly expedited process but was met with stakeholder resistance. (See *MISO Starting from Scratch on New Schedule for Reviewing Expedited Tx Projects*.)

Why This Matters

MTEP 25 now clocks in at $13 billion and contains a record-breaking number of expedited project requests as transmission developers hustle to make room for load growth.



A breakdown of MTEP 25 projects alongside a chart depicting the rise in expedited project requests since 2018 | *MISO*

MISO plans to study smaller expedited projects in batches while larger, complicated projects will get individual assessments. It said it hoped to debut a 30-day study turnaround for the more straightforward projects.

The grid operator also said it will schedule a single, monthly Technical Study Task Force meeting to discuss expedited projects instead of holding piecemeal, short task force meetings every time a request pops up.

Some stakeholders have asked MISO to consider a load interconnection queue like its generator interconnection queue because of the snowballing expedited requests.

MISO has experienced a runaway volume of expedited requests in recent years as load growth surges. While it used to process an average of six expedited requests annually, since 2021, it has experienced upward of 30 requests. The projects themselves are becoming larger and more complex.

MTEP 25's expedited investment eclipses MTEP 24's $896 million worth of expedited requests and MTEP 23's $684 million.

MISO is set to hold a round of subregional planning meetings to review a more finalized MTEP 25 in September. MTEP 25 goes before the MISO Board of Directors for approval in early December. ■

MISO Reapplies for Generator Interconnection Fast Lane with FERC

By Amanda Durish Cook

MINNEAPOLIS — MISO has put a second proposal for a fast-tracked interconnection queue lane in front of FERC, a mere three weeks after the commission rejected the RTO's initial proposal.

This time, MISO said it will hold to a 68-project limit before retiring the express lane and require regulators to verify in writing that a proposed project will either address a resource adequacy risk or accommodate previously unaddressed load growth in the footprint (*ER25-2454*).

FERC rejected MISO's first try to establish the fast track; the commission said MISO failed to limit the number of projects that could apply and failed to predicate expedited treatment on resource adequacy needs. (See *MISO Going for 2nd Attempt to Fast Track Power Plants in Queue* and *FERC Rejects MISO's Interconnection Queue Fast Lane*.)

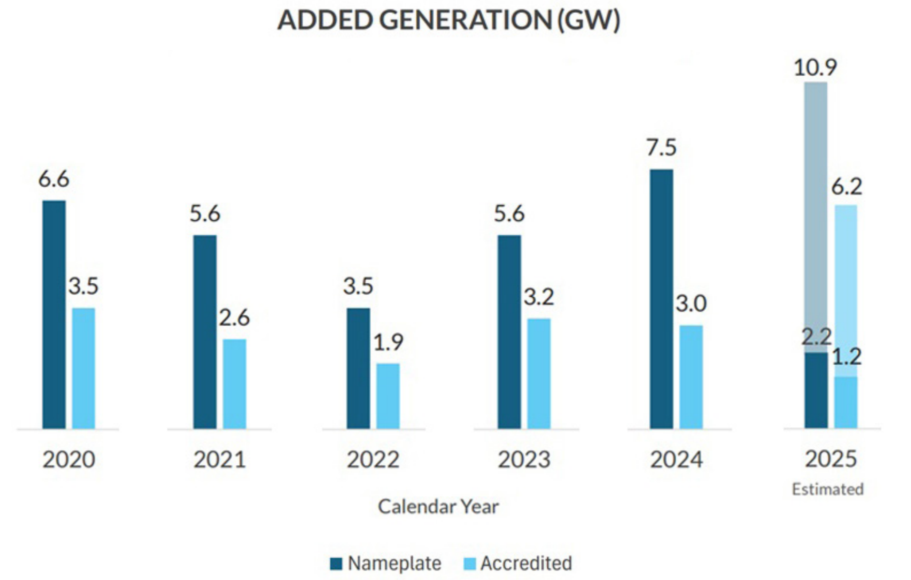
During a June 10 System Planning Committee of the MISO Board of Directors, MISO's Aubrey Johnson said RTO staff knew when drafting the first proposal that changing how certain megawatts "flow" through the queue was going to be an uphill battle.

Johnson said this time around, MISO made the proposal less open-ended by introducing the 68-count limit on projects that get expedited treatment.

MISO committed to processing 10 fast-track applications per quarter for five quarters. Additionally, it added placeholders for 10 projects from independent power producers who have power purchase agreements with non-utility entities and an additional eight projects that can be submitted only by retail states for resource adequacy deficiencies.

Why This Matters

MISO proposed a 68-project limit for its interconnection fast lane, with special reservations for retail choice states and independent power producers. The RTO hopes the project ceiling will make the refiled proposal more attractive to FERC.



MISO is poised to complete a record-setting number of interconnection agreements in 2025. | *MISO*

Johnson said MISO edited language to make it clearer that Illinois' retail choice setup and Michigan's partial retail choice construct are welcome.

The fresh filing also stipulates that projects must reach commercial operation within three years of developers filing an application.

MISO said it will shelve use of the express lane either by Aug. 31, 2027, or when it satisfies the 68-project limit, whichever comes first.

Johnson said MISO is aware that it moved fast to refile the proposal within three weeks of MISO's original rejection.

"When we think about the changes we made … we feel they're appropriate because they're narrow," Johnson said. He said MISO spent several months refining its original proposal, and the limited revisions and cap keep the original intent of the express lane intact.

MISO Director Barbara Krumsiek said she noticed that there was still no "grading" of projects by their resource adequacy contributions.

Johnson said the states, not MISO, decide what's appropriate to maintain resource adequacy.

Sustainable FERC Project's Natalie McIntire complained that MISO's rapid refile cut short stakeholder review and discussion of the revisions. She reminded board members that FERC expects MISO to allow its stakeholders meaningful input on proposed rule changes before the RTO submits them for approval.

As MISO reattempts an interconnection express lane, it's poised to have a banner year for new generator interconnections.

Johnson said MISO estimates that over 2025, it can usher a record-breaking 10.9 GW in nameplate capacity through its queue that would boil down to 6.2 GW in accredited capacity. So far this year, MISO has processed 2.2 GW worth 1.2 GW after applying accreditation.

MISO's traditional queue contains 294 GW across 1,568 projects.

Johnson added that MISO still has 56 GW in generation projects that are cleared to interconnect to the system but remain unfinished. Just five companies are responsible for 40% of those incomplete projects, Johnson said. ■

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FERC Gives MISO 3 More Years on Ambient-Adjusted Ratings

By Amanda Durish Cook

FERC has decided it's practical for MISO to have an almost three-year extension of the commission's directive to implement ambient-adjusted transmission line ratings (*ER22-2363-002*).

With FERC's June 6 decision, MISO has until December 2028 to fulfill its responsibilities under Order 881. Without the postponement, the RTO would have had until July to prepare its systems to accept more varied line ratings from transmission owners.

MISO cited vendors' delays supplying software for the range of line ratings required under Order 881. (See *MISO to Seek 3-Year Order 881 Delay for Vendor Holdups*.)

The commission said MISO "demonstrated that delays in the delivery of vendor software are beyond its control." FERC said the extra three years are key to ensuring continuing reliable market operations.

"We are persuaded by MISO's argument that requiring MISO to implement interim processes could further postpone MISO's overall compliance efforts," FERC wrote.

The commission accepted MISO's explanation that its ability to test the capability hinges on having Limit Exchange Portal (LEP) upgrades in place, which has the RTO and its TOs drawing on the same limited collection of software vendors. MISO also said it needed its new market clearing engine in place before it could use the more technologically advanced LEP.

The commission overruled the Organization of MISO States' suggestion that the RTO could introduce AARs as much as possible in stages. It agreed with MISO that that would "ignore the interlinked nature of the software development MISO requires." FERC said ordering staggered compliance could cause further delay.

FERC took MISO up on its offer to make annual informational filings that describe its progress on the LEP.

During MISO's quarterly board meetings in March, ITC Holdings' Brian Drumm said TOs have met regularly with the RTO on Order 881 compliance since the rule was issued. He said the TOs take seriously their duty to implement AARs, which he called no small task.

"It's an overlay of an entire network and information flowing back and forth," Drumm said. TOs are "all trying to capture the attention of a very select pool of vendors." ■

| *Shutterstock*

MISO Says Public Communication Needs Work After NOLA Load Shed

Stakeholders Keep Pressure on MISO for South Transmission Plan

By Amanda Durish Cook

MINNEAPOLIS — MISO conceded to its Board of Directors that it should have done more to convey the danger it perceived ahead of the late spring load-shedding event in Greater New Orleans.

The RTO reviewed two separate load-shedding events it was forced to take over the spring as part of its quarterly presentation during Board Week: the much discussed 600-MW event in southeast Louisiana on May 25, and the smaller, 27-MW offload it ordered at the MISO-SPP seam in Texarkana as SPP ordered load offline in the Shreveport. La., area April 2. (See *SPP Addresses 3rd Load Shed Since March 31*; *NOLA City Council Puts Entergy, MISO in Hot Seat over Outages*; and *MISO: New Orleans Area Outages Owed to Scant Gen, Congestion, Heat*.)

MISO Executive Director of Market Operations JT Smith said the April and May events were remarkably similar: The load shedding that was required in both cases avoided the potential for voltage collapse, and both events were brought on in part by tornado-ravaged transmission lines and scheduled maintenance being performed on generation in import-constrained areas.

"The spring was incredibly active. It was not one of the easiest springs I've seen overall," Smith told the board's Markets Committee on June 10. "These were not actions that were taken lightly." He added that he understood the ensuing frustrations.

Smith said MISO has had time to reflect since the New Orleans outages and has concluded its channels of communication are lacking.

"It surprised everyone, and it should not have. We should have been more out with our membership … and let them know we were in this tight condition," Smith said. MISO could have warned membership of its grid weakness and told members to ready long-lead load-modifying resources or notified utilities and regulators that public appeals would become necessary, he said.

JT Smith (left) and Zak Joundi, MISO | © RTO Insider

Why This Matters

After introspection on the New Orleans blackouts, MISO said it will likely work on providing more advance warning to members and regulators when it encounters touch-and-go operating days.

"That was a failure on our part for not having that communication out there," he said. "This is one where we probably had more insight than we shared externally, and we need to be better on that."

However, Smith also said MISO only had a few moments before it became clear shedding load was necessary.

Speaking to the board June 12, MISO CEO John Bear said the RTO had a "challenging" spring. He said the 13 generation outages, six derates and a key 500-kV line outage on May 25 had everyone tense.

Bear said MISO is thinking through declarations and posting of transmission contingencies. He said that while it is good at communicating meager energy, it's "not so good" at conveying transmission challenges.

A post-mortem analysis is ongoing, and MISO will discuss the event again and strategies to prevent it at the September board meeting in Detroit, Bear said.

Independent Market Monitor Carrie Milton said the load-shed event was "set in motion" much earlier in the spring when Entergy's 500-kV line in the area was knocked out and the day prior when a conventional steam generator and large generator unexpectedly went offline. She agreed that the whole of spring was "very challenging" for MISO South.

Milton noted that the April 2 event was the result of severe weather that "parked" over the seam, compounded by planned, major transmission outages in SPP that dogged MISO operations in southwest Arkansas.

On May 25, MISO increased transmission demand curves on six different lines in an effort to entice more distant electricity supply to the area to no avail, she said.

The situation was made worse by online resources in the area that did not perform to their stated emergency ranges, she added. Milton also said MISO had no time to pinpoint which LMRs would have helped and said their lead times were prohibitively high anyway.

Milton said MISO should instate penalties for traditional resources that don't operate according to their stated emergency output values during an emergency, similar to the penalties it assigns to LMRs. "Currently, none exist."

MISO should also improve its locational awareness of LMRs so it knows which can help local system strain, she said.

Finally, Milton said MISO should set short-term reserve requirements for load pockets and develop a process to decommit resources that have a day-ahead schedule. Those two recommendations were included in the IMM's previous State of the Market reports.

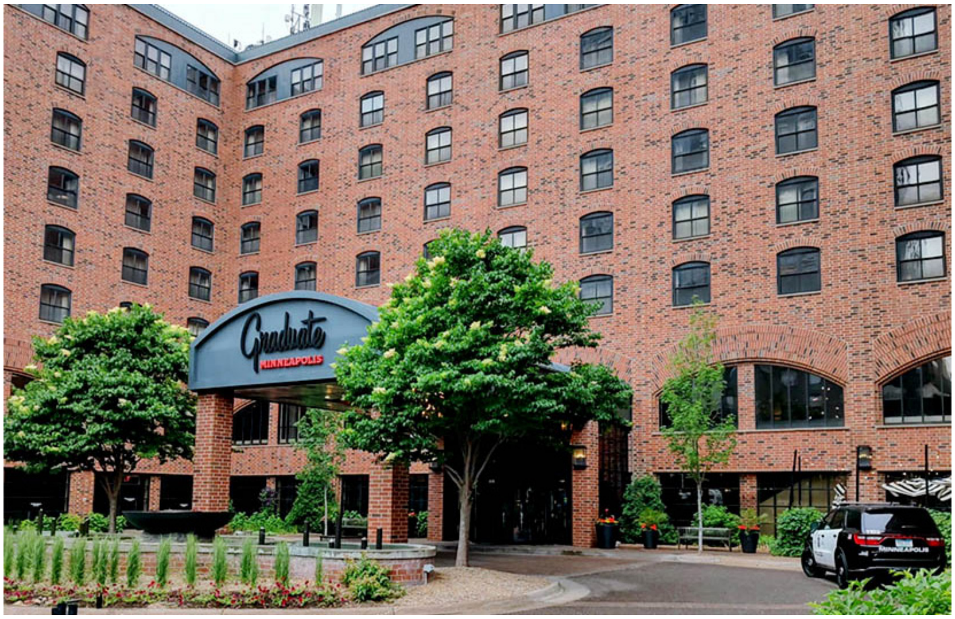
Transmission Planning Questions Crop up Again

Director Robert F. Lurie asked if the May 25 blackout might spur "investigations on the physical system" in southeastern Louisiana. He asked if MISO would consider expediting some planned transmission projects in the future or use a "blank sheet of paper" method to bring all ideas to the table to ease the constrained, load pocket situation.

Smith said the load pocket contained significant generation outages in addition to an inaccessible 500-kV line.

"It was a combination of so many things that got us to this point," he said. Nevertheless, he said MISO's planning team would run the probabilities of a similar situation occurring in the future and adjust accordingly.

In a later public comment period, the Union of Concerned Scientists' Sam Gomberg seconded the need for probabilistic planning. He said the shifting energy mix and more erratic weather



MISO's June Board Week was held at the Graduate by Hilton Minneapolis hotel. | © *RTO Insider*

courtesy of climate change demands more probability-based plans.

Former FERC Commissioner John Norris said MISO's tentative, 2026 start date on MISO South long-range transmission planning means the RTO would be planning regional transmission a full 15 years after Entergy joined. He reminded MISO that its core duty is planning transmission.

Now of counsel with Iowa-based *Horizon Group*, Norris said that in 2011, commissioners "were being gamed by Entergy," and since then he has seen "effort after effort to stall transmission" by Entergy. He said there's an "anticompetitive sentiment" in MISO South states and urged the RTO to recognize and "call out" Entergy's stalling tactics, which he said include bickering over cost allocation.

Norris said given what he knows now, he would not have cast a vote for Entergy to join MISO. He said at the time, "none of us could have conceived" that it would take 30 years to get new transmission to assist the Midwest-to-South constraint.

The Alliance for Affordable Energy's Yvonne Cappel-Vickery called on MISO to apply the same amount of transmission planning scrutiny to MISO South as it does to Midwest. She asked the RTO to ensure that "fair-weather load-shed events don't happen in area that already has enough weather challenges."

Cappel-Vickery reminded board members that even if MISO gets started on long-term transmission planning in MISO South within a few years, the first transmission lines won't be energized until about 2040.

Andy Kowalczyk, transmission director at the Southern Renewable Energy Association; said the load shed delivered "a stark reminder" that MISO South needs more than a "reactive posture" to its system reliability risks. He said recent transmission projects proposed by transmission owners there seem to be reactions to risks as they crop up and not "part of a long-term vision."

However, Bill Booth, a consultant to the Mississippi Public Service Commission, said MISO South utilities have recently invested billions in transmission projects.

The Holiday Weekend 'Curse'

Director Nancy Lange said she appreciated MISO's "candor" over its communication missteps. She asked if the RTO is contemplating how the region's collection of resources could better serve the area.

Smith said that if MISO had its proposed load-modifying accreditation in place, it may have helped. MISO is seeking to sort its LMRs into fast- or slow-start designations and call up slower resources before emergencies occur. (See *Stakeholders Ask FERC to Soften MISO's Proposed DR Accreditation*.)

However, Smith said he's not sure that LMRs would have made a noticeable enough difference for MISO to avoid tap-

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ping out generation stores in the area.

"We were fighting congestion and import limitations on the southeast Louisiana system," he said.

Director Barbara Krumsiek asked if MISO was reconsidering its usual spring outage season.

"We might be moving into a situation where planned outages in late May might have to be rethought," Smith said. However, he said planned outages weren't the main problem in this case. He said the unplanned generation outages coupled with the downed transmission were most burdensome.

Krumsiek asked if it was ironic that MISO's latest emergency again occurred on a holiday weekend. MISO has a long-running joke among its ranks that sticky situations arise on long weekends: Winter Storm Elliott near Christmas 2022, Winter Storm Uri on Presidents Day weekend in 2021 and the Gulf Coast *blizzard* that began Jan. 20 on Martin Luther King Jr. Day.

Director Theresa Wise joked that MISO is "cursed" on holiday weekends.

At the MISO Advisory Committee's meeting June 11, Arkansas Public Service Commission Administrative Law Judge Bridgette Frazier said that while the RTO isn't public-facing, Louisiana regulators are; it could have sent word to them to make public service announcements.

Pelican Power's Tia Elliott suggested MISO begin circulating one-pagers immediately following blackouts that explain in general terms the triggers and how they unfolded.

Cappel-Vickery said "it feels like a slap in the face" for MISO and Entergy to call the event rare when ratepayers in New Orleans regularly experience power outages.

"The typical consumer is not going to make the distinction that this is a transmission constraint versus this is a distribution-level event caused by, say, a squirrel," Cappel-Vickery explained.

She asked Entergy, MISO and Cleco Power to make a plan on how to prevent reliability issues going forward.

"We need better answers than 'we'll improve communications,'" Cappel-Vickery said.

Beyond Memorial Day weekend, MISO said heavy storms and tornado activity beleaguered its members throughout spring. Load, however, peaked at 95 GW on May 15, the most subdued it has been in years.

MISO's South and Central regions were under severe weather alerts for the first week of April, with MISO warning of freezing rain, cell formations, tornado outbreaks, high winds and hail. At the end of the month, all of MISO Midwest was under a severe weather alert because of thunderstorms, tornados and hail. Arkansas, southeastern Missouri and southern Indiana bore the brunt of large, long-lived storms.

MISO reported 61 GW of daily average generation outages over spring, the highest they've been in at least six years.

Entergy Arkansas reported a peak of 71,300 customer outages April 5 after the service area sustained five rounds of severe weather in a little more than a week. The utility reported widespread damage to substations, transmission towers, poles and wires. ■

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

By Amanda Durish Cook

MINNEAPOLIS — MISO Independent Market Monitor David Patton called NERC's Long-Term Reliability Assessment inaccurate for labeling MISO a high-risk area and said he believes MISO is in a good reliability position.

"We find that it is completely inaccurate. MISO should not be colored in red," Patton said at a June 10 Markets Committee meeting of the MISO Board of Directors.

Patton faulted NERC for apparently conflating installed capacity with unforced capacity in the assessment's totals. He said NERC tallied unforced capacity values for MISO when calculating a margin that it ultimately compared to an installed capacity requirement. He said the blunder lowered the footprint's capacity sums on paper by more than 10 GW.

"I don't frankly understand how they did this," Patton said. "They basically presented an apples and oranges assessment."

NERC's Long-Term Reliability Assessment predicted MISO could be confronted with capacity shortfalls in 2025. It assumed the RTO would have 132.2 GW in generating capacity, or 124.4 GW after factoring in all retirement announcements. (See *NERC Warns Challenges 'Mounting' in Coming Decade*.)

Ahead of summer, MISO reported it has 143.1 GW in offered capacity available to it to meet a likely 123-GW annual peak. (See *MISO Prepping for Likely 123-GW Summer 2025 Peak*.) Altogether, the RTO has 203 GW of installed capacity.

Patton said NERC's lapse is influencing national policy, evidenced by the Department of Energy's directive to keep Consumers Energy's 1.4-GW J.H. Campbell coal plant in Michigan operating over the summer. (See *Consumers Energy Seeking Compensation for Keeping Campbell Open*.) He said NERC's projection could bleed into other rule changes.

"That sort of initiative can lead to FERC ordering market changes that are unnecessary," Patton said.

Patton also said MISO overstated load predictions used in NERC's assessment by submitting non-coincident peak forecasts instead of coincident peaks, raising its load requirements and lowering the calculated capacity margin.

Patton said of the four RTO markets he monitors, "I would say MISO is most reliable of the four."

"It seems like a combination of errors that seems correctable here, but there isn't a path for correction," MISO Director Barbara Krumsiek said.

Patton said he hopes NERC will rectify its methods that inform the long-term assessment by the next December report. He said he has reached out to NERC and committed to working with the regulatory authority on its approach.

Michelle Bloodworth, CEO of coal lobby organization America's Power, questioned whether it was appropriate for the MISO Market Monitor to question a "credible institution" such as NERC. She said she believed MISO's "elevated risk" status under the assessment was apt.

Bloodworth praised the DOE's actions to keep J.H. Campbell available for a little while longer. She noted that Cleco's 568-MW Big Cajun II Unit 1 shuttered March 31 due to a settlement decree; she said having the coal plant online at the time might have helped matters during MISO's load shedding orders in the New Orleans area on May 25. (See *NOLA City Council Puts Entergy, MISO in Hot Seat over Outages*.)

At the same meeting, MISO said it likely will manage higher-than-normal temperatures paired with drought over the summer.

"If you're dry and have a pervasive heatwave going on, it can compound challenges in the operating room," MISO Executive Director of Market Operations JT Smith said.

Smith said a doubled-in-size solar fleet also likely will test MISO's ramp and regulation capabilities in its ancillary market. He said MISO operators could be managing unavailable resources and higher-than-expected load throughout summer.

Why This Matters

MISO IMM David Patton panned the RTO's precarious standing in NERC's Long-Term Reliability Assessment. He waved away resource adequacy concerns and said NERC botched a margin-to-capacity requirement comparison, apparently mixing up unforced capacity and installed capacity.

As part of a five-year update, Vice President of Operations Renuka Chatterjee said MISO finds itself in the most "dynamic and demanding" operating environment it ever has. She cited steeper evening ramps and mounting long-duration outages, forecasting challenges and stability risks.

MISO entered summer June 1 with a $666.50/MW-day capacity price, signifying the premium the RTO has put on new capacity. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

Carrie Milton, of the IMM staff, said if generation operators had held off on powering down about 1.6 GW until September, it would have lowered capacity prices to $472/MW-day in the summer.

But Milton said the Campbell plant is not factored into MISO's clearing prices and isn't necessary for reliability during the season. She said MISO's auction already returned a better than one-day-in-10-years standard without the large coal plant.

"We are more than adequate," Patton said. He repeated that he has "no material concerns" over MISO's resource adequacy for the upcoming summer.

Patton said factoring in imports and typical planned and forced outages, MISO has a comfortable, 12.2% reserve margin. ■

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N.Y. OKs 642 MW of Urgent Infrastructure Upgrades

Projects Estimated at $636M Will Support Building, Transportation Electrification

By John Cropley

New York has authorized its first tranche of projects under a 2024 order that sought to address urgent existing and anticipated electric infrastructure needs as the state pushes to decarbonize transportation and buildings.

The 29 projects chosen are intended to expand capacity by 642 MW at an anticipated cost of $636 million, or about $1 million per megawatt. They were winnowed down from 65 proposals rated at 1,290 MW that would have cost $1.88 billion, or $1.5 million per megawatt of new capacity.

The Public Service Commission voted unanimously to approve the work at its June 12 meeting (*Case 24-E-0364*).

Most of the projects are in upstate New York, but much of the spending and much of the new capacity will come through five Con Edison upgrades in a few square miles of New York City facing immediate constraints.

Con Edison said extensive transportation electrification in an area of the South Bronx requires urgent near-term distribution system, sub-transmission and area station investments.

The area is dotted with fleet depots and service centers that serve an estimated 15,000 commercial vehicles, some of which are expected to electrify and some that already have.

There also is the largest-of-its kind Hunts Point Food Distribution Center, target of multiple electrification initiatives including a freight-focused charging facility and development of dozens of DCFC and L2 plugs.

Why This Matters

The projects address the infrastructure needs emerging as New York pushes to electrify structures and vehicles.

Con Edison's five projects would increase capacity by 380 MW at an estimated cost of $440 million.

The PSC in its August 2024 order directed the state's large investor-owned electric utilities to begin the process and identify urgent needs. (See *New York Orders Utilities to Join in Proactive Grid Planning*.)

Con Edison, National Grid, NYSEG and RG&E submitted the 65 proposals; Central Hudson and O&R indicated they had nothing "urgent."

Department of Public Service staff rejected more than half the proposals for not meeting one or more of the evaluation criteria:

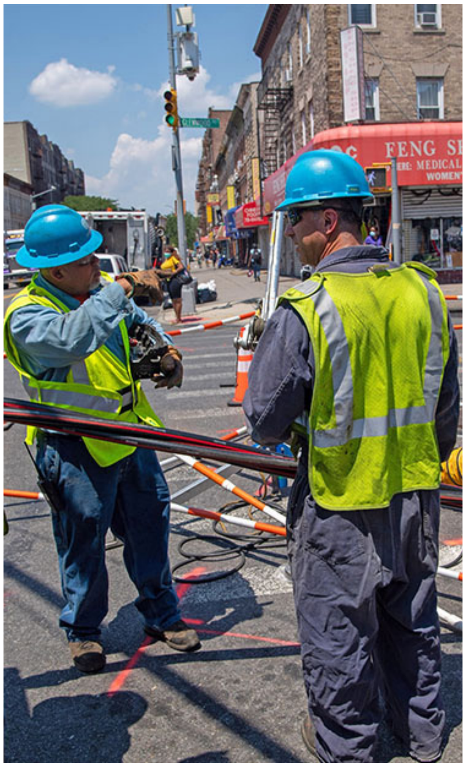
- The work is needed to meet anticipated load growth from building electrification and/or transportation electrification.
- Construction-related activity could start by July 1, 2026.
- There is a high degree of certainty about location, magnitude and timing of load.
- There is demonstrated consideration of risks and benefits of the size and timing of the proposed action, and of delaying that action or not taking it at all.

The 36 proposals that did not meet all four conditions may be able to advance later on a path other than this urgent/proactive process.

"We are approving these projects today because significant grid capacity is needed to support electrification across vehicle duty classes and buildings," PSC Chair Rory M. Christian said in a news release. "Grid constraints have already begun to limit electrification in some parts of the state. The urgent grid upgrade projects would expand grid capacity in many areas of the state, relieving urgent constraints on an accelerated basis while a broader, unified planning framework is developed."

One project each was authorized for NYSEG and RG&E.

NYSEG's Kent Falls project would add 30 MW of capacity at a cost of $37.1 million



Con Edison

to support a large and expanding manufacturing facility.

RG&E's Station 124 project in Penfield would add 47 MW of capacity at a cost of $33.2 million to address electric vehicle charging needs and growth of existing loads in the Rochester area.

PSC approved 22 National Grid proposals with a combined capacity of 185 MW and estimated cost of $126 million — most of them small, but with a few station rebuilds and other larger projects included.

Among them is an "innovative" bridge-to-wires project that involves 4.4 MW of mobile battery energy storage systems. It would address immediate constraints, support transmission electrification and provide flexibility while a substation solution is developed for the longer term. At $21.6 million, its estimated cost per megawatt is nearly five times the average of the projects authorized June 12.

The most expensive project by capacity on the list would support a load request by a depot serving a school bus fleet that is being electrified to meet a state mandate. At 2.2 MW and $15 million, it would cost $6.8 million per megawatt. ■

NYISO Stakeholders Propose Capacity Retention Market

Budget and Priorities Working Group Continues Project Prioritization

By Vincent Gabrielle

Central Hudson, Con Edison, National Grid and the Natural Resources Defense Council have co-submitted a proposal to the NYISO project prioritization process asking that the ISO consider developing a capacity market based around retaining existing resources.

The project *proposal* says the market is intended to operate within a framework where generator entry to the New York market is driven by state government procurements. Various stakeholders have contended in prior working group meetings that the capacity market as currently designed ignores this and as a result no longer functions to incentivize new entry. (See *NYISO Stakeholders Debate Purpose of Capacity Market*.)

"Given the dominant role of the state, we think it would be prudent to consider the merits of, and efficiencies that we might gain, by focusing the capacity market on the cost of retention today," said Ekene Umeike, speaking on behalf of Con Edison.

During his presentation, Umeike said the project would replace the elements of the capacity market structure review that are considering a bifurcated market. Such a market could implement price discrimination between new and old capacity.

"The proposal recognizes that the implementation of a retention-only capacity market would require the development of separate mechanisms for market entry," Umeike said. "While other capacity market programs have been proposed, in our view, none of them appear likely to address the fundamental concern of customers facing higher costs without a commensurate improvement in reliability."

Several stakeholders asked for clarification on the project and how it fits into the current project prioritization process. One stakeholder asked that Con Edison and the other co-sponsors of the proposal come to the ICAP working group to discuss elements of the project and its description before asking stakeholders to vote on it.

Project Prioritization Continues

NYISO has included 48 "*market projects*" in the project prioritization process. Of those, 25 focus on changes to the energy market, 10 to the capacity market and seven to new resources. The remainder focus on planning and transmission congestion contracts markets.

NYISO staff added several new projects to the pool of potential candidates for focus in 2026, including designing a market mechanism for bifurcated capacity markets and the net congestion rent assignment study proposed by the MMU. (See *MMU, FTI Argue for Maintaining Uniform Pricing in NYISO Capacity Market* and *NYISO Monitor Proposes Changing Congestion Rent Assignments*.)

A list of project descriptions can be found *here*. Project costs and descriptions still are in draft form and will be finalized by June 30. After that, NYISO will distribute surveys to stakeholders for project scoring. These surveys are due July 15 and survey results will be discussed July 30. ■

NYISO Monitor Proposes Changing Congestion Rent Assignments

The NYISO Market Monitoring Unit is *proposing* to revise the ISO's net congestion rent assignment process by allocating residuals to transmission owners on an individual facility basis.

Congestion rent is collected by the ISO from load and paid out through transmission congestion contracts (TCCs). Residuals can arise when there is a difference in internal transfer capability between the day-ahead market and what was assumed in the TCC auctions. They represent the difference between the congestion rent required to fund payments to TCC holders and the amount of rent collected.

Currently residuals are assigned to TOs

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depending on the reason for the congestion, and some situations leading to residuals are socialized among TOs based on their respective shares of TCC auction revenues. Under the MMU's proposal, however, "the TO that owns the 'offending' transmission facility would absorb or pay the shortfall associated with their facility," it said.

The MMU says this would improve the incentives for transmission investment and operating grid-enhancing technologies, and reward efficient transmission operations, including line switching.

NYISO is on board with the change, but it needs to do a significant amount of modeling and simulating of the change's impacts on the markets first. The ISO plans to propose a dedicated "Net Congestion Rent Assignment Evaluation" project as part of its 2026 prioritization process. ■

— Vincent Gabrielle

N.J. Lawmakers Bless Wide-ranging Energy Options

Nuclear, Tidal, Storage Proposals Backed as State Addresses Power Shortfall

By Hugh R. Morley

New Jersey legislators, responding to fears of a dramatic shortfall in electricity, have pushed ahead with a series of legislative proposals, among them plans to harness wave, nuclear and storage power.

The Assembly Science, Innovation and Technology Committee backed *A4215*, which would direct the New Jersey Economic Development Authority to create an incentive program to stimulate the construction and operation of small modular nuclear reactors (SMRs).

The legislation defines eligible projects as nuclear fission reactors that can generate up to 300 MW of electricity and are licensed by the U.S. Nuclear Regulatory Commission. They can be built and operated independently or in conjunction with other reactors.

The bill also would direct the New Jersey Board of Public Utilities (BPU) to adopt regulations for the reactors and to study issues such as whether a nuclear reactor would replace a loss of generating capacity due to the closure of a fossil fuel facility. It also directs the BPU to look at whether such projects can use existing land and infrastructure.

New Jersey State House in Trenton, N.J. | *Shutterstock*

Ray Cantor, senior lobbyist for the New Jersey Business & Industry Association (NJBIA), told committee members his organization backs the bill as a way to address the forecasted power shortage.

"We support an all-of-the-above approach to energy, but we believe that nuclear power and SMRs are part of the future," he said. "I wish we had pursued this many years ago, and we would not be in the situation we're at right now."

Nuclear Power Advisory Commission

New Jersey is an electricity importer. PJM says fossil fuel generators are closing far faster than new — mainly clean energy — facilities open. That's occurring as demand is expected to rise from data centers, electric vehicles and building electrification.

The state had counted on the development of its offshore wind sector, with a planned capacity of 11 GW of power, to boost in-state generating capacity. But the plans have stalled, initially stymied by rising costs and supply chain problems, and now by President Donald Trump's moves to shut down clean energy development.

Several other bills advancing through committees would, if enacted, expand the state's community solar program, boost the development of storage capacity through an incentive program and require the state to study the viability of generating electricity with ocean wave and tidal power.

The Senate Environment and Energy Committee backed *S220*, which would set up a seven-member Nuclear Power Advisory Commission inside the New Jersey Department of Environmental Protection. The commission would consider issues such as "the value of nuclear energy generation as a reliable, zero-emission source of energy." It also would look at the impact of the closure of existing nuclear plants, emerging technologies in reactor designs and the viability of small-scale nuclear plants.

The Legislature is considering another nuclear bill, *S4423*, that would authorize the BPU to give site approval for an SMR in a municipality where a nuclear facility previously was located. (See *N.J. Advances Nuclear, Data Center Legislation*.)

Harnessing Wave and Tidal Power

The shift toward nuclear, while favored by Democrats and Republicans, is considered a longer — and more expensive — play than other options. Some advocates believe solar energy is the quickest, cheapest way to develop new energy generation.

To that end, the Senate Environment and Energy Committee advanced a bill, *S4530*, that would direct the BPU to open registration by Aug. 1 for an additional 3,000 MW of community solar projects, removing the state's existing annual goal of 150 MW of new capacity a year.

The BPU would set solar renewable energy certificate levels to ensure the full capacity is awarded by Dec. 31, 2029.

The Assembly Telecommunications and Utilities Committee approved a similar bill, as well as a bill, *A1478*, that directs the BPU to study and promote the harnessing of ocean energy, in particular wave and tidal power.

The legislation would direct the agency to conduct a "comprehensive study" of the topic and incorporate wave and tidal energy generation into the state Energy Master Plan. The agency also should look at the "feasibility and desirability" of establishing a program to stimulate development of ocean-based projects by awarding wave renewable energy credits, similar to the way solar renewable credits are awarded.

Assemblyman Paul Kanitra (R), whose district sits on the Jersey Shore, balked at the suggestion, saying he saw parallels to the way he believes offshore wind projects would impact his district. He expressed concern about "how much is this going to industrialize the ocean? How is it going to affect our marine and fishing industries?"

Committee Chairman Wayne P. DeAngelo (D) said the pilot program and the study would address those kinds of questions.

But Kanitra, who abstained from voting, also questioned the cost of the study, worrying that "as it was with offshore wind, I'm assuming that there's somebody sitting here in the audience right now whose company probably stands to make a ton of money on this situation, and I'd love to have some clarity on who that is."

Assemblyman Christian E. Barranco (R), the sole vote against the bill, called it a "half measure" considering the seriousness of the state's position as a "desert of electrical energy."

"This is an energy experiment," he said of the bill, adding that the state needs "robust fired generation."

"This is not going to help us in any way with the freight train that we're facing of electrical costs in New Jersey," he said. "Everything that takes away from the fact that we need generating assets, turbines spinning right now, is getting in the way of what we need to do to make sure we don't go broke paying our electric bills."

Data Center Tariff

The Assembly committee also approved *A5462*, which would require the BPU to develop a tariff for data centers. The bill aims to protect ratepayers from footing the cost of meeting demand from data centers. It also seeks to "incentivize data centers to develop and utilize methods to increase energy efficiency, including through the use of technologies that capture and utilize the heat produced by the data center."

Jasmine Metellus, a lobbyist for the New Jersey League of Conservation Voters, said the bill not only would "provide an incentive for data centers to drive down consumption, but would protect ratepayers from shouldering an unfair burden."

"We don't have enough (electricity) to host the data centers," she said. "Data centers anywhere on our grid will drive up the cost."

Storage Expansion

The Senate Budget and Appropriations Committee supported *S4289*, which would require the BPU to "establish a program to procure and provide incentive awards for the development of transmission-scale energy storage systems" that are likely to be completed in a timely manner.

Clean energy advocates consider storage essential to providing energy when wind and solar cannot, and to helping meet sudden peaks in demand.

The bill would make storage systems eligible for support if they have a capacity of at least 5 MW, are connected to the PJM transmission network and are "qualified to provide energy, capacity or ancillary services in the wholesale markets established by PJM Interconnection."

The bill would require the BPU to procure at least 1,000 MW of installed capacity by June 30, 2026, with 350 MW procured by Dec. 31, 2025, and the remainder by June 30, 2026.

The BPU for more than two years has been considering the issues involved in a storage incentive program. The state missed a legislative goal of developing 600 MW of storage by 2021 and now is seeking to put 2,000 MW of storage in place by 2030. (See *Developers Seek Deadline Extension in NJ Storage Plan*.)

Pam Frank, speaking at the hearing for the American Clean Power Association, said the bill, by helping install grid-scale storage, could save ratepayers tens or hundreds of millions of dollars by avoiding the use of high-cost power at peak times.

But Brian Lipman, director of the New Jersey Rate Counsel, said he's concerned the proposed program would be overpaying, with incentives that he calculated at $900 million over 15 years. "While some incentive may be needed, we are not convinced that this is the right amount," he said in an interview with *RTO Insider*.

Sen. Declan O'Scanlon (R) opposed the bill, saying he needs clarity on the cost to ratepayers.

"We definitely have confusion of whether this will increase cost, decrease cost," he said. This and other energy bills are designed to make up for "this administration's woeful lack of planning for our energy future" and its excessive focus on wind generation.

In response, Sen. Paul Sarlo (D), the committee's chairman, said storage should be part of the "more balanced approach" the state needs in its energy delivery strategy.

"And if it's a combination of solar with battery power, more battery storage, combination of continuing to buy natural gas — it's something that we need to all move on," he said.

Backing the bill, Sen. John Burzichelli (D) said PJM has been "continually hesitant to let solar in the system without battery backup."

"PJM wants power that's ready on demand, no matter what time of year and no matter what the weather circumstances are," he said. He called the position "very reasonable" given their responsibility to provide power. "The issue of this battery storage, and the legislative voice, [is] saying, 'Look, this has got to be a priority.'" ■

Talen and Amazon Enter PPA for 1.9 GW of Power from Susquehanna

By Devin Leith-Yessian

Talen Energy and Amazon Web Services (AWS) have entered into a power purchase agreement (PPA) for the Susquehanna nuclear generator to supply 1.9 GW to the tech company as its retail supplier.

"Amazon is proud to help Pennsylvania advance AI innovation through investments in the commonwealth's economic and energy future," AWS Vice President of Global Data Centers Kevin Miller said in an *announcement* of the June 11 agreement. "That's why we're making the largest private-sector investment in state history — $20 billion — to bring 1,250 high-skilled jobs and economic benefits to the state, while also collaborating with Talen Energy to help power our infrastructure with carbon-free energy."

The agreement is effective through 2042 and will ramp up to the full 1,920 MW by 2032. The announcement states the two companies will explore possible uprates to the generator, as well as the installation of small modular reactor (SMR) resources within Pennsylvania.

"This long-term transaction will significantly decrease Talen's market risk and minimize its reliance on the federal nuclear production tax credit," the announcement states.

Talen Energy's Susquehanna Steam Electric Station located in Salem Township, Pa. | *Talen Energy*

Why This Matters

The 1.9-GW power purchase agreement between Talen Energy and Amazon Web Services is the latest in a series of nuclear generators contracting their output to serve data centers.

The deal ratchets up a partnership between the two companies that includes a data center co-located with Susquehanna, an arrangement Talen has sought to expand. FERC rejected an amendment to Susquehanna's interconnection service agreement that would have increased the amount of power serving the co-located load from 300 MW to 480 MW. (See *FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant*.)

Following a configuration of the transmission around Susquehanna in spring 2026, the co-located data center would shift from being behind the generator's meter to receiving full grid service. The change will occur at the same time as the generator's scheduled refueling outage.

"Our agreement with Amazon is designed to provide us with a long-term, steady source of revenue and greater balance sheet flexibility through contracted revenues. We remain a first mover in this space and intend to continue to execute on our data center strategy," Talen CEO Mac McFarland said. "Talen is well positioned to support Amazon's energy needs as it invests further in the Commonwealth of Pennsylvania."

Susquehanna would remain available for PJM dispatch under the PPA, with transmission and distribution service provided to the data centers by PPL.

"PPL Electric Utilities is investing in the resiliency of its transmission system so we can better serve our customers, meet growing energy demands and ensure power is delivered reliably," PPL Electric Utilities President Christine Martin said. "Connecting large load customers like

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data centers to our transmission system helps lower the transmission component of energy bills for all customers, as large load customers pay significant transmission charges on our network. We're excited to be part of Amazon's broader investment in Pennsylvania and look forward to the positive effects it can have for our customers and the local economy."

In an analysis of the transaction, financial firm Jefferies said it believes front-of-meter deals will become the norm going forward. The firm estimated that when the transaction fully ramps up, it will be worth between $82 and $88/MWh, higher than Jefferies' earlier $75/MWh estimate and above other recent PPAs between nuclear operators and tech companies.

"We believe this puts to bed the debate on BTM nuclear in PJM, consistent with our long-held view. We expect FTM involving hyperscaler companies paying full transmission charges or virtual (i.e. financial/carbon deals) in future transactions," Jefferies wrote.

Siting data centers behind generators' meters has been a point of contention for state regulators and FERC. Proponents have pushed for clearer rules on the practice and argued it would increase the efficiency of the grid, reduce network upgrades and create flexibility for loads that don't require all the characteristics that come with full network service.

Opponents say co-location could allow the load to avoid paying for ancillary services, like regulation or black start, that they consume. PJM also has posed engineering challenges with behind-the-meter load, saying its rules are designed for small configurations and protective relay failures could cause reliability issues.

Nuclear generators have been of particular interest to data centers looking for co-location opportunities or PPAs. Meta and Constellation energy announced a PPA on June 3 for the output of the 1,121-MW Clinton nuclear generator in Illinois, and another Constellation deal with Microsoft is set to revive the Three Mile Island Unit 1 as the Crane Clean Energy Center. (See *Constellation, Meta Sign 20-year Nuclear PPA*.)

Pennsylvania Gov. Josh Shapiro (D), U.S. Sen. Dave McCormick (R) and U.S. Rep. Dan Meuser (R) threw their support behind the agreement in the announcement.

"My administration is going to continue to bring people together to attract new investment to Pennsylvania, and we stand ready to work with Talen Energy and its partners to review permits for this project as efficiently as possible," Shapiro said. ■

PJM MRC/MC Preview:

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

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

Markets and Reliability Committee

Consent Agenda (8:30-8:35 a.m.)

B. Endorse proposed *revisions* to Manual 12: Balancing Operations drafted through the document's periodic review, updating the operating mode change procedure and requiring the PJM master coordinator to be notified of any change in output for self-scheduled units when NERC tags cannot be processed. The changes also include conforming changes to PJM's hybrid resource rules. (See "Manual Revisions Endorsed," *PJM Operating Committee Briefs: June 3, 2025*.)

C. Endorse proposed *revisions* to the tariff, Reliability Assurance Agreement and Operating Agreement as endorsed by the Governing Document Enhancement and Clarification Subcommittee. The changes would remove obsolete references and terms, align cross-referenced language and codify the second phase of PJM's hybrid resource rules.

Endorsements (8:40-9:30 a.m.)

2. Manual 14H: New Service Requests Cycle Process Revisions (8:40-9:05 a.m.)

PJM's Jonathan Thompson will present proposed *revisions* to Manual 14H: New Service Requests Cycle Process to rework the RTO's site control requirements in accordance with a settlement *approved* by FERC on June 10 (*ER25-1544*). (See *PJM Presents Settlement on Site Control Requirements*.)

Issue Tracking: *Site Control Modification Clarification*

3. Storage Integration (Phase II): Transmission Asset Utilization in Operations (9:05-9:30 a.m.)

PJM's Dave Anders will present a *problem statement* and *issue charge* that would open a stakeholder process to consider establishing rules for deploying battery storage as a transmission asset (SATA). Constellation Energy's Juliet Anderson will present an alternative *issue charge*, which differs on identifying the use-case for SATA, when the batteries would operate and identifying and mitigating market impacts. (See "Stakeholders Torn on Further SATA Education," *PJM MRC Briefs: May 21, 2025*.)

Members Committee

Endorsements (4:40-5:30 p.m.)

5. CIFP — DOE 202(c) Cost Allocation (4:40-5:30 p.m.)

A. PJM and the Members Committee will review proposals to determine how the cost for Constellation to continue operating its Eddystone Generating Station under a Department of Energy emergency order will be allocated to consumers. Solutions may include a broad cost-allocation paradigm for any future emergency orders.

B. The committee will vote on whether to recommend each proposal to the Board of Managers, with results not shown on any package until full voting is complete. ■

PJM Stakeholders Propose Cost Allocation Models for DOE Emergency Orders

By Devin Leith-Yessian

The PJM Members Committee is set to vote on several *proposals* drafted by the RTO and stakeholders to determine how to allocate costs associated with generators required to remain online through the U.S. Department of Energy's emergency orders under Federal Power Act Section 202(c).

Package sponsors, RTO staff, the Independent Market Monitor and other stakeholders will meet with PJM's Board of Managers just before the committee's meeting June 18 as the final phase of an expedited Critical Issue Fast Path (CIFP) process initiated to determine how to raise the funds to compensate Constellation Energy for continuing to operate its 760-MW Eddystone Generating Station, which DOE ordered to remain online past its May 31 deactivation date through Aug. 28.

Constellation and PJM agreed to use the deactivation avoidable cost credit (DACC) model used to compensate resources retained past their deactivation date on reliability-must-run agreements. The allocation methodology associated with the DACC, however, is designed for assigning costs to load in the region of the transmission violations leading to an RMR arrangement; PJM has said it is not suited to instances where the federal government mandates a generator remain online for resource adequacy. (See *PJM Board Initiates CIFP Process for Eddystone Compensation*.)

PJM proposed to allocate the costs to all RTO load by dividing each market buyer's share of the RTO-wide unforced capacity (UCAP) obligation and multiplying that figure by the credit to Constellation. A new line item would be added to billing statements to show the cost of 202(c) credits, with information also posted to PJM's website. During the CIFP meeting June 12, PJM Senior Director of Market Settlements Lisa Morelli said the RTO had estimated the 90-day cost to load to be $34.72/MW of UCAP.

Why This Matters

Stakeholders are divided on whether the expedited CIFP process should focus only on the Department of Energy's order to keep the Eddystone Generating Station online or contemplate possible future orders.

Package D from the East Kentucky Power Cooperative would assign costs to all RTO native load and exports using actual megawatt-hour consumption per month unless the resource subject to the 202(c) order is within a zone that fell short of its capacity procurement obligation — in which case the costs would be allocated to that zone — or if the RTO cleared short of its obligation, in which case costs would be assigned to each locational deliverability area (LDA) according to their contribution to the shortfall. The charges would be calculated by adding a market buyer's energy consumption and exports and dividing that sum by total monthly energy production, then multiplying that by the credit to Constellation. Resources exporting to external balancing authorities they have capacity obligations to would be excluded.

The cooperative's Package E would assign costs to each buyer according to the same formula regardless of how each zone cleared in the capacity market.

Stakeholders were divided on whether the proposal should focus solely on compensating Constellation for operating Eddystone under the current emergency order or establishing rules for other resources subject to a 202(c) order. Morelli said establishing more lasting rules would carry the benefit of avoiding additional rushed CIFP processes if additional resources are ordered to remain online.

Two PJM packages would apply more broadly, though with differing criteria; Package A would apply to all DOE orders under Section 202(c) in which the resource owner opts to be compensated through models similar to the DACC, while Package C would limit that to orders issued within 180 days of PJM filing the cost allocation proposal. Morelli said establishing a time limit for the proposal would give time for stakeholders to continue discussions for a more holistic solution without the result of the CIFP becoming permanent.

Lisa Morelli, PJM | © *RTO Insider*

Package B from Gabel Associates and EKPC's Package E would limit the changes to the Eddystone order expiring on Aug. 28. Package D from EKPC would apply to all units subject to a 202(c) order not subject to an RMR agreement and being compensated through models akin to the DACC.

Proposals with a wider applicability also differed on how they would allocate costs if future DOE orders specified a region within PJM where localized resource adequacy concerns prompted the need to retain a generator beyond its desired deactivation date. PJM's packages would assign the charges only to load in the LDAs or zones identified, while Gabel would continue to allocate them to all RTO load.

Stakeholders opposed to a locational element to allocating costs argued that Eddystone is not being retained to serve a particular zone and future orders could retain generation for resource adequacy issues that have not yet manifested. ■

PJM Proposes Changes to Large Load Forecasting

By Devin Leith-Yessian


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

PJM *presented* changes to its submission and review processes for large load adjustments (LLAs) that are intended to provide stakeholders with more transparency before they are included in future load forecasts, as well as a draft *proposal* to standardize how it determines what share of LLAs will be included in its forecasts.

Under the revised timeline, the Load Analysis Subcommittee (LAS) would review LLA submissions in September, rather than October, to allow more time for stakeholders to discuss the data provided by electric distribution companies and load-serving entities. PJM would open the submission window on July 1, with responses expected by early September.

Under Manual 19 Attachment B, PJM currently sends the request for LLA submissions in mid-July, with a meeting to review the responses at the LAS in September or October.

Presenting to the LAS on June 10, PJM's Molly Mooney said the changes center around processing LLA submissions earlier in the load forecast schedule to allow more time for RTO staff and stakeholders to see the impact they may have on reliability studies. She said the timeline will provide "a little extra time will give us more wiggle room internally to give an early warning to the impact these large loads will have on that reliability impact study."

Mooney said adjustments accounting for concentrated data center growth have led to many stakeholders submitting inquiries to PJM, and the proposal is aimed at providing more transparency around how those LLAs are developed and processed by the RTO. (See *Panel Discusses Data Center Load Growth at PJM Annual Meeting*.)

Why This Matters

PJM plans to revise its large load adjustment process with the aim of making it more standardized and transparent as stakeholders are putting a focus on how growing data center load is reflected in the RTO's annual load forecasts.

PJM is also considering *revising* the language of the request it sends to EDCs and LSEs soliciting LLAs to standardize the process, providing more guidance on the information PJM is looking for and how it would seek to fill in any gaps.

Submissions would be asked to identify the amount of load in both demand and capacity terms. If only expected capacity values are provided, PJM would use historic data to determine a demand value. The change would also ask that adjustments include the amount of time it would take for a project to ramp up to its full load, with a default of three years if no estimate is provided.

PJM may derate the amount of load it expects to come online based on the likelihood of the consumer entering service. Projects coming online within three years and that have made electric service obligations or construction commitments to the EDC or LSE may be included in the load forecast. Projects with in-service dates between three and eight years into the future may be derated if the consumer has not made those commitments or provided evidence of "demonstrable project milestones." Longer-term LLAs may be submitted using expected agreement flows or extrapolations with proper substantiation.

For projects being derated, submissions should include a probability factor detailing how far a project has advanced toward completion, such as site control, state support, transmission upgrades or financial commitments. Without that information, PJM may use a default probability of 50% to derate the project.

The change would also establish a 50-MW floor for LLA submissions, though Mooney noted that NERC is considering its own threshold. Smaller adjustments would still be permitted on a case-by-case basis.

Calpine's David "Scarp" Scarpignato said he worries that derating expected energy by as much as 50% could risk undercounting much of the load that is likely to come online, undermining the accuracy of the forecast.

PJM's Andrew Gledhill responded that when the RTO implements its long-term, regional planning proposal to comply with FERC's Order 1920, it could include scenarios looking at both high and low data center penetration. (See *FERC Order 1920 Sees Wide-ranging Rehearing Requests*.) ■

FERC Clarifies SEEM Ruling, Denies Rehearing

Commission Explains Use of Comparability Standard

By Holden Mann

In a response to opponents of the Southeast Energy Exchange Market, FERC on June 13 clarified the legal standard it relied on in its March 14 order directing SEEM members to update the market agreement (*ER21-1111*).

In doing so, the commission also dismissed the opponents' alternative request for rehearing of the order, arguing it was moot given FERC's clarification, and improper under the D.C. Circuit Court of Appeals' 2020 ruling in *Allegheny Defense Project v. FERC* that rehearing requests could not be granted "for the limited purpose of further consideration."

The SEEM opponents, a group of 13 organizations including the Sierra Club and the Southern Alliance for Clean Energy filing jointly as the ad hoc Public Interest Organizations (PIOs), filed their request April 14, the same day SEEM's members responded to the March 14 order. (See *SEEM Opponents Urge FERC for Clarification*.) FERC's order mandated updates to the market agreement to clarify its territorial requirements and outline whether pseudo-ties could be used to satisfy them.

The PIOs claimed one part of the order — in which FERC said SEEM's open access transmission tariff is "consistent with or superior to the *pro forma* OATT" based on the commission's comparability standard — was inconsistent with precedent.

According to the PIOs, the comparability standard as first described in 1994 meant that an OATT "should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system." However, in the March 14 order, FERC said the standard "requires that comparable service be provided to comparable customers."

Because the phrase "comparable customers" never has been used in reference to the comparability standard, the PIOs argued the commission effectively invented a new definition to apply to SEEM.

FERC denied it had redefined the standard but agreed it would be "appropriate" to clarify its reasoning. The commission said it was guided by Order 888's articulation of the comparability standard, which said that "under a non-discriminatory open access tariff, a transmission provider must not only treat similarly situated customers similarly but also provide third parties with comparable service to what they provide themselves."

"To the extent that … the March 2025 order can be read otherwise, we clarify that these are the standards the commission applied in reviewing SEEM," FERC said.

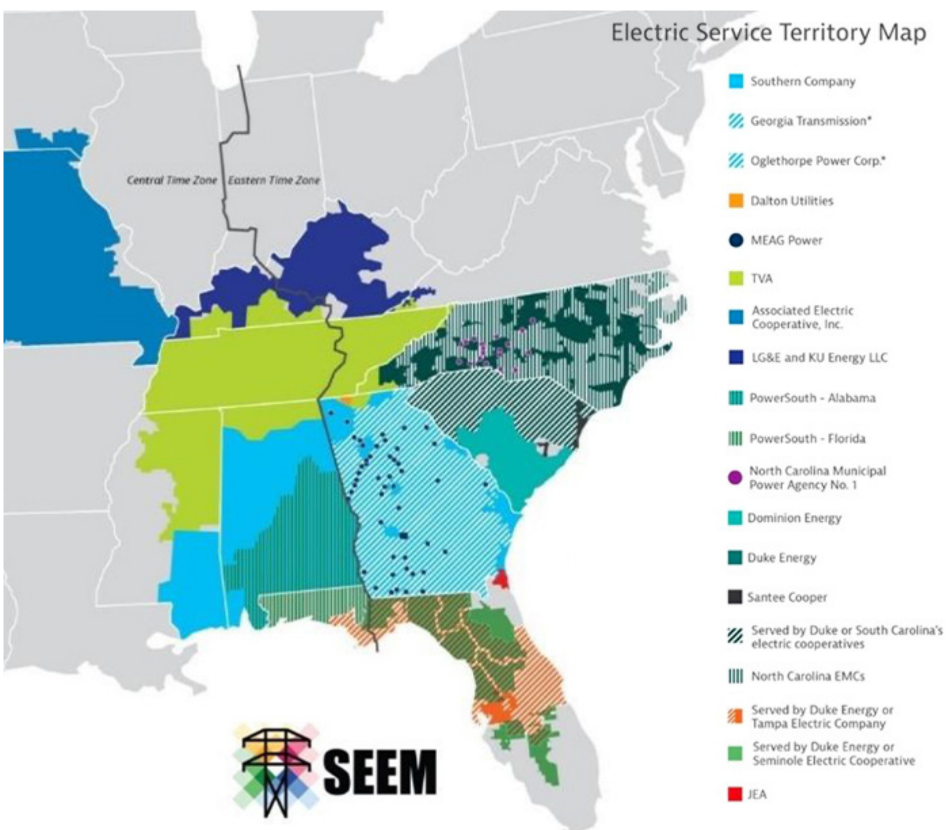
The commission went on to "confirm that … SEEM affirmatively meets the comparability requirements because it offers comparable service to SEEM members … and participants, both of which must take service under the same terms and conditions."

FERC said the question before it in the proceeding was whether all "similarly situated entities" that wanted to participate in SEEM were treated similarly, and that the territorial requirements do not amount to dissimilar treatment because entities outside the SEEM territory "are not similarly situated" to those inside.

Commissioners concluded the clarification of its language "does not impact the outcome of the March 2025 order," which SEEM members addressed in their April 14 filing. (See *SEEM Members File Market Agreement Update*.) ■

Why This Matters

Opponents of the Southeast Energy Exchange Market have criticized the market since its inception in 2021, saying its structure provides monopolistic power to larger utilities without providing any of the promised cost benefits or incentives for clean energy.



Map of the Southeast Energy Exchange Market's footprint. | *SEEM*

SPP Embraces Need for Speed to Meet Change Head-on

Large Loads, Executive Orders Add to Pressure on Industry

By Tom Kleckner

Evolutionary, not revolutionary. That's long been one of SPP's value propositions. Work with stakeholders to reach consensus, making sure things are done the right way and at the right time.

No more.

The "evolutionary, not revolutionary" language was removed from SPP's five-year strategic plan, *Aspire 2026*. CEO Lanny Nickell alluded to the concept when he opened a June 13 education session for the grid operator's state regulators by sharing details on things he characterized as "revolutionary."

"The industry is changing at a pace that I've not seen in my 33-year career," Nickell told the Regional State Committee. "That's not news. It's what is behind our need to move faster."

That and recent executive orders from the administration to *strengthen the grid's reliability and security* and to "*protect American energy from state overreach*," Nickell said, have only amplified the pressure on the industry. (See *Trump Seeks to Keep Coal Plants Open, Attacks State Climate Policies*.)

"We are feeling the pressure. I'm sure you all feel some pressure as well, even within your own states," he told regulators. "And when the federal government says, 'We desire to be an energy-dominant nation,' those words create some risk for us. If we don't figure out how to do that, if we don't figure out how to move faster to help our utilities attract loads, they'll go somewhere else. And if the federal government's not excited about how that's happening and they see the RTOs as being resistants and not lubricants, then that's a risk to us and it's a risk to our utilities."

Lanny Nickell wants to speed things up at SPP to meet the pace of industry change. | © *RTO Insider*

Why This Matters

SPP has long practiced an evolutionary, not revolutionary, approach to its stakeholder process. However, the pace of industry change has forced the RTO to recalibrate. It now is working to streamline the stakeholder process and make things happen faster.

Topping the list of SPP's revolutionary items is how best to add large loads to the system, a task facing every RTO or ISO in the U.S. The board of directors in May directed the grid operator's staff to present their proposal for interconnecting data centers and crypto miners during its August meeting.

Nickell said he thinks staff can beat that deadline. The RTO has scheduled a virtual *stakeholder engagement forum* on July 1 to explain how it will facilitate the "timely and efficient integration" of large loads.

SPP has scheduled another education forum July 15 in Little Rock, Ark., to gather feedback on a proposed demand response policy. It said a related tariff revision is being developed and soon will be available for stakeholder input.

"We're hoping to not upset the cost-allocation mechanisms that exist today," Nickell said of the large-load proposal. "We think it makes sense for you all to understand how it can be incorporated within the current cost-allocation concepts because it may be that you all want to do something different, and we need to hear that. We need to know that."

More than 30 staffers are working on the effort to quickly add large loads, Nickell said. He said SPP has scouted how others in the industry are handling the problem, noting Southern Co.'s 90-day study process.

"We need to be able to match or meet that, so that's the goal," he said. "The goal is to try to be the best and make sure that we're helping our states and helping our utilities kind of be that service provider of choice. We're feeling the heat to move faster."

To that end, SPP is working to streamline the cumbersome stakeholder process. Staff plan to bring suggestions for streamlining the process to the Corporate Governance Committee in August.

"We'll start socializing those there, and then, of course, we'll see what we come up with," Nickell said.

He cited the recent approval of an expedited resource adequacy study (ERAS) as an example of quickly moving a tariff revision through the various working groups and committees. ERAS, designed to help load-responsible entities meet their resource adequacy requirements that are under pressure from large loads and SPP's backlogged generator interconnection queue, was readied for a FERC filing in about nine months. (See *SPP Board OKs 1-time Study for LREs' Gen Needs*.)

"So that's about as fast as we've ever done anything," Nickell said.

He said SPP faces the need to move "even faster" and to do so in a manner that results in successful FERC filings. Commission filings need to be supported by a majority of members, he said.

"We have to make sure that we continue to offer a stakeholder process that allows people to provide their input and their voice," Nickell said.

He pointed to the demand response project as another example of the need for speed. Under its original plan, the project was scheduled to be completed in the first part of 2026. It now is being moved to the October-November series of governance meetings.

At the same time, SPP has begun an awareness campaign for *Surplus Plus*, a suite of initiatives aligning with its corporate goals to accelerate the addition of new generation. The key initiative is priority processing, intended to add incremental capacity quickly at existing facilities, limited to shovel-ready projects. The grid operator says this will strengthen resource adequacy, expedite projects with limited impact, use existing infrastructure efficiently and reduce the impact to the GI queue.

The RTO held a separate education session June 13 on Surplus Plus projects during the afternoon after Nickell's comments to the RSC. Like ERAS, Surplus Plus was recommended by the Resource Energy and Adequacy Leadership Team, which has been working quietly in the background since 2023.

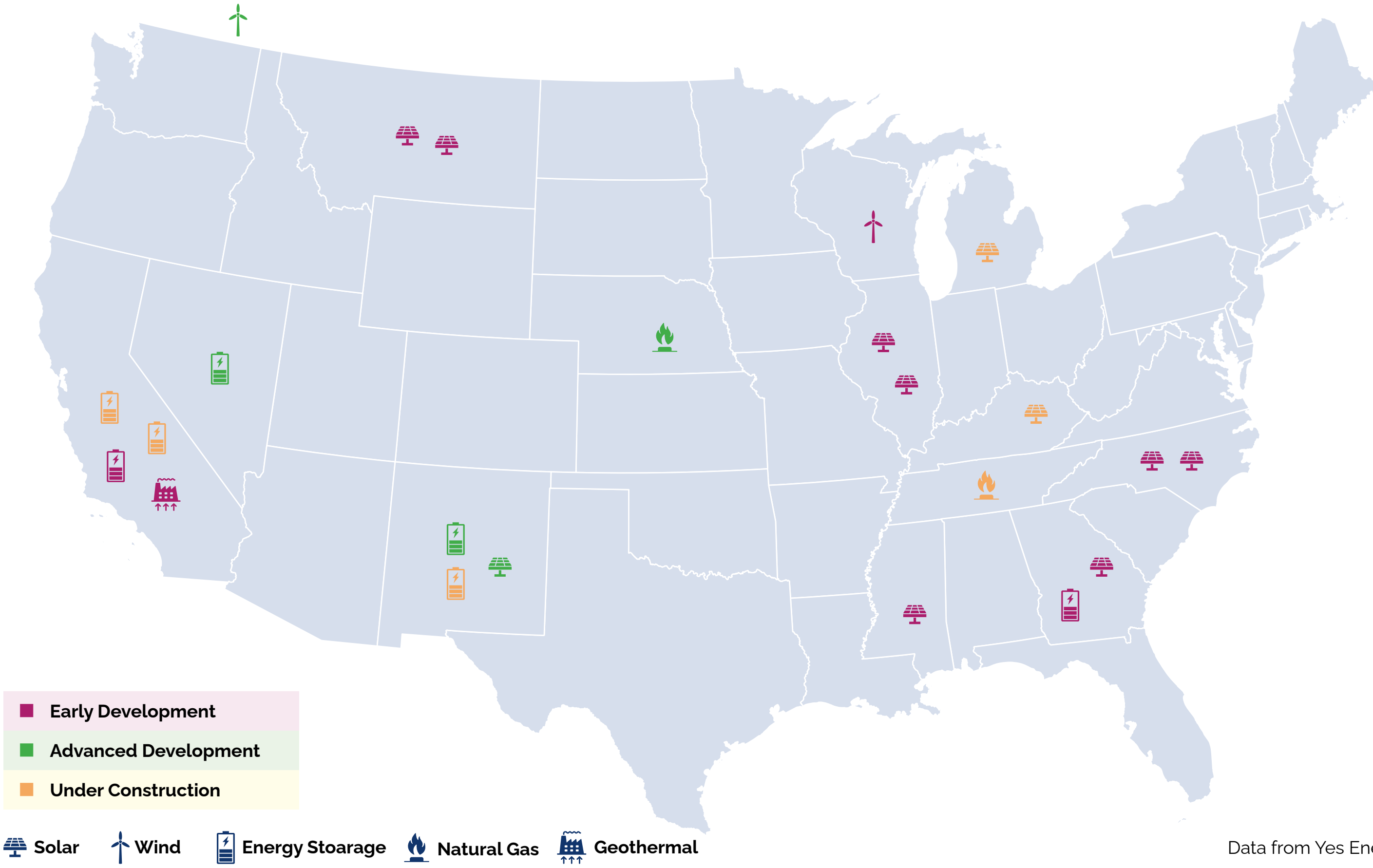
The education sessions continue. The Markets and Operations Policy Committee is meeting virtually June 26 and again June 30 to consider a tariff change to improve the GI study process by introducing a more realistic validation step to reduce the "over-mitigation of group-wide transmission constraints."

The expedited approval will allow SPP to conclude a 2023 study phase before the July MOPC meeting.

Revolutionary, not evolutionary. ■

Generation Projects Added in the Past Week

YES ENERGY



Data from Yes Energy

Project or Unit Name	Holding Company or Parent Organization	Primary Energy Source	State or Province	Capacity (MW)	In Service Year
Nithi Mountain Wind (Ni Ti)	Stellat'en First Nation	Wind	BC	200	2029
Foxtrot Solar (MO)	Invenergy	Solar	MO	107	2026
Roccaseca Energy Storage	Eolus Vind AB	Energy Storage	NV	126	2026
Compass Energy Storage	Engie SA	Energy Storage	CA	250	2026
Callaway Solar	Ameren	Solar	MO		2100
Project Phoenix Solar	Tennessee Valley Authority	Solar	KY	100	2028
Turtle Creek Station Unit 3	Omaha Public Power District	Natural Gas	NE	264	2028
Amedee Geothermal Venture I NEW	Ownership Undisclosed	Geothermal	CA	1	2027
Star Light Energy Center (Starlight)	NextEra Energy, Inc.	Solar	NM	100	2026
Star Light Energy Center (Starlight) BESS	NextEra Energy	Energy Storage	NM	100	2026
Hub City Wind	Alliant Energy	Wind	WI	100	2100
Suter Solar	EQT Partners	Solar	IL	5	2100
Gratiot Solar Park	DTE Energy	Solar	MI	50	2026
Pepper Hammock BESS	BrightNight	Energy Storage	GA	400	2028
Pepper Hammock Solar 1	BrightNight	Solar	GA	1,200	2027
CalPeak Power Border BESS	Avenue Capital Group	Energy Storage	CA	54	2025
Hudson Twp III Solar (Hudson III)	6GM LLC	Solar	IL	5	2100
Kingston Natural Gas Repowering CC	Tennessee Valley Authority	Natural Gas	TN	750	2027
Okolona Solar	NextEra Energy	Solar	MS	145	2027
Santa Teresa Solar BESS	InfraRed Capital Partners	Energy Storage	NM	150	2026
Timber Mill Solar	Cypress Creek Renewables	Solar	NC	80	2028
Timber Mill Solar BESS	Cypress Creek Renewables	Solar	NC	32	2028
Edwards Sanborn Solar 1C	Axium Infrastructure Inc.	Solar	CA	46	2025

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Company Briefs

Venture Global Withdraws Application for Delta LNG Project

Venture Global last week withdrew its application with FERC to build the Delta LNG export facility in Louisiana.

The company said it will instead concentrate on the Plaquemines expansion project, as the Delta LNG project would not be the most efficient use of its resources.

More: *Offshore Technology*

Amazon to Spend $20B on Data Centers in Pa.

Amazon last week announced it will spend $20 billion on two data center complexes in Pennsylvania, including one it is building alongside a nuclear power plant.

One data center will be next to the Susquehanna nuclear power plant, where it intends to get its power. The other will be in Fairless Hills at a logistics campus, the Keystone Trade Center, on what was once a U.S. Steel mill.

More: *The Associated Press*

Battery Storage Firm Powin Files for Bankruptcy

Energy storage provider Powin last week filed for Chapter 11 bankruptcy relief in New Jersey after registering at least $300 million in debt obligations.

The company, which has been struggling under import tariffs and uncertainties surrounding the Investment Tax Credit, has between 1,000 and 5,000 creditors with estimated liabilities and assets of between $100 million and $500 million., according to court documents.

More: *Renewables Now*

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Federal Briefs

Trump Fires Geer from TVA Board, Hanson from NRC

President Donald Trump last week fired Biden appointees Beth Geer from the Tennessee Valley Authority Board of Directors and Commissioner Christopher Hanson from the Nuclear Regulatory Commission.

Geer was one of six people nominated to the board by then-President Joe Biden in 2023. Trump has also fired Biden appointee Michelle Moore in March and Chair Joe Ritch on April 1. Geer's term was set to expire in May 2026.

White House Spokesperson Anna Kelly said Trump "reserves the right to remove employees within his own Executive Branch who exert his executive authority," in relation to Hanson's removal. Hanson was tapped to be NRC chair by former President Biden in 2021. He was later replaced when Trump selected then-Commissioner David Wright to serve as chair under the new administration.

More: *Knoxville News Sentinel*; *POLITICO*

World Bank Ends Ban on Nuclear Funding

The World Bank last week announced it was lifting its longstanding ban on funding nuclear power projects.

The ban has been in place since 2013, but the last time the bank funded a nuclear power project was 1959. In the decades since, some of the bank's major funders have opposed involvement in nuclear energy due to the possibility of catastrophic accidents in poor countries. However, more than 20 countries signed a pledge to triple nuclear power by 2050 at the United Nations' climate conference two years ago.

Bank President Ajay Banga also raised the possibility on lifting its ban funding oil and gas drilling, but no agreement had been reached.

More: *The New York Times*

EIA: US Natural Gas Storage Capacity Increased in 2024

Underground working natural gas storage capacity in the lower 48 states increased in 2024, according to the Energy Information Administration's latest data.

In 2024, demonstrated peak capacity rose 1.7%, or 70 billion cubic feet (Bcf), to 4,277 Bcf. Meanwhile, working gas design capacity increased slightly by 0.1%, or 3 Bcf.

Demonstrated peak capacity increased in four of the five regions in the lower 48, which reflected both greater use of existing facilities and expansions of infrastructure. The largest increase in demonstrated peak capacity was in the Mountain region, where colder-than-normal temperatures during the winter required more working gas in storage to meet demand.

More: *EIA*

Mid-Atlantic news from our other channels

N.J. Gubernatorial Picks Differ Sharply over Energy

NetZero Insider

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

State Briefs

COLORADO

Montrose County Continues Moratorium on Large-scale Solar

Montrose County's board of commissioners voted not to lift the moratorium on large-scale solar projects that has been in place for the past two years.

The board plans to collect more public feedback this summer and will consider the issue again in August.

More: *KAJX*

FLORIDA

FPL Plans Solar Project on Former Citrus Land

Florida Power & Light last week presented the Indian River County Technical Review Committee with plans for a 75-MW solar farm on former citrus land.

The Vernia Solar Energy Center would sit on 449 acres and would be the utility's fifth facility in the county.

Construction is planned for late 2026 and would finish in the fall of 2027.

More: *Treasure Coast Newspapers*

GEORGIA

Judge Disqualifies Blackman from PSC Primary

Fulton County Superior Court Judge **Ural Glanville** last week disqualified Daniel Blackman from the Public Service Commission primary elections on June 17.

Glanville ruled that Blackman hadn't proved he had lived in Fulton County for the required year before the general election in November. Blackman can appeal, but if he loses, any votes cast for him will not be counted.

Blackman said he moved from Forsyth County to a southwest Atlanta apartment in October 2024. But Glanville said Blackman didn't do enough to prove he had truly moved, noting he didn't transfer his voter registration to Fulton County until April.

More: *The Associated Press*

ILLINOIS

Madigan Sentenced to 7.5 Years in Prison for Bribery, Corruption

Former House Speaker Michael Madigan last week was sentenced to 90 months, or 7 ½ years, in federal prison after being convicted on 10 of 23 corruption charges, including bribery.

The sentence, which also includes three years' probation after his prison term and a $2.5 million fine, follows a jury's split verdict in February.

Madigan was ordered to report to a yet-to-be-named federal prison on Oct. 13.

More: *Capitol News Illinois*

IOWA

Reynolds Vetoes Bill Restricting Pipelines' Use of Eminent Domain

Gov. **Kim Reynolds** last week vetoed a bill pertaining to eminent domain and carbon sequestration pipelines.

The bill would have increased insurance requirements for hazardous liquid pipelines, limited carbon pipeline permits to one 25-year term and changed the definition of a common carrier for pipelines, making it more difficult for the projects to use eminent domain.

Reynolds said she shared the bill's goal of "protecting landowners" but the bill lacked the "clear, careful lines" drawn in good policy.

More: *Iowa Capital Dispatch*

MINNESOTA

Legislature Approves Increased EV Fee

The state Legislature last week voted to increase fees for EV owners.

The current $75 annual fee will double to at least $150. How much someone pays could be steeper if they have a more expensive, newer vehicle, similar to how the state calculates registration fees, which EV owners must still pay.

The new surcharge will go into effect after Jan. 1.

More: *WCCO*

NEW YORK

RG&E, NYSEG Fined $20M for Failing Customer Service Metrics

The Public Service Commission last week announced that RG&E and NYSEG were fined for failing to meet 2024 customer service standards.

NYSEG was fined $11.2 million, while Rochester Gas & Electric was fined $9.8 million.

More: *WROC*

OHIO

OPSB Approves Construction of Gas Plant

The Power Siting Board last week approved the construction of the Socrates South Power Generation Project.

The $1.6 billion, 200-MW natural gas plant will provide behind-the-meter power to a Meta data center.

Construction is slated to begin in the third quarter of this year, with an estimated completion date of 2026.

More: *Data Center Dynamics*

OREGON

Power Shutoffs Banned During Extreme Summer Heat

The Public Utility Commission last week approved temporary rules to protect low-income residential customers from power disconnections during high summer heat.

Under the rules, all investor-owned electric utilities are prohibited from disconnecting service due to non-payment during major heat waves.

The ban starts this month and runs through October.

More: *The Oregonian*