ISSN 2377-8016 : Volume 2025/Issue 19 ▪ May 13, 2025

YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

CAISO/WEST

BPA Chooses Markets+ over EDAM

Travel Portland

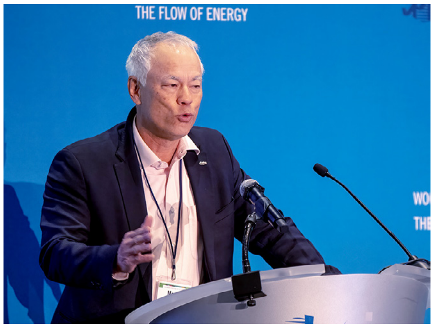
BPA's decision to join Markets+ likely was vital to the viability of the SPP market and could influence other Northwest entities to commit as well.

CONTINUED ON P.8

Panel Explores How Western Markets Have 'Played off' Each Other *(p.9)*

Puget Sound Energy Inks Agreement to Join Markets+ *(p.11)*

PJM



© RTO Insider

PJM Stakeholders Vote Out 2 Board Members (p.28)

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

PJM OC Briefs *(p.30)*

FERC/FEDERAL

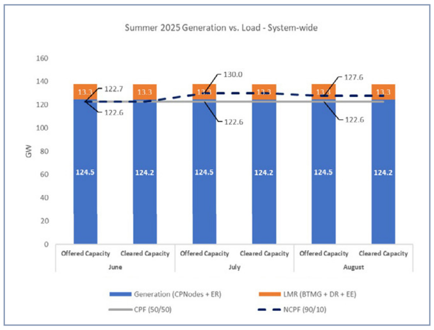
Shutterstock

Budget Bills Would End Energy Tax Credits Early, Claw Back Other Funding (p.5)

The bills would give generation developers a few more years of the production tax credit and investment tax credit before they are wound down starting in 2029, while also speeding up permitting and limiting the judicial review of natural gas infrastructure.

Wright Defends DOE Budget at House Appropriations Subcommittee *(p.7)*

MISO



MISO

MISO Prepping for Likely 123-GW Summer 2025 Peak (p.20)

MISO said summer is it's likely going to be hot and dry, which could drive load past record levels.

Stakeholders Ask FERC to Soften MISO's Proposed DR Accreditation *(p.22)*

RTO Insider
2415 Boston St.
Baltimore, MD 21224
(301) 658-6885

In this week's issue

Editor's Choice

Spain Outage; Texas Legislature; and Other Timely Opinion . . . 3

Stakeholder Soapbox

The Unseen Costs of Subsidized Solar . . . 4

FERC/Federal

Budget Bills Would End Energy Tax Credits Early, Claw Back Other Funding . . . 5
Wright Defends DOE Budget at House Appropriations Subcommittee . . . 7

CAISO/West

BPA Chooses Markets+ over EDAM . . . 8
Puget Sound Energy Inks Agreement to Join Markets+ . . . 11
CEC Approves 3 IRPs, Decreases Battery Storage Project Size . . . 12
Panel Explores How Western Markets Have 'Played off' Each Other . . . 13
BPA's Tx Planning Pause Prompts Talk of New RTO, Stricter TSR Requirements . . . 14
California Will Rely Heavily on Batteries to Meet Summer 2025 Peaks . . . 15
New Colo. Law to Streamline Siting of Tx Lines Along Highways . . . 17

ISO-NE

ISO-NE Discusses Details of New Prompt Capacity Market . . . 18

MISO

MISO Prepping for Likely 123-GW Summer 2025 Peak . . . 20
Stakeholders Ask FERC to Soften MISO's Proposed DR Accreditation . . . 22
MISO's AC Rekindles Talk on Gas-electric Coordination Frustrations . . . 24

NYISO

NYISO to Include Empire Wind in Q2 STAR Base Case . . . 25
NYISO Monitor Analyzing Alternative Capacity Market Designs . . . 26
NYPA Hedges on NYC Peaker Plant Retirements . . . 27

PJM

PJM Stakeholders Vote Out 2 Board Members . . . 28
PJM OC Briefs . . . 30
DOJ Seeks PJM Market Data for Review of Constellation-Calpine Merger . . . 31
PJM MIC Briefs . . . 32
PJM PC/TEAC Briefs . . . 33

SPP

SPP Approves 6th Competitive Transmission Project . . . 35
SPP Board OKs 1-time Study for LREs' Gen Needs . . . 37

Company News

Duke Earnings Report Highlights Huge Investments to Meet Load Growth . . . 40
AEP to Meet Load Growth with More Infrastructure . . . 41
As it Pursues Deals, Constellation Says Data Center Load Growth Overstated . . . 42
NRG to Buy 13 GW of Generation Capacity from LS Power . . . 44

Briefs

Company Briefs . . . 45
Federal Briefs . . . 45
State Briefs . . . 46

Spain Outage; Texas Legislature; and Other Timely Opinion

By Ken Sands


Ken Sands

Editor's Choice is a curation of timely opinion writing on energy and the electric grid. Here's some of what we found interesting this week:

The April 28 blackout in Spain is a clear warning that pushing the grid toward 100% inverter-based resources can lead to a grid that is vulnerable to major blackouts, writes energy analyst and author *Meredith Angwin*.

On her Substack, "The Electric Grandma," Angwin wrote: "The Iberian grid was depending heavily on solar, and the solar was depending heavily on switches. The switches have a fancy name (inverters), but at the core, they are still switches. Thermal (gas, coal, nuclear) power plants and hydro plants run on a different system: They have huge spinning generators, not inverters. The generators are big; they are spinning; and they want to keep spinning. They have inertia."

(For more context, see CNBC coverage: *"Spain's Unprecedented Power Outage Sparks a Blackout Blame Game over Green Energy."*)

Angwin likens the Spanish outage to the Odessa incidents in Texas in 2021 and 2022. "During the first one, in May 2021, a surge arrestor tripped at a combined cycle power plant, and the power plant (192 MW) went offline. Quickly following the power plant going offline, 1,100 MW of [inverter-based] wind and solar went offline."

She continues: "How does the Texas situation compare to the situation in Spain? In Spain, total power was supposed to be about 25,000 MW online. At the time of the blackout in Spain, wind and solar PV (IBRs) provided 72% of the power, and synchronous plants provided 28%.

"In other words, Spain had too many IBRs (switches) and not enough traditional (spinning) generation."

Texas Heat and Legislative Priorities

Doug Lewin, president of Stoic Energy and host of the Energy Capital podcast, writes frequently about the Texas Legislature's activities in "*The Texas Energy and Power Newsletter*" on Substack.

Writing May 12, he says ERCOT is forecasting a peak of over 84 GW, "which would shatter the previous May record of 77 GW and even threaten the all-time demand record. ERCOT expects plenty of extra capacity despite large thermal power plant outages; solar power is expected to deliver well over 20 GW.

"Even at peak, ERCOT expects outages to remain above 16,000 MW. These kinds of spring heat waves are becoming more common, and renewables and storage are a major part of preventing outages."

However, bills advancing in the Legislature to promote fossil fuels and discourage renewables could make a huge difference, he maintains. "Should various anti-energy bills (SB 715/HB 3356, SB 388, SB 819) become law, these kinds of events would almost certainly create energy emergencies."

He writes: "The idea among some policymakers and advocates that you can run the whole system on thermal power plants and reduce the risk of outages ignores the reality that there were outages in 2006 and 2011 before renewables were very significant."

Solar energy naturally peaks during a heat wave when air conditioning is needed most.

"Solar output is expected to be over 21 GW at the time the peak is reached. There is only a small chance of a conservation call, much less an energy emergency, despite the high levels of thermal outages so late in the outage season.

"Grids are *systems*, and renewables and gas strengthen each other and help us avoid emergencies."

Large Power Transformers and Tariffs

The Trump administration and China *seem to have entered* a (temporary, at least) truce in the ongoing trade war over tariffs.

Why This Matters

Analyst Meredith Angwin warns that 'if a push for 'all renewables' continues to shut down spinning generators, we would only have power plants with switches. We need some power plants with inertia. Or we could end up imitating Spain.'

Another Substack writer, Mary Geddry, *draws attention* to the importance to the grid of large power transformers, and how they are mostly produced overseas. "America's electric grid may be one weather event or rifle shot away from catastrophe.

"These behemoths, up to 800,000 pounds each, are essential to high-voltage transmission. Only about 20% of the United States' transformer needs are met domestically."

She continues: "And if a Carrington-class solar flare or coordinated sabotage event hit the grid, there is no strategic reserve of spares. The result would not be a power outage. It would be a systemic collapse."

She describes a close call: "In 2013, a few small-caliber bullets fired at a California substation nearly triggered a blackout across the Western U.S. That wasn't a fluke. It was a warning.

"A single point of failure in the grid, like the destruction of a high-voltage transformer, can ripple outward, tripping automatic shutdowns and overloading parallel systems in a cascading domino effect. Hospitals, data centers, emergency services and water treatment plants can go offline. Traffic grinds to a halt. Supply chains stall. Even brief outages can result in billions in losses." ■

If you have opinions you would like to share, follow the Stakeholder Soapbox guidelines.

The Unseen Costs of Subsidized Solar

A Looming Risk for America's Power Grids

By Doug Sheridan

Doug Sheridan

Policymakers and advocates often hail solar energy as the future of electricity generation. Yet behind the glowing headlines and government incentives lies an overlooked economic risk — one that threatens both grid stability and long-term affordability.

If one were to assess solar power's true cost, a simple thought experiment proves instructive. Imagine a U.S. region rich in both natural gas and sunlight, where a hypothetical grid relies entirely on newly built generation. Based on 2024 gas prices and capital costs, at a baseline, a 100% gas-fired system would break even at approximately $50 to $55/MWh.

However, as solar capacity is added, the system's breakeven cost of generation rises by $3.25–$3.50/MWh for every 10 percentage points of demand captured by solar. At 50% solar penetration, system generation costs would rise to $65–$73/MWh. This is before considering the costs of additional large-scale battery storage, system balancing and monitoring, and transmission assets inevitably needed to make solar work well enough to achieve and maintain such a market share.

Yet the situation on today's real-world grids is even more precarious. In many cases, new solar farms are being added to systems otherwise dominated by legacy gas-fired power plants. These assets were built under the assumption they would have a fair opportunity to generate returns over their lifespan. Instead, heavily subsidized solar generation — boosted further by both national and state regulatory favoritism — is driving wholesale electricity prices down while pushing older, gas-fired plants to the financial brink.

For many power producers, this shift has created a brutal economic reality — legacy gas-fired plants being forced into an uneconomical position, unable to justify reinvestment or sustain profitability. This dynamic keeps power prices artificially low in the short term but lays the groundwork for rising costs over time — as dispatchable gas-fired units retire and grids become dangerously reliant on intermittent solar.

No grid exemplifies this trend more starkly than ERCOT, which supplies power to millions of people across the state. Rapidly growing solar penetration has eroded developer confidence in the profitability of gas-fired projects on the system — as evidenced by the lukewarm enthusiasm for the $5 billion Texas Energy Fund designed to incentivize new gas-fired capacity. (See *2 More Projects Fall out of TEF Loan Program*.) Developers continue to refuse its offers, no doubt concerned over the lack of regulatory and economic safeguards against the eroding effects of subsidized renewables.

Why This Matters

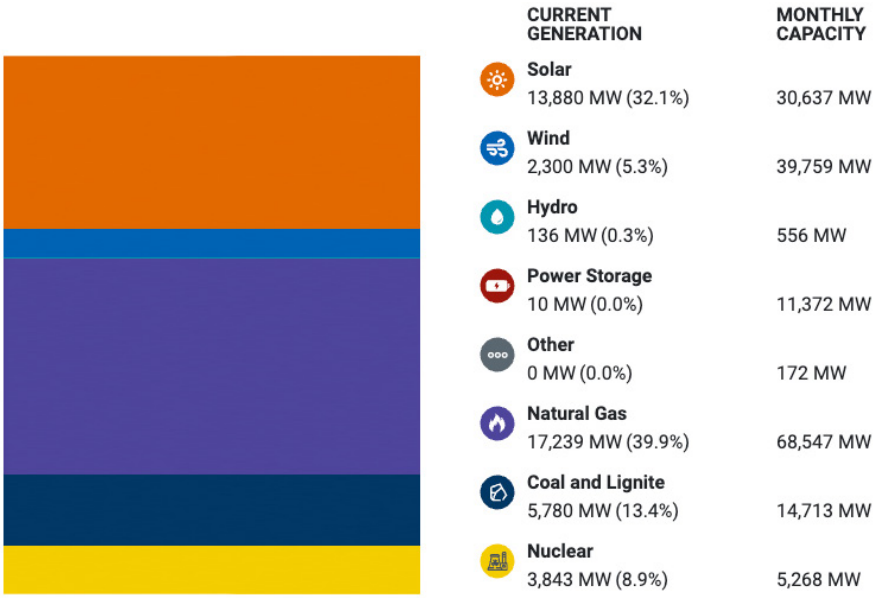
Energy analyst Doug Sheridan says that without course correction, states like Texas risk facing an electricity crisis not in spite of solar's success—but because of it.

Texas is at an inflection point. The systematic erosion of its time-tested dispatchable gas-fired generation threatens grid reliability, while the economic uncertainty deters investors from stepping in to stabilize the system.

If history is any indication, officials may attempt to downplay the consequences of solar's effects on the system or blame external factors like rising demand. But in reality, Texas — and states following similar paths — are setting themselves up for long-term risks in both pricing and power security. The risk of higher residential rates and more frequent blackouts cannot be ignored.

Subsidized solar may look economically attractive today, but its distortive impacts on energy markets tell a different story. Without course correction, states like Texas risk facing an electricity crisis not in spite of solar's success — but because of it. ■

Doug Sheridan is president of EnergyPoint Research in Houston.



ERCOT real time fuel mix | *ERCOT*

See Stakeholder Soapbox guidelines to learn how to make a submission for publication.

Budget Bills Would End Energy Tax Credits Early, Claw Back Other Funding

By James Downing

Key House committees are marking up "One Big, Beautiful Bill" for the fiscal 2025 budget that includes much of President Donald Trump's legislative goals, including clawing back funds and phasing out tax credits for clean energy.

The House Ways and Means Committee on May 12 released proposed *language* that would axe the tax credits for energy-efficient and plug-in vehicles while winding down credits for renewable and nuclear energy earlier than current law.

The production tax credit (PTC) and investment tax credit (ITC) for wind and solar are currently in place until the later of 2033 or when CO_2 emissions fall below 25% of 2022 levels. Under the bill, both would start to be rolled back in 2029. Projects put into service by Dec. 31, 2028, will be eligible for the full rates, but that will be cut back to 80% in 2029, 60% in 2030, 40% in 2031 and then expire entirely for 2032.

American Clean Power Association CEO Jason Grumet criticized the early phaseout as causing disruption when the industry needs to meet surging demand. He promised to work with Congress to improve the language as the bill moves forward.

"The Ways and Means bill is at odds with American energy dominance," Grumet said in a statement. "If adopted, the proposed language will raise energy costs for American consumers, force American factories to shut their doors and threaten American jobs. While our industry is ready to engage constructively and find a workable path forward, the committee's approach simply goes too far too fast."

Shutterstock

Why This Matters

The bills would give generation developers a few more years of the production tax credit and investment tax credit before they are wound down starting in 2029, while also speeding up permitting and limiting the judicial review of natural gas infrastructure.

Even without subsidies, some wind and solar would have been built, but the tax credits have expanded their capacity on the grid well beyond that hypothetical, American Enterprise Institute's James Coleman said at a panel on Capitol Hill on May 6 hosted by the Electric Power Supply Association. The tax credits do not need to go to zero tomorrow, which would upset business plans, he said.

"But I do think it's a problem that needs to be phased out, addressed, lowered — something needs to be done there," Coleman said.

The 45U PTC for existing nuclear also would be wound down earlier, following the same schedule as the other tax credits.

Provisions in the bill would also end the transferability for tax credits, which allows energy producers to sell them to third parties.

Speaking to analysts on an earnings call May 6, Duke Energy CEO Harry Sideris said the nuclear tax credits were most important to the utility. (See *Duke Earnings Report Highlights Huge Investments to Meet Load Growth*.)

"Our well-run, low-cost nuclear plants earn over $500 billion in tax credits that go directly to reducing our customers' bills," Sideris said. "Nuclear has broad support in Washington, and we were pleased to see last week [that] 26 representatives signed a *letter* stressing the importance of these nuclear tax credits and transferability to the president's objective of affordable and reliable energy."

The Natural Resources Defense Council criticized the bill after the text was made public.

"This measure would hike energy bills, not lower them; cut domestic energy production, not increase it; and put workers out of jobs, not spur American manufacturing," said Jackie Wong, NRDC senior vice president for climate and energy.

The bill would immediately end energy efficiency tax credits, including the Energy Efficient Home Improvement (25C) credit and the New Energy Efficient Home (45L) credit. It would also end credits for individual consumers to buy new (30D) and used (25E) electric vehicles and the Commercial Clean Vehicle credit (45W).

"Canceling these tax credits would raise monthly costs for American families and businesses," American Council for an Energy Efficient Economy Executive Director Steven Nadel said in a statement. "This proposal would make it harder for homeowners to make energy improvements that lower their utility bills and improve their comfort. It would reduce builders' incentive to construct efficient homes with low monthly energy bills. It would make it harder for individuals to use electric cars and businesses to use electric trucks, which can both lower monthly costs."

House Energy and Commerce's Markup

The Energy and Commerce Committee also released *language* that includes clawing back some unspent funds from the Inflation Reduction Act and provisions meant to speed up permitting of natural gas infrastructure and electric transmission.

"This bill would claw back money headed for green boondoggles through 'environmental and climate justice block grants' and other spending mechanisms through the Environmental Protection Agency and Energy Department," committee Chair Brett Guthrie (R-Ky.) wrote in an *op-ed* published by *The Wall Street Journal*. "The legislation would reverse the most reckless parts of the engorged climate spending in the misnamed Inflation Reduction Act, returning $6.5 billion in unspent funds."

Those clawbacks would include funding for transmission, facilitation of the siting of interstate lines, and interregional and offshore wind electricity transmission planning.

Language from Rep. Julie Fedorchak (R-N.D.) is meant to speed up cross-border pipelines and transmission. It would remove the process from the State Department and the White House and give FERC authority over siting pipelines and DOE over transmission, limiting the president's power to overturn their decisions.

"We need a cross-border permitting process that supports investment and infrastructure — one that can't be undone by the stroke of a pen," Fedorchak said. "North Dakota has long worked with Canada to develop and transport reliable energy, and this bill strengthens that partnership while ensuring the U.S. remains a leader in energy production. This legislation gives energy producers the green light to move forward with certainty and will help us deliver reliable, affordable energy to American families, farmers and businesses who depend on it every day."

The bill would allow pipeline developers to speed up their review process before all federal agencies by notifying FERC in their application and paying the U.S. Treasury the lesser of $10 million or 1% of the total project cost. The approvals would have to be completed within a year, with agencies able to ask FERC for an additional six months "if the commission receives consent from the relevant applicant."

Developers of LNG export and import facilities would have to pay $1 million in a fee collected by the secretary of energy, who would then be required to find the application in the public intertest.

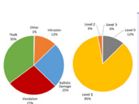
Other language in the bill would clear up a longstanding issue, giving FERC jurisdiction over interstate pipelines meant to carry carbon dioxide and hydrogen.

The bill would also limit who can sue for judicial review of natural gas permits, the NRDC said in a statement.

"While it slashes much-needed support for clean energy and climate resilience, it would allow fossil fuel companies to pay to get their project approved," NRDC Chief Policy Advocacy Officer Alexandra Adams said in a statement. "That's not just wrong; it's un-American. Congress should reject this radical bill that would harm the health and welfare of the American people." ■

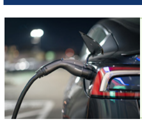
National/Federal news from our other channels

NERC Offered to Help with Iberia Outage Investigation, Robb Says — ERO Insider



E-ISAC Reports on Cyber, Physical Threats — ERO Insider

West news from our other channels



California, Other States Sue Trump Administration over Halting EV Charger Funds — NetZero Insider

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

Wright Defends DOE Budget at House Appropriations Subcommittee

By James Downing


Energy Secretary Chris Wright at his Senate confirmation hearing in January | *Senate Energy and Natural Resources Committee*

Energy Secretary Chris Wright testified on the Trump administration's budget request for his department before a House Appropriations subcommittee hearing in which many of the questions were focused on funds already authorized by Congress that his department has delayed.

Why This Matters

Energy Secretary Chris Wright spent much of a budget hearing defending his department's review of previously authorized spending, which Democrats said has upset projects around the country.

"This budget will return DOE to its core mission of advancing energy innovation and global competitiveness through research and development," Wright told the Subcommittee on Energy and Water Development on May 7. "We will invest DOE's resources in sources and technologies that support affordable, reliable and secure energy and provide a return on investment for the American taxpayers."

The hearing was scheduled at the same time as other Appropriations subcommittees were reviewing budgets for the departments of Agriculture, the Army, the Treasury and Homeland Security. That schedule led to complaints from Ranking Member Marcy Kaptur (D-Ohio).

"We're being squished into this tourniquet, and it's not fair to you, and it's not fair to the American people, and it's not fair to members," Kaptur said. "And I know this chairman didn't do it, but I don't like it because we can't get into the level of detail that we need to do. And it's all part of this squeeze by the new administration."

In addition to complaining about the Republican majority's review of the budget, she also criticized the proposed $20 billion in cuts to DOE's budget, including 74% of the funding for energy efficiency and renewable energy.

"Since January, the Department of Energy has suspended critical energy programs, canceled executed awards and contracts authorized by this Congress, severely reduced staffing — including removal of the inspector general who tries to go after the crooks — and changed contracting policies," Kaptur said. "The resulting confusion has disrupted communities, businesses and project developers across our country."

At her time for questioning, Kaptur asked Wright why he had not responded to letters she and colleagues have sent to him this year asking about reports on paused congressionally approved funding.

"I receive dozens of letters accusing me of things that are reported in headlines, in blog posts and media all over the place, almost all of which are false," Wright said. "Everyone who's reached directly out to me, I've jumped on the phone with."

Wright said his department has not paused funding because any project that was already underway has not seen its funding impacted, but it is reviewing other projects that were not underway. Part of that review includes $100 billion in loan commitments the Biden administration pushed out between the 2024 presidential election and President Donald Trump's inauguration, Wright said.

Rep. Rosa DeLauro (D-Conn.), the ranking member of the Appropriations Committee, said Congress was supposed to receive a detailed spending plan for this fiscal year by the end of April, which did not happen.

"I've got a fear that we're going to lawlessly, illegally try to move these funds and move them elsewhere," DeLauro said. "But the law of the land is the 2024 enacted budget applied to 2025, so, really we're going to press on getting that."

She added that the department has refused to release $67 billion in funding. Wright took issue with her characterization of the issue and, in response to a later question, explained what is going on with that money.

"I'm very cautious about giving answers when I don't really have an answer," Wright said. "I've assembled a team and a process that's not political, that's not focused on buzzwords. It's just a technology, business and end-market overview of projects. If we invest a lot of money, we want something at the other end that's going to go forward, that's going to have customers and off-takers and move on with it."

The government spends $1.25 for every dollar in taxes it collects, Wright said, so he is on board with Trump's policies that are meant to bring that spending under control. DOE grew 20% under the Biden administration, and the request would cut its budget to the lowest level since 2017.

Rep. Dan Newhouse (R-Wash.) told Wright he was on board with the administration's goals to rein in government spending, but he pressed the secretary on staffing cuts at the Bonneville Power Administration that gets no funding from taxpayers. About 200 employees have taken buyouts offered by the Trump administration, and Newhouse worried that low staffing levels could impact the power marketing agency's operations.

Wright said he and DOE leadership are concerned about BPA and other federal power marketers' staffing levels as well, saying those 200 employees took an initial offer for early retirement and that staffing was already below target when Trump took office.

"We did a second round that's been much bigger, but we've been specific at saying we can't have people leave from Bonneville Power and the other power marketing agencies, because I don't think we have room to reduce head count there anymore," Wright said. ■

BPA Chooses Markets+ over EDAM

Decision Notches a Key Win for SPP and Sets West on Course for Divided Markets

By Robert Mullin and Henrik Nilsson

The Bonneville Power Administration on May 9 issued its long-awaited decision on joining a day-ahead market, confirming its choice of SPP's Markets+ over CAISO's Extended Day-Ahead Market, marking a major milestone for Little Rock, Ark.-based SPP's push to expand into the Western Interconnection.

BPA's final record of decision (ROD) will come as little surprise to those who've been following market developments in the West. In March, the agency released a draft "policy direction" stating that the SPP market "is the best long-term strategic direction for Bonneville, its customers and the Northwest," which followed by a year a staff "leaning" expressing similar determination. (See *BPA Selects SPP Markets+ in Draft Policy*.)

"Day-ahead market participation, specifically in Markets+, is in the best interest of our customers and the region, as it offers the opportunity to ensure a reliable, abundant and affordable energy supply for consumers in the Northwest," BPA Administrator John Hairston wrote in a *letter* announcing release of the decision.

"BPA's final policy direction toward participation in Markets+ represents significant effort by BPA staff and stakeholders to evaluate market options that support the region's ability to share affordable and reliable energy," said Carrie Simpson, SPP vice president of markets. "SPP thanks BPA for their engagement during Phase 1 of Markets+ development, and we look forward to their continued collaboration as we work together to implement a Western market that improves grid efficiency and values the needs of all participants."

The ROD represents a big win for SPP and is likely a key to the viability of Markets+, given that BPA manages the output from 31 hydroelectric dams in the Federal Columbia River Power System with a combined capacity of about 22,440 MW, while also operating more than 15,000 miles of transmission lines — about 75% of the Northwest grid.

The decision also is likely to influence the decisions of other entities in the region.

Why This Matters

BPA's decision to join Markets+ likely was vital to the viability of the SPP market and could influence other Northwest entities to commit as well.

"Puget Sound Energy appreciates BPA making the choice to participate in the Southwest Power Pool's Markets+ program," Phil Haines, the utility's director of energy supply and trading, told *RTO Insider*. "As BPA's largest transmission customer, it's important to us to have a clear view. We expect to make a decision of our own very shortly."

The ROD was the culmination of a two-year stakeholder process conducted by BPA, an effort often marked by tensions between supporters of each day-ahead market, with some EDAM backers contending the process appeared to be working to a foregone conclusion. (See *Rising Tensions Evident at BPA Day-ahead Markets Workshop*.)

The process even drew the attention of key Northwest political figures, including members of the Pacific Northwest's U.S. Senate delegation, who largely were critical of the agency's leaning in favor of the SPP market. (See *In Letter to Senators, BPA Tempers Markets+ Leaning*.)

In his letter, Hairston said the federal power agency reached its decision "through thorough policy analysis, extensive input from customers and stakeholders, careful consideration of current market dynamics, and thoughtful attention to the principles that guided our assessment."

The ROD seems to anticipate potential complaints about how BPA conducted its day-ahead markets process, saying the agency "has held one of the most open and transparent public processes to evaluate day-ahead market participation."

"In comparison, electric utilities that have indicated they will or have taken steps to join EDAM did so largely without public process or transparency. They are now rapidly implementing EDAM despite serious concerns about potential unjust and unreasonable transmission OATT terms and conditions in their BAAs," BPA wrote.

As in the "policy direction" issued in March and staff leaning published last year, BPA's ROD emphasized the importance of Markets+'s independent governance framework. While recognizing the "qualitative" nature of the issue, BPA reiterated its oft-stated opinion that the SPP market's governance structure is "superior" to that of EDAM, despite ongoing efforts by the West-Wide Governance Pathways Initiative to relax the state of California's oversight for CAISO's EDAM and Western Energy Imbalance Market (WEIM).

"Independent governance does not factor into a strict formula where the risk of negative governance-related outcomes is quantified or weighted against other criteria," BPA wrote in the ROD. "There is unmeasurable uncertainty regarding what issues will confront day-ahead markets in the future. In addition to past disputes and known current challenges, there will surely be issues that arise that no one has yet fully contemplated, and governance will surely impact market decisions that impact financial outcomes. … Bonneville would be accepting great risk if the process is biased toward certain entities, does not allow issues of concern to be prioritized or is not durable enough to provide fair representation in crisis situations."

The ROD also rebuffed requests by EDAM supporters that BPA at least delay its decision until developments play out this year related to California legislative bill that would implement the recommendations by the Pathways Initiative to bring greater independence to the EDAM and WEIM.

"Bonneville does not find merit in waiting for EDAM to incrementally improve its governance," BPA wrote. "First, Bonneville has determined that the existing Markets+ governance is superior even to the Pathways Step 2 governance revisions currently proposed for EDAM, which still require legislative approval. Second, the Pathways Step 2 governance does not sufficiently address Bonneville's concerns regarding independence and EDAM governance independence would continue to be insufficient, even under Pathways Step 2."

BPA also pointed to the "strategic benefit" of deciding on a market now, including "better coordination" with other agencies and establishing an "early seat at the table" for participating in Markets+.

'Special Problems'

In his letter, Hairston acknowledged the work that remains before BPA can begin participating in Markets+, including the agency's own "tariff and rate proceedings to determine cost allocations and the terms and conditions for transmission service."

BPA — and other Markets+ participants — also can move on to deal with the market's Phase 2 implementation stage, which begins this summer.

Participants presumably will need to begin addressing challenges stemming from the non-contiguous nature of the Markets+ footprint, which likely will consist of three isolated pockets concentrated in the Pacific Northwest, Arizona and Colorado, as well as a smaller segment in El Paso Electric's New Mexico service territory. Chief among those challenges will be the lack of transmission capacity connecting the market's zones, which will require making energy transfers through the larger EDAM, where possible.

During an April 9 meeting of CAISO's Western Energy Markets Regional Issues Forum (RIF) in Portland, Ore., Grid Strategies' Richard Doying, one of the architects of MISO's market, said the situation in the West will be unique in that the Eastern Interconnection does not contain any markets where market zones are "in their own isolated zones without physical transmission connected."

"And that is, in fact, the case for what we have right now in the Markets+ region. It's not clear, based on all of the announcements, whether EDAM will be contiguous. We have to see where everyone goes at the end of the day. … But it does introduce special problems," Doying said.

The creation of separate day-ahead markets in the West will result in more issues at the seams of the two markets,

BPA's Bonneville Dam | *Travel Portland*

although BPA and other Markets+ participants have played down the importance of seams in their market decisions.

During the April 9 RIF meeting, Todd Kochheiser, senior electrical engineer at BPA, noted the agency already manages a non-contiguous balancing authority area that spans six states and is adjacent to 18 other BAAs. He said BPA has more than 75 years of experience managing operations across seams, although he acknowledged day-ahead markets would add a new layer of complexity.

"While seams present complexities, Bonneville and other utilities have successfully managed seams in the Western Interconnection for decades," Hairston wrote. "Based on this experience, and as part of our day-ahead market implementation plan, Bonneville will reach out and collaborate with entities to mitigate seams."

Reactions

Reactions from across the region were mixed.

"We respect BPA's decision to join Markets+ and recognize the valuable contributions from diverse stakeholders across the Pacific Northwest during this evaluation process," CAISO CEO Elliot Mainzer — BPA's previous administrator — said in an email. "CAISO continues to focus on the success of the Western Energy Imbalance Market (WEIM) and the Extended Day-Ahead Market (EDAM) to ensure inclusive and efficient energy market solutions. Our commitment to maintaining reliability and delivering economic value to our customers in the West remains unwavering, and we look forward to continued collaboration with all parties involved."

"I have repeatedly stressed that BPA should take its time to get this decision right, which will impact Oregonians for decades," Sen. Jeff Merkley (D-Ore.) said in an email. "Despite concerns from my fellow senators and the governors of Oregon and Washington, BPA has made a rushed decision. BPA still needs to go through a ratemaking process, and I remain laser-focused on prioritizing the needs of Oregon families to have affordable and reliable energy."

"It's disappointing BPA has chosen this route now, when evidence suggests waiting for both day-ahead market options to mature could provide the most benefits to ratepayers," Sen. Ron Wyden (D-Ore.) said. "I'll keep pressing BPA to make decisions that prioritize affordable, reliable, and clean electricity in the Northwest."

Leah Rubin Shen, managing director at Advanced Energy United, called BPA's decision "premature," contending it could "entrench costly market seams and inefficiencies." Rubin Shen pointed to the production cost study commissioned by BPA in 2024 that showed Markets+ would deliver the agency fewer economic benefits than EDAM. (See *BPA Sticks to Markets+ Leaning Despite Study Showing EDAM Benefits*.)

"The West has the potential to come together and build a broad, unified market for the whole region," she said. "Unfortunately, this decision takes us away from that vision, cementing a narrower path that could lock us into a fragmented market structure and undermine the immense reliability and cost-savings benefits of sharing resources across the region."

"BPA's participation in Markets+ is a win for the Northwest," said Scott Simms, executive director of the Public Power Council. "This market was designed with BPA's unique role in mind, and the result reflects a strong, collaborative effort among public power, SPP, and other Western entities. We support BPA's timely decision which comes at the end of a rigorous public process. Making this decision now will allow the agency to pursue participation in a day ahead market that has the confidence of its customers."

The Northwest Energy Coalition (NWEC), a strong EDAM supporter in the region, expressed disappointment over BPA's decision and also pointed to the BPA analysis showing the greater financial benefits stemming from the larger footprint of the CAISO market.

"Yet BPA has chosen Markets+, a smaller market footprint. When BPA joins Markets+, it will decrease net benefits to customers by $108 million each year. If BPA joins EDAM, it will increase net benefits to customers by $57 million each year," NWEC wrote. "BPA's decision to pursue a market with less economic benefits for customers and less direct interconnection with other utilities across the West will reduce the potential for all electricity users in the region to benefit from a unified day-ahead market. This decision is not in the best interest of the region."

"We greatly appreciate Bonneville's continued leadership during this pivotal moment in the evolution of western energy markets," said Jeff Spires, managing director of power at Powerex. "Bonneville's choice to participate in Markets+ is the result of an extensive and comprehensive evaluation process in which Bonneville prioritized the foundational governance and market design elements that will provide benefits for Bonneville, its customers, and the broader Northwest region for years to come."

"BPA's decision to join Markets + is a significant milestone in providing confidence for other Northwest utilities to join," said Laura Trolese of The Energy Authority, chair of the Markets+ Participants Executive Committee. "I expect other announcements to follow."

Seattle City Light said it is "deeply disappointed" in the decision. "BPA's decision to join Markets+ is inconsistent with its responsibility to maximize customer benefits in accordance with sound business principles. BPA's own record and analysis shows that Markets+ will increase costs for BPA and its customers." The decision "will negatively impact the utility in two significant ways — as a market participant and as one of BPA's largest customers. Our ratepayers will bear the burden of this decision as we spend $20 [million to] $40 million more every year on energy. This is especially burdensome with the rising costs to meet growing energy needs."

"As BPA's largest individual customer, Snohomish PUD appreciates the administration's thorough and transparent evaluation of a complex decision with significant regional impact," said Adam Cornelius, power analyst at the PUD. "We expect that BPA's participation in a day-ahead market to result in more efficient usage of the Northwest's hydropower resources and transmission system, driving improved reliability and cost savings. Snohomish values the independent governance and market design of Markets+ and believes it strikes the right balance for our customers and the region."

"We continue to work collaboratively with other Markets+ members and look forward to providing APS customers more savings opportunities and continued reliable service through a larger market footprint," said Kent Walter, Arizona Public Service, director of Western market affairs. "Bonneville Power Administration joins a group of diverse utilities and generation providers who benefit from the regional diversity of the northwest and southwest participants. Together, we are developing a market structure that enables market choice for future participants." ■

Tom Kleckner contributed to this article.

Puget Sound Energy Inks Agreement to Join Markets+

Wash. Utility's Announcement Comes Just Days After BPA Chooses SPP's Day-ahead Market

By Henrik Nilsson

Puget Sound Energy said May 12 that it is joining Markets+, marking another win for SPP shortly after the Bonneville Power Administration issued its final market policy in favor of the day-ahead market.

Washington-based and investor-owned utility PSE announced in a news release that it has signed an agreement with SPP's Markets+, saying the day-ahead market's governance structure was a key factor in the decision.

The announcement comes three days after BPA issued its decision May 9 to join SPP's Markets+ instead of CAISO's Extended Day-Ahead Market. BPA's decision was perhaps unsurprising given a draft policy the federal power agency issued in March that emphasized the benefits of Markets+. (See related story *BPA Chooses Markets+ over EDAM*.)

Still, BPA's announcement in favor of Markets+ represented "a crucial development enabling PSE to fully leverage the benefits of this new market structure, given the interconnected nature of its electric transmission operations with BPA in the Pacific Northwest," PSE stated.

"As BPA's largest transmission customer, this coordination can deliver substantial operational efficiencies and cost benefits for our customers," Josh Jacobs, PSE's vice president of clean energy strategy and planning, said in a statement. "This collaborative approach allows us to actively participate in the market's development while preserving our ability to serve our customers' specific needs."

SPP has officially set Oct. 1, 2027, as the go-live date for *Markets+*, its centralized, day-ahead offering in the Western Interconnection. Between now and then, much will happen, with Sept. 1, 2025, emerging as a key date. That is the deadline for balancing authorities to join in time to be a part of the market when it goes live.

Why This Matters

After commitments by both Powerex and BPA, the Washington utility's announcement marks another victory for Markets+ in the Pacific Northwest.

Puget Sound Energy announced it would join Markets+ shortly after the Bonneville Power Administration issued its final decision to participate in the day-ahead market. | *Shutterstock*

Entities like Xcel Energy subsidiary Public Service Company of Colorado, El Paso Electric and Tacoma Power have already committed to joining SPP's day-ahead market. (See *Tacoma Power to Join SPP's Markets+*, *4 Arizona Utilities Commit to Joining Markets+* and *PSCo Seeks to Join SPP's Markets+*.)

When asked if BPA's decision could influence other entities, Carrie Simpson, SPP vice president of markets, told *RTO Insider* that BPA's policy "may support the evaluation process for other entities, which could result in others moving forward with decisions on market choice."

PSE, which has been known to lean in favor of SPP's market option, emphasized opportunities in Markets+ to expand renewable integration within the day-ahead market's geographical area.

"Additionally, the program strengthens resource adequacy through regional coordination, allowing for more efficient use of existing resources and improved reliability for customers," PSE said in the statement.

PSE also touted Markets+'s "member-driven governance structure," saying it allows the utility to "appropriately" represent its customers. The governance issue has been a significant focus for potential participants weighing whether to join Markets+ or EDAM.

BPA, like others in favor of Markets+, has often stated that the SPP market's governance structure is "superior" to that of EDAM, despite ongoing efforts by the West-Wide Governance Pathways Initiative to relax the state of California's oversight of CAISO's EDAM and Western Energy Imbalance Market (WEIM) by handing over governance to a proposed independent regional organization.

"PSE supports the incremental development of greater independence for CAISO and the West. Governance was just one factor among many that PSE considered in its market decision," Phil Haines, PSE director of energy supply and trading, told *RTO Insider*.

PSE said it "looks forward to working with SPP and other regional participants through Phase 2 development and toward market implementation." ■

CEC Approves 3 IRPs, Decreases Battery Storage Project Size

By David Krause

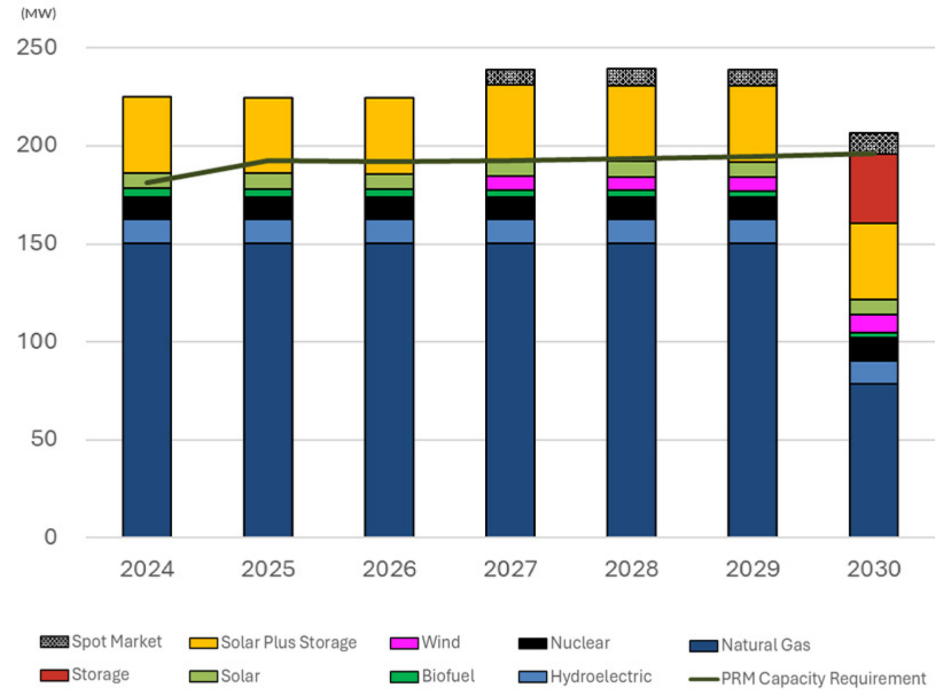
The California Energy Commission approved three integrated resource plans for publicly owned utilities as the state prepares the grid to meet peak loads this summer.

The first IRP approval went to Burbank Water and Power (BWP), which has more than 105,000 residents and is expecting electricity demand to increase in coming years due additional commercial development and electric vehicle chargers, the CEC's *report* says. BWP's peak demand is estimated to increase from 277 MW in 2023 to 323 MW in 2030 — or about 2.7% per year, CEC staff said.

From 2025 to 2027, Burbank will fall short of meeting its own capacity requirements, but it has an agreement with the Los Angeles Department of Water and Power allowing it to purchase reserve resources from LADWP. A critical project for the utility is a 3-MW solar plus storage project located at the Burbank Airport, scheduled to turn on in 2027.

The CEC also approved an IRP for Vernon Public Utilities (VPU), which has about 1,900 customers and a peak load of about 189 MW. In 2022, VPU terminated all three of its transmission contracts with Southern California Edison and LADWP, saying these contacts were not economical for its ratepayers, the CEC *report* says. VPU's peak load occurs between 10 a.m. and 2 p.m. Monday through Friday, and during these hours CAISO has recorded some of the lowest emission intensity values, including zero, as increasing amounts of solar generation are connected to the system, according to the report.

The *final IRP approval* went to Redding Electric Utility (REU), which has about 45,000 customers. REU's forecast peak demand in 2030 is 227 MW — down from 241 MW in 2018 and 253 MW in 2006. Redding utilities connect to California's transmission grid through two substation facilities owned by the Western Area Power Administration. In August 1995, REU signed a 40-year transmission agreement with WAPA. REU plans to procure 60 MW of energy from a solar project beginning in 2026.



Dependable capacity to meet peak demand | *CEC*

The commission also has amended a $30 million grant with Form Energy, reducing the grant to $25 million, decreasing the project's energy storage system size from 5 MW to 1.5 MW and increasing match share from $6 million to $25 million.

The project size was adjusted to better align with the charging capacity of the Mendocino substation, a Form Energy spokesperson told *RTO Insider*. An original study of the project indicated the site could support a discharge capacity of 5 MW and charge capacity of 4 MW, but a secondary study completed in 2024 found the interconnection charging capacity was closer to 1.5 MW on average, the spokesperson said. The project initially was estimated to come online by 2025 but now is expected to come online in 2026, the spokesperson said.

If completed, the project will be the first multiday energy storage project in California. The project grant is funded by the CEC's Long Duration Energy Storage program, which is for non-lithium technologies with more than eight hours of energy storage. ■

Panel Explores How Western Markets Have 'Played off' Each Other

Competition Between EDAM, Markets+ Topic at California Energy Summit

By Elaine Goodman

SACRAMENTO — In the competition between two Western day-ahead markets — CAISO's Extended Day Ahead Market (EDAM) and SPP's Markets+ — the two market operators have "sort of played off one another," an industry observer said.

Kris Raper, vice president of strategic engagement and external affairs at WECC, offered her views on the developing Western markets May 6 during a California Energy Transition Summit hosted by Infocast.

For a while, it seemed like CAISO's Western Energy Imbalance Market (WEIM) and EDAM "were really the only game," Raper said during a panel discussion on Western markets.

But then "SPP sort of came in the room and they had to create a space for themselves," Raper said.

"My personal observation is that SPP has sort of stood back a bit and seen within … CAISO, within the EIM and the EDAM formation, what has worked for them and what has not," Raper said. "And they have taken a script from that."

"It's a good thing, right?" she added. "If it makes them all better and utilizes more stakeholder input."

Raper's comments came in response to an audience member question on what California can learn from SPP's Western market expansion.

Another panelist, Western Freedom Executive Director Kathleen Staks, also responded.

"California has learned that … the hatred for California is real," Staks said. "That is part of why SPP saw that moment. California was not responding to the needs of the West in an adequate way."

Staks is Launch Committee co-chair for the West-Wide Governance Pathways Initiative, which is developing a new independent Western "regional organization" (RO) to oversee CAISO's WEIM and EDAM.

Kris Raper, vice president of strategic engagement and external affairs at WECC (left) and Kathleen Staks, executive director of Western Freedom. | © *RTO Insider*

Why This Matters

The competition for participants between CAISO's EDAM and SPP's Markets+ is drawing to a close as more entities in the West choose a market.

Some potential market participants are uncomfortable with markets led by CAISO, whose Board of Governors members are appointed by the California governor.

The Pathways effort now hinges on *Senate Bill 540* in the California legislature, which would allow an independent RO to oversee CAISO energy markets. (See *California Lawmakers Seek to Trump-proof Pathways Initiative Bill*.)

Affordability, Reliability

Raper described many of her comments as "personal observations" and noted that WECC has a neutral view on energy markets.

"If it adds to reliability, then that's something we would support," Raper said.

The market developments are occurring as lawmakers in several states are responding to constituent concerns by taking back power that was delegated to utility commissions, Raper said. That means a new group of stakeholders who must be educated on the issues.

"A lot of the reason that legislators are hearing from their constituents is because costs are so high," Staks said.

If SB 540 doesn't pass, Staks said, utilities that haven't yet committed to a day-ahead market may choose a non-CAISO option and leave CAISO's WEIM.

"That is not good from an affordability standpoint for California," Staks said. "It is not good from a reliability standpoint, because it makes it harder to trade with our neighbors, and it's not as good from an emissions standpoint." ■

BPA's Tx Planning Pause Prompts Talk of New RTO, Stricter TSR Requirements

Northwest Stakeholders Float Ideas to Tackle Queue

By Henrik Nilsson

Following the Bonneville Power Administration's pause on certain transmission planning processes, the agency's customers say it might be time to consider creating a regional transmission organization or imposing stricter requirements to tackle the "exponential growth" of transmission service requests.

BPA heard from several customers and industry stakeholders during a May 6 workshop, including Seattle City Light, NewSun Energy, Portland General Electric (PGE), Northwest & Intermountain Power Producers Coalition (NIPPC), Renewable Northwest, Northwest Requirements Utilities and Western Public Agencies Group.

The agency hosted the workshop after it issued a pause in February to consider new "reforms" in light of "exponential growth" of transmission service requests (TSRs). BPA's 2025 transmission cluster study includes over 65 GW of TSRs, compared with 5.9 GW in the 2021 study. The requests exceed the total regional load projected for the Pacific Northwest in 2034, according to the agency. (See *BPA Halts Some Tx Planning Processes Amid Service Requests*.)

After it issued the pause, BPA started soliciting stakeholder comments on how the agency can improve the transmission queue and deliver on its goal to go from transmission customer request to service in five to six years.

To meet that goal, BPA and power entities in the West must explore a range of possible approaches, even some controversial ones like creating an RTO, Michael Watkins, policy adviser at Seattle City Light, said during the workshop.

"Is it time for the West to finally wrap their hands around and accept that maybe we should form a regional transmission organization to bring us all together under one umbrella and actually serve our transmission needs?" Watkins said. "And it might be time to do that, and maybe it's not, but we should talk about it as part of this process. That's what we're suggesting. I know that's contentious, but I think that ought to be part of the discussion."

Watkins also said it might be time for the West to consider solutions implemented in the East, like power transfer distribution factor scheduling and compensation change.

Speaking on behalf of NIPPC, Henry Tilghman said he agrees the West should consider an RTO.

"We should also consider moving to a congestion rights or a financial transmission rights model for transmission service," Tilghman added.

Given BPA's upcoming decision on whether to join a day-ahead market, "I think considering how we can move to a congestion rights model might be something we want to put into the hopper," Tilghman said.


BPA's Bonneville Dam | *Shutterstock*

Why This Matters

BPA and the industry are considering major changes in how the Northwest transmission system should evolve to meet an increasingly complex energy landscape.

Other NIPPC recommendations include identifying reforms that don't need a tariff change, ensuring interconnection and transmission service requirements are consistent and prioritizing the transition process.

Meanwhile, Laura Green of PGE said the utility supports imposing stricter data exhibit requirements to ensure only feasible TSRs move forward and clear the queue of requests that aren't ready.

"You need to identify your [point of receipt] and your [point of delivery] and upstream generation resources, which I think we already do today. I think that's part of the requirements," Green said. "So it will be interesting to see what additional requirements might be put on customers."

Jake Stephens, CEO at NewSun Energy, said BPA should think about interim solutions and study "the lower-hanging fruit" like already planned upgrades or "simple redirects."

While BPA's efforts to address the growth of TSRs are good, the pause has impacted the market and companies that invested in resources in the belief their transmission requests would be studied, Stephens noted.

"Bonneville coming up with an interim way to keep working through that queue, I think is important," Stephens said. "I think it's necessary one way or another, because at the end of the day, if everything is studied, the results from all of that are going to be so staggering as to almost be undigestible." ■

California Will Rely Heavily on Batteries to Meet Summer 2025 Peaks

But Trump Administration Tariffs have Decreased Storage Projections for 2026

By David Krause

California's electricity grid is expected to meet peak demand this summer, with state energy officials pointing to the massive growth in solar and battery storage resources as key.

A surplus of at least 5,500 MW is projected to be available to California during peak demand under normal conditions and 1,368 MW under extreme conditions, according to a May 1 reliability *report* by the California Energy Commission, the California Public Utilities Commission and the California Air Resources Board.

As of April, more than 12,000 MW of battery storage capacity is online and serving the grid, with almost all the capacity becoming available in the past four years, CPUC staff member Christina Pelliccio said at a May 2 joint agency reliability meeting. By 2028, another 15,000 MW of storage resources are expected to be available, accounting for the majority of the 20,000 MW of new resources expected in that time.

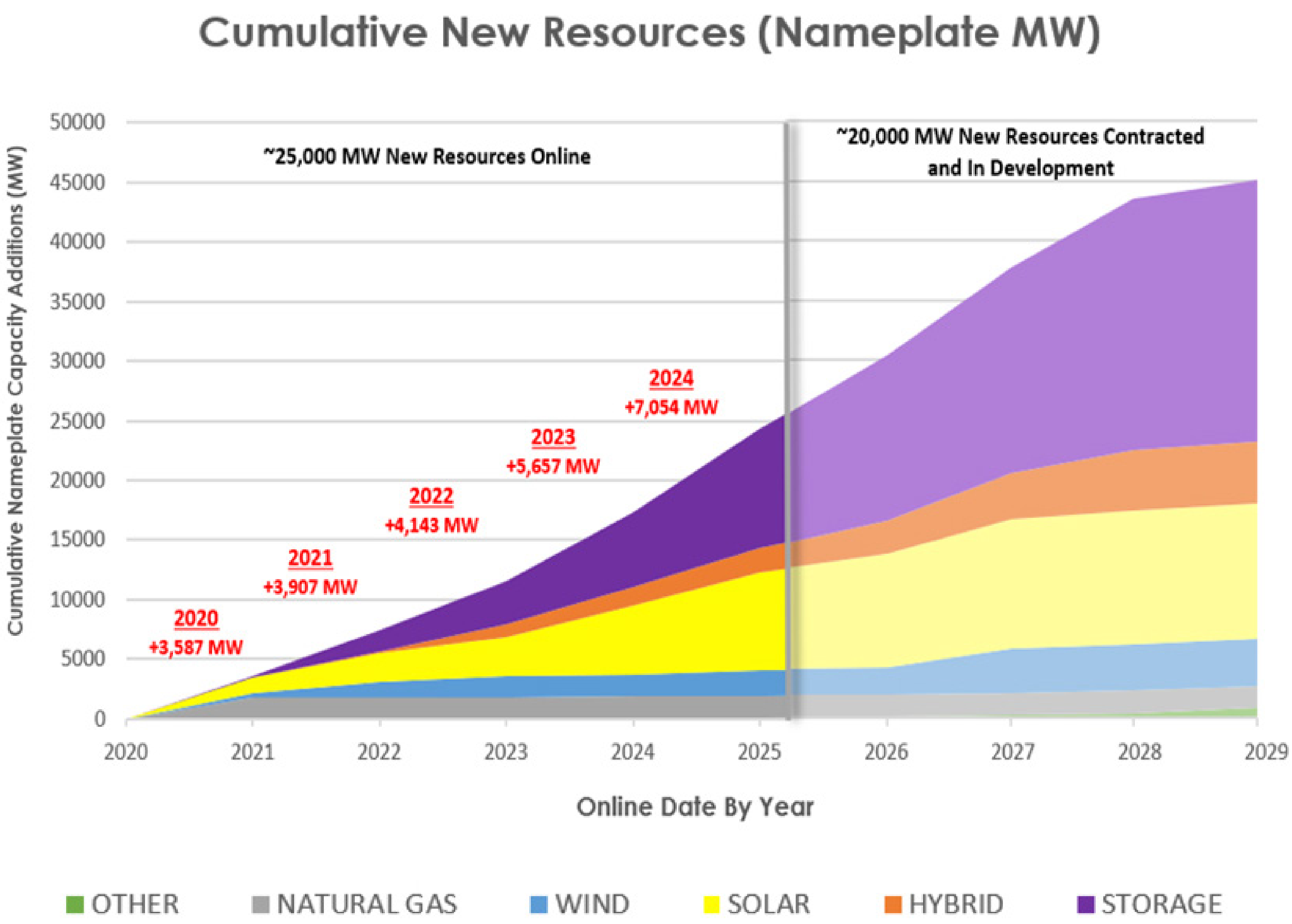
"CAISO will be able to rely on the large amounts of storage, solar and hybrid projects that are under development and projected to be online by August 2026," CPUC Senior Analyst Behdad Kiani said at the meeting.

However, storage resources are the energy technology most affected by

Why This Matters

The growing number of storage batteries on California's grid will play a key role in this summer's reliability, but the Trump administration's tariffs could reduce uptake of the increasingly vital resources next year.

Trump administration tariff changes, BloombergNEF Senior Policy Associate



Energy resource projections in the CAISO region | *CPUC*

Derrick Flakoll said. Assuming a 54% import tariff on China, battery storage additions in the U.S. in 2026 are expected to decrease from a forecast 15 GW to about 10 GW. BloombergNEF projects the cost for a four-hour battery energy storage system will increase from about $200/kWh to about $260/kWh in 2026 due to the 54% import tariff.

Even so, battery storage project developers have not cited increased tariffs as an issue yet, said Rohimah Moly, deputy director of energy and climate at the California Governor's Office of Business and Economic Development.

"But we have asked developers how the proposed tariffs will impact their projects," Moly said. "A lot of the developers … are doing some behind the envelope calculations and will come back with us with some more information."

Batteries and other power equipment are also expected to see supply chain issues, Branden Sudduth, vice president of reliability planning and performance analysis at WECC, said at the meeting. The costs and lead times of transformers and switchgears continue to increase, and more than half of balancing authorities in the WECC region have said they are concerned about procurement delays for these pieces of critical equipment.

In the immediate future, between 2,100 MW and 5,800 MW of new resources will be coming online by September, the vast majority of which are battery storage and solar projects, the report says. Most battery storage energy will dispense between 7 p.m. and 8 p.m.

Although California is set to meet demand this summer under normal conditions, in a worst-case scenario, the state could need to tap into more than 2,600 MW of contingency resources, according to the report. For example, wildfires outside the state could reduce import capacity by as much as 4,000 MW, the report says.

"We have moderate to severe drought conditions this year," Jeff Fuentes, assistant chief at the California Department of Forestry and Fire Protection, said at the meeting. "In the Pacific Northwest, we have abnormally dry conditions … we also have an early spring, which causes a longer growing season."

In Southern California, several "pulses of moisture in February and March coupled with the recent rain this week is allowing green-up to continue," Fuentes added. This has also resulted in an increased yield of the grass crop and fine fuels, while drier conditions become more likely as we transition into the summer months, he said.

Additionally, there is potential for above-normal temperatures in August and September, primarily for the West, said Amber Motley, CAISO director of forecasting. The first half of summer could include above-normal temperatures that would most likely occur in the northern and central portions of the West. There is a slightly lower chance of above-normal temperatures in coastal locations, she said. ■

New Colo. Law to Streamline Siting of Tx Lines Along Highways

Bill Intended to Speed up Construction Timelines, Reduce Environmental Impacts

By Elaine Goodman

Colorado Gov. Jared Polis signed a bill May 9 that proponents say will streamline the building of new transmission lines within state highway rights-of-way.

House Bill 25-1292 lays out a series of steps for a transmission developer and the Colorado Department of Transportation to take if the two agree that a state highway right-of-way may be a suitable site for a new transmission line.

"By building in existing rights-of-way, transmission developers in Colorado can avoid the kind of political and legal pushback that slows projects down," said Randy Satterfield, executive director of NextGen Highways. The group promotes the use of existing rights-of-way such as highways as corridors for electric and communications infrastructure.

The bill aims to "open channels of communication that will allow for more coordinated and efficient planning between transportation officials and utilities," NextGen Highways said in a release.

Renewable energy industry group Advanced Energy United said HB 25-1292 would facilitate coordination among utilities, state agencies and transmission developers looking to build in highway rights-of-way, "enabling faster, cost-effective solutions that will support Colorado's clean energy goals."

And the text of the bill notes that building transmission lines in highway rights-of-way could potentially reduce impacts on wildlife and habitat, compared to building across undeveloped areas.

Why This Matters

The bill could help Colorado meet the $4 billion in transmission investment the Colorado Electric Transmission Authority has said is needed to ensure that the state's grid can keep up with demand.

"This will accelerate project timelines while reducing disruption to communities and the environment," bill co-sponsor Rep. Junie Joseph (D) said in a statement after the House passed the bill. "By establishing a clear and responsible permitting process, we're supporting a safer, more sustainable transition to clean energy."

Other bill sponsors include Rep. Andrew Boesenecker (D) and Sen. Faith Winter (D).

Multistep Process

HB 25-1292 applies to transmission developers including private parties, the Colorado Electric Transmission Authority (CETA), utilities, and generation and transmission cooperatives.

Upon the request of a transmission developer, the DOT must provide its best available information on future state highway projects that could have an impact on transmission line placement.

If the DOT and the developer agree that a site seems suitable for a transmission line, the DOT will develop a pre-construction plan review schedule. A developer that meets pre-construction requirements would then submit a constructability, access and maintenance report. The report must include strategies for mitigating impacts on wildlife, habitat and communities, including disadvantaged communities, along with a community engagement process.

The developer also must post project information, including the route selection process, on a publicly accessible website.

The bill also contains provisions for a developer to compensate the DOT for use of the highway right-of-way. Options include a $600/mile surcharge each year of a 20-year term or a $12,000 lump sum payment. DOT may adjust the surcharge according to inflation. Access can be renewed at the end of the 20-year term.

Colorado's HB 25-1292, which the governor has signed into law, sets up a process for transmission developers to build new lines within a state highway right-of-way. | *AARoads*

Another compensation option is an in-kind infrastructure exchange in a public-private agreement.

The DOT will conduct rulemaking related to transmission lines in highway rights-of-way.

CETA Partnership

NextGen Highways and CETA worked together to launch an effort last year called NextGen Highways Colorado.

The coalition represents energy, transportation electrification, business, environmental and wildlife interests. It provided input on HB 25-1292, which is also known as the NextGen Highways bill.

The effort comes as CETA has identified the need for up to $4 billion in transmission investment to ensure that the state's power grid can keep up with demand.

"Co-location of transmission in existing rights-of-way is an important tool that will assist the Colorado Electric Transmission Authority with avoiding property rights conflicts and building needed infrastructure," CETA Executive Director Maury Galbraith said in a statement. ■

ISO-NE Discusses Details of New Prompt Capacity Market

By Jon Lamson

ISO-NE and NEPOOL members discussed how to address market power, tie benefits and resource qualification in a prompt capacity market during a three-day meeting May 6 to 8.

The RTO is working to transition its Forward Capacity Market — which features auctions held three years prior to each capacity commitment period (CCP) — to a prompt market, with auctions held one month before each CCP.

The move to a prompt market is intended to increase the accuracy of available information prior to each auction and eliminate the phenomenon of in-development resources receiving capacity supply obligations (CSOs) but not coming online quickly enough to meet them.

The RTO plans to file its prompt market proposal in late 2025. Once it completes the prompt market design, ISO-NE plans to begin working on the details of a separate proposal for seasonal capacity market changes, which would split CCPs into separate six-month winter and summer periods.

Market Power Mitigation and Resource Retirements

Responding to feedback from NEPOOL members at the Markets Committee in April, ISO-NE has walked back a proposal for a penalty to prevent the abuse of market power in the new auction format.

The market power charge would have applied to retiring resources that fail a pair of ISO-NE tests to determine whether the resource is economically viable and whether its retirement would provide net benefits to the resource owner's generation portfolio. (See *ISO-NE Outlines Market Power Mitigation Measures for CAR Project*.)

"Multiple sectors shared concerns on potential issues associated with an imposition of the market power charge," said Kevin Coopey, principal analyst at ISO-NE. He said the feedback included concerns about the "individualized nature" of market power penalties on participants found to be exercising market power, compared to the "potential regional harm."

He said ISO-NE "continues to believe that there could be benefits to a [market power charge] and may further assess such a framework after CAR [the Capacity Auction Reform initiative] is completed."

In place of a penalty, ISO-NE plans to adapt its existing process of proxy supply offers. Proxy offers would only apply to resources that fail both the conduct test and the net-portfolio benefits test and would last for one year after a resource's retirement.

The Mystic Generating Station in Boston | *Constellation Energy*

Why This Matters

ISO-NE is working to overhaul its capacity market, a key revenue source for generators in the region. Changes to the auction format and underlying methodologies could have significant impacts on market revenues.

Stakeholders at the MC generally expressed appreciation for the elimination of the proposed market power charge, while some continued to advocate for more flexibility around retirement submissions. ISO-NE still proposes to require retirement notifications to be submitted two years in advance and would not allow participants to withdraw submissions.

ISO-NE also adopted a proposal made to the MC in April by LS Power to allow accelerated retirements for requests that pass reliability and market power tests. Once a resource is approved for accelerated retirement, it would be able to retire as soon as its first month without a CSO.

Buyer-side Market Power Mitigation

ISO-NE also plans to largely maintain its existing format for mitigating buyer-side market power, economist Andrew Copland said.

Buyer-side market power occurs "when a participant with a large load-side interest attempts to lower its total capacity market costs through the uneconomic entry of a resource," he noted.

New passive demand response resources and resources smaller than 5 MW are exempt from buyer-side market power mitigation, along with new resources supported by federal or state governments to support decarbonization and resources "that do not receive out-of-market revenues from [a load-serving entity], state or political subdivision of a state."

Resources could also avoid mitigation by passing a conduct test or providing evidence showing that their sponsoring LSE "is unlikely to realize a material net financial benefit."

If a market entrant does not meet any of these criteria, it would be subject to an offer floor price imposed by the ISO-NE Internal Market Monitor.

Tie Benefits

Also at the MC, members debated how ISO-NE accounts for tie benefits in the capacity market.

Tie benefits describe the level of support the RTO expects to receive from neighboring control areas during grid emergencies. ISO-NE assumes about 2,000 MW of tie benefits, which reduces the amount of capacity it needs to procure in its capacity auction.

In recent months, New England generators have pushed back against this assumption and have argued that the RTO should not treat tie benefits as equivalent to resources with CSOs.

Bruce Anderson, general counsel for the New England Power Generators Association (NEPGA), said that because tie benefits are not supported by CSOs or subject to Pay-for-Performance penalties, ISO-NE should not reduce its installed capacity requirement to account for them.

"Rather than reduce the capacity market demand quantity based on a probabilistic estimate of the amount of energy ISO-NE can rely on during capacity deficiencies, the value of import megawatts should be grounded in actual, firm offer and delivery requirements," Anderson said.

He *argued* that the current approach "compromises system reliability" and "displaces resources willing to assume a capacity supply obligation, including those both within New England and in neighboring control areas."

Ben Griffiths of LS Power expressed particular concern about Hydro-Quebec interconnection capability credits (HQICCs) on the Phase II transmission line between New England and Quebec. HQICCs reduce the capacity charges for interconnection rights holders that financially support the line.

Griffiths argued that the current methodology gives HQICCs "preferential treatment compared to capacity," while non-interconnection-rights-holding participants are effectively "compelled to purchase HQICCs at above-market rates even when true performance-backed capacity is available at the same price."

He said ISO-NE should conform its treatment of HQICCs "with either PTF [pool transmission facilities] or capacity obligations" to boost market equity and improve reliability.

He also *emphasized* the uncertain emergency benefits associated with the lines, noting that Hydro-Quebec has not given emergency assistance to New England over at least the last seven years.

"We have no idea how much, if any, emergency assistance [Hydro-Quebec] could provide New England when needed," Griffiths said.

Other stakeholders pushed back on NEPGA and LS Power's arguments, saying that tie benefits are an important input into the ICR and are supported by agreements between neighboring regions.

At the April MC meeting, Matthew Ide, of the Massachusetts Municipal Wholesale Electric Co., said "network load customers pay for all the tie benefits that come from the PTF ties through regional transmission rates. In return, load receives the benefit of a lower ICR and less need to procure capacity to meet the ICR." (See *NEPOOL Markets Committee Briefs: April 8-9, 2025*.)

Resource Qualification

Jennifer Engelson, supervisor of resource qualification at ISO-NE, detailed the RTO's current thinking on resource qualification in a prompt auction.

New resources that have not achieved commercial operations will be allowed to participate in auction qualification activities but must come online prior to a "capacity demonstration deadline" in early April prior to the auction in May, she said. ISO-NE plans to issue preliminary qualified capacity (QC) values in February but would not finalize these values until after the demonstration deadline and a period for participants to challenge their QC values.

For intermittent resources, QC will be based on "the average of the median of the resource's net output in reliability hours for the most recent five seasonal periods," Engelson said.

For non-intermittent resources, QC will be based on the median seasonal claimed capability for the past five years. QC for non-intermittent imports and distributed energy capacity resources will be based on seasonal audit values. ■

MISO Prepping for Likely 123-GW Summer 2025 Peak

RTO Anticipating Hot, Dry Summer Ahead; not Ruling out 130-GW Peak

By Amanda Durish Cook

MISO cautioned that it is likely in for heat waves and drought this summer with a slight chance it navigates a 130-GW peak in July.

The RTO expects a coincident summertime peak of 122.6 GW, exactly the same as for July 2024. However, based on its load-serving entities' noncoincident peak forecasts, MISO reported load could drift up to 130 GW in July, a high never seen in the footprint.

In MISO, noncoincident peak forecasts represent the monthly peak load submitted by LSEs; coincident peak forecasts, on the other hand, are adjusted relative to the RTO's seasonal peaks.

According to LSEs' noncoincident peak forecasts, MISO could contend with a 127.6-GW peak even in August.

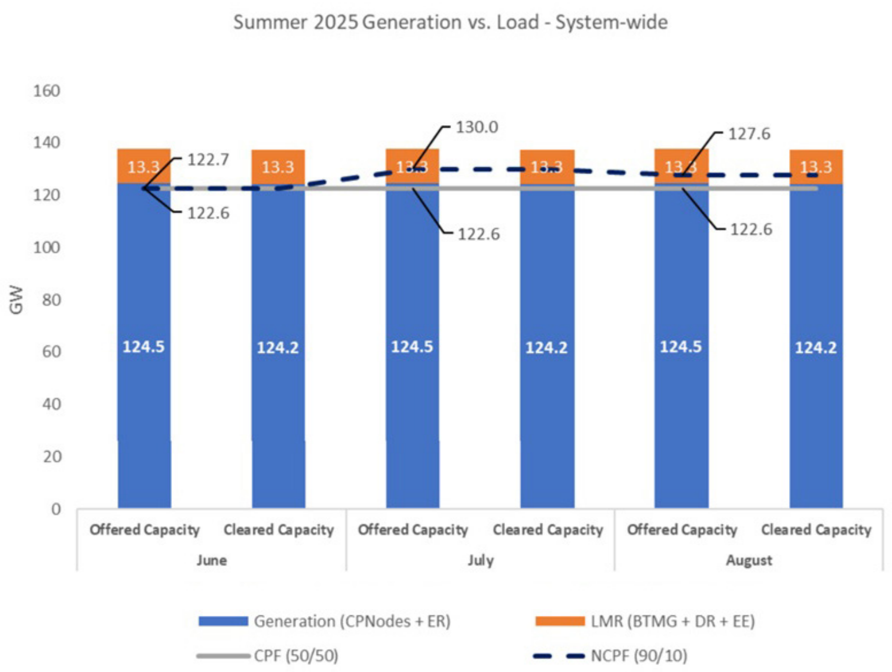
MISO's all-time summer peak of 127 GW occurred July 20, 2011. Last summer, it also warned it might eclipse that record but rounded out the season with a 122-GW peak in late August. (See *MISO: Hurricanes, Heat Wave Noteworthy Against Relatively Peaceful Summer* and *MISO Braces for Hot Summer, Potential 130-GW Peak*.)

During a May 8 summer readiness workshop with stakeholders, MISO noted that it will have more capacity than absolutely necessary when its planning year begins June 1.

The grid operator set an initial planning reserve margin requirement of 135.2 GW for summer and ended up clearing slightly over 137.5 GW because of its sloped demand curve in April's capacity auction, the first time the curve was used. It is meant to procure more capacity than strictly necessary to meet MISO's one-day-in-10-years loss-of-load standard. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

MISO's total cleared capacity includes 124.2 GW of traditional generation and 13.3 GW of load-modifying resources, which include demand response, behind-the-meter generation and energy efficiency. The RTO must declare an emergency to access its LMRs. Even if MISO realizes its most likely outcome of a 123-GW peak, the demand will require nearly all of its nonemergency resources.

When asked by stakeholders whether



MISO summer peak load versus generation. The dashed line represents LSEs' noncoincident peak forecasts. | *MISO*

What's Next

Summer. And MISO said it's likely going to be hot and dry, which could drive load past record levels.

MISO could place a probability on entering emergency procedures, resource adequacy engineer John DiBasilio pointed out that it "cleared more resources than usual" for the 2025/26 planning year and said those resources are under an obligation to offer.

"You are gaining a mandate on some additional resources to be available in the market," DiBasilio told stakeholders. He declined to guess the likelihood of MISO declaring an emergency.

The RTO said its 13-GW solar fleet, which has more than doubled in size since last summer, should also help. MISO meteorologist Adam Simkowski said it expects to have nearly 15 GW in solar capacity by July, which will translate to an average 9-GW daytime high. However, Simkowski warned that solar output is more challenging to forecast minutes ahead in the real-time market than wind generation, which currently has more predictable forecasts.

Simkowski said by August, solar contributions should be consequential enough to shave evening peaks and delay usual net peak loads by two to three hours. Because solar output tapers in the evening, MISO will have greater ramping needs, "a relatively new phenomenon" it must contend with, Simkowski said. The RTO said it plans to introduce dynamic reserve requirements that can be set to high, medium or low based on forecasts and weekday versus weekend use patterns.

MISO previously said it hopes to use dynamic reserves by the beginning of 2026. The Independent Market Monitor has warned that ramping needs beyond 10 GW are becoming increasingly common in the footprint and presenting challenges in the control room. (See *MISO IMM Warns of Operational Difficulties with Growing Solar Fleet*.)

Heat and Drought

Simkowski and fellow meteorologist Brett Edwards said they expect temperatures to trend above normal in summer, with the potential for drought over the Central U.S. to exacerbate heat waves in MISO.

They said MISO South, especially areas along the Gulf Coast, should experience more normal precipitation patterns.

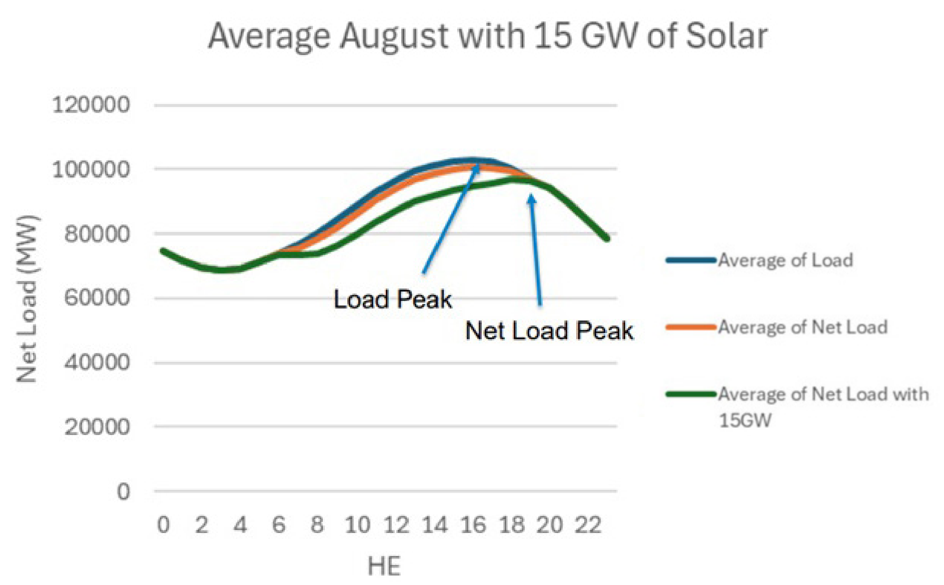
The RTO said five historical years (2012, 2017, 2018, 2021 and 2022) provide the best reference for what is likely to happen. It said all analog years had summers in which load topped 115 GW systemwide, with 2012's persistent heat and extreme drought delivering load that exceeded 120 GW for multiple days.

Edwards said the footprint might be in for a repeat of summer 2012, where load and heat were high.

MISO said over summer 2024, temperatures lined up with historical averages, and only two days in late August exceeded a 90-degree Fahrenheit systemwide temperature. The RTO is not expecting such tame temperatures this year.

The 2025 outlook lines up with the National Oceanic and Atmospheric Administration, which has called for above-normal temperatures over the whole of the continental U.S. and below-normal rainfall across most of the MISO footprint.

Finally, MISO said it anticipates a normal to slightly busier-than-usual hurricane season in the Atlantic Ocean, with an early start time similar to 2024 because of warm ocean waters in the Caribbean. ■



A hypothetical August evening peak transformed by 15 GW of solar generation | *MISO*

Stakeholders Ask FERC to Soften MISO's Proposed DR Accreditation

By Amanda Durish Cook

Stakeholders asked FERC to force MISO to cut or dilute some of the harsher requirements of its proposed demand response participation and accreditation package of revisions.

MISO in March proposed an overhaul of its capacity accreditation methods for load-modifying resources (LMRs) and DR that would be based on whether they can help during system risk (ER25-1886). (See *MISO Approaching LMR/DR Accreditation Based on Availability*.)

Comments on the proposal arrived May 5, with a majority asking FERC to give demand resources more slack in accreditation reductions, response time thresholds or exemptions for outages. Multiple stakeholders also told FERC the plan would create an inconsistency between DR accreditation and how MISO's load-serving entities prepare for peak demand.

The grid operator proposed to accredit LMRs, emergency DR and behind-the-meter generation depending on their offers during both low-margin and risky hours, when a capacity advisory, maximum generation alert or warning, or energy emergency is in place. MISO has reasoned that those hours best indicate when it is likely to need demand curtailments.

The RTO plans to split its LMR category into rapid responders with greater responsibility and slower DR with more relaxed expectations and smaller capacity values by the 2028/29 planning year. (See *MISO Closing in on New LMR Accreditation*.) More agile LMRs would have a maximum response time of 30 minutes and presumed availability for all maximum generation emergency step 2 events. Slower LMRs would have a maximum six-hour response time and would be called up earlier during maximum generation warnings.

The plan would be uncompromising: MISO would ascribe accreditation values of zero for the entirety of an emergency or near-emergency event when resources fail to contribute anything for even one hour.

Why This Matters

Some MISO market participants that operate demand response want some of the bite taken out of the RTO's stricter accreditation proposal.

MISO plans to rely on the past year to get an idea of resource availability for accreditation. That's in contrast to other capacity resources that rely on average availability over the past three years. Staff have said the accreditation is designed to be unforgiving because the RTO expects LMRs and emergency-designated DR to be available during emergencies that usually crop up after years of downtime for the resources.

The RTO would require DR and LMRs to designate a response time when registering their assets. It plans to deduct accredited values when resources report inaccurate availability.

The new accreditation would affect MISO's approximately 12 GW of demand-side capacity resources, or about 10% of its 122-GW 2024 summertime peak load.

Under the current framework, demand resources receive a 100% accreditation of their reported capacity rating. The RTO said recent data from its demand-side resource interface show that about 2 GW of DR is accredited but is never designated as available or self-scheduled in its system.

Concerns over Declining DR, and a Clash with MISO's RA M.O.

The Organization of MISO States said that while it believed the RTO's filing was acceptable overall, it harbored concerns about the new accreditation method making DR participation less attractive, the complexity of the proposal and a budding discrepancy between how the RTO sets margin requirements for utilities compared to how it accredits their DR.

Most OMS regulators agreed that MISO "streamlined and simplified" DR participation and accreditation, "although the process is still complex." The organization said it appreciated that the RTO had to react to system risk shifting away from the usual planning around a summer peak and said it was correct to try to ensure that LMRs are available when called up while cutting down on gaming opportunities and being able to access DR outside of emergency procedures.

However, OMS said it "remains concerned about the impact of the new accreditation approach on the amount of DR resources available for emergencies." It said the new structure "may make running DR programs for load-serving entities more burdensome, more costly and more difficult to explain to participating customers, making operating such programs ultimately less attractive." It warned MISO against "over-solving" a problem. It also said the RTO's "all-or-nothing" approach pressures resource owners to respond to every call or risk accreditation values.

Finally, OMS noted that MISO left a mismatch between its DR accreditation and the amount of planning reserve margin responsibilities it puts on its LSEs. It said that while margin requirements are still set by utilities' energy consumption on the peak hour, LMR accreditations would move to an availability model during risky hours that likely won't line up with coincident peaks.

MISO has said it will eventually set new reserve margin obligations based on anticipated risk rather than LSEs' load forecasts for its coincident peak. (See *MISO Ponders Redistributing LSEs' MW Obligations Based on Demand During Risky Periods*.)

OMS urged MISO to set new reserve margin obligations as soon as possible to minimize confusion.

The Illinois Municipal Electric Agency seconded the need for MISO to iron out LMR accreditation in relation to how it sets LSEs' reserve requirements. It said the current accreditation raises doubt over how LSEs will use their LMRs to meet upcoming peak demand responsibilities. The agency also said the RTO should cut its expectation of demand reductions to within 30 minutes or less to 90 minutes or more. It asked FERC to issue MISO a deficiency letter until it resolves both issues.

Minnesota Power said many of its 300 MW of demand resources have vowed to stop participating in MISO if the new accreditation and stricter testing is enforced.

"Through these reforms, MISO is requiring demand response customers to choose between being called upon far more frequently than they currently are or being called upon in a time frame that they cannot safely or commercially respond within," the Duluth-based company said. It predicted that the plan would "erode the value proposition" of industry to sign on for demand reductions, thereby driving up rates.

Minnesota Power also agreed that MISO should have worked out a companion proposal on its reserve margin assignments before introducing a proposal that is incompatible with how its other procedures define resource adequacy.

Advanced Energy United echoed concerns that the more unforgiving accreditation could block some resources from participating and could lower accreditation too much when resources take necessary outages. The trade association added that MISO was being too strict by using just the past year instead of an average of the past three years to calculate availability; by categorizing partial failures to reduce usage as total failures; and by requiring hourly meter data on demand resources and five-minute meter data during calls for faster demand resources that can respond in less than an hour.

A group of municipal utilities — Michigan Public Power Agency (MPPA), Lansing Board of Water & Light, Central Minnesota Municipal Power Agency, Northwestern Wisconsin Electric Co. and Upper Midwest Municipal Energy Group — took issue with MISO's proposal lumping dispatchable behind-the-meter generation in with DR and subjecting it to a harsher accreditation than other thermal generators, which use three-year averages to measure availability. They said the RTO would unfairly slash accreditation for a behind-the-meter generator if risky hours or an emergency event unfolds during a planned outage.

At MISO Board Week in March, MPPA's Tom Weeks said the RTO's accreditation would discriminate against dispatchable, behind-the-meter thermal generation that is built because of the difficulties with getting interconnected to the grid. Weeks said multiple municipalities rely on such generation.

"I guess if I were to use a phrase to convey my concerns, it would be, 'throwing the baby out with the bathwater,'" Weeks said.

However, the Coalition of Midwest Power Producers (COMPP) said more nuanced participation and a stricter accreditation for DR are necessary considering MISO will rely on DR more as the fleet evolves and reliability risk enters high season. It said the RTO took a step toward making sure its DR fleet is "prepared and capable of performing as expected and needed during periods of system stress" and is paid commensurate with the value it provides the system.

Big River Steel Plant in Arkansas | *SMS Group*

COMPP also said MISO's stepped-up testing will help cut down on market participants collecting payment for phantom load reductions, citing recent instances that include dummy company Ketchup Caddy and aggregator Voltus. (See *Voltus Agrees to $18M Fine to Settle DR Tariff Violations in MISO*.)

"The current capacity construct for demand resources at MISO has been built by piecing together disparate retail programs from the various MISO member states. However, this fragmented and *ad hoc* approach is no longer sufficient for MISO to meet the rapidly evolving demands of the grid," the coalition said.

Voltus itself protested the filing over what it called an overlooked provision: MISO would cease allowing DR aggregations to cut use down to a predetermined baseline and instead require specific megawatt reductions.

"Many demand response resources, from the largest industrial loads to small commercial manufacturers, respond to deployments by turning off all loads except for non-curtailable baseload," Voltus argued.

The aggregation company said instead of a drastic accreditation, MISO could be better served by launching an availability requirement for DR where assets must show they dropped use near or to accredited values or risk replacing their capacity or buying out their shortfalls at the latest capacity auction clearing prices.

A second group of utilities clustered around the Great Lakes also maintained it wasn't fair that MISO would never allow behind-the-meter generation a planned outage without it risking its accreditation value. It also asked FERC to allow demand resources three years of average availability for accreditation purposes like other generators.

Entergy also said demand-side resources should be afforded an average of three years of past performance for a larger sample size for accreditation. The corporation seconded requests for exempted planned outages for behind-the-meter generation and to allow aggregations to dip to a firm service level instead of reducing by a megawatt amount. ■

MISO's AC Rekindles Talk on Gas-electric Coordination Frustrations

Committee Schedules More Topics for June Board Week

By Amanda Durish Cook

After a hiatus on gas-electric coordination discussions, MISO's Advisory Committee touched on lingering frustrations in 2025 and potential solutions.

This time, MISO members pointed out that new electric storage could mitigate risk at times when high demand causes the natural gas supply to falter. The Advisory Committee's roundtable May 7 was one of its periodic "current issues" discussions, with more topics planned in June.

John Wolfram, representing MISO transmission owners, said he expected it would continue to be a challenge to supply gas plants in high demand using a pipeline system that was designed to support heating only. Wolfram said TOs would like to see 24/7 gas operations, especially since scarcity occurs in extreme weather that strikes indiscriminately.

"It always seems like these emergencies occur on a four-day holiday weekend," Wolfram said.

The Union of Concerned Scientists' Sam Gomberg said battery storage waiting to interconnect in MISO's queue could help MISO navigate gas shortfalls during punishing weather. MISO's queue contains about 60 GW of energy storage.

Gomberg also said more regional and interregional transmission lines could lessen the pressure to perform for MISO's key natural gas generation and make forced outages during system stress less noticeable.

MISO's Advisory Committee in session in March in New Orleans | © *RTO Insider*

Why This Matters

The MISO Advisory Committee's talk on electric-gas coordination differed from past discussions. This time, members were hopeful that some of MISO's 60 GW of storage in the queue could help the RTO survive a bitterly cold holiday weekend when gas is hard to come by and forced outages multiply.

"These aren't one-off events anymore," Gomberg said of extreme weather episodes. "I think MISO should be incorporating these into their long-term planning."

Xcel Energy's Susan Rossi, also representing MISO TOs, said a multiday commitment model from MISO could help natural gas resources better prepare.

MISO in 2024 said it wouldn't entertain a member request to create a multiday fuel purchase requirement for market participants during extreme cold weather. However, the RTO said it likely would create a financial guarantee by the 2025/26 winter for resources that are committed days in advance and have those commitments canceled by MISO. (See *MISO Proposes Alternative to Multiday Gas Purchase Requirements*.)

Clean Grid Alliance's David Sapper said while firm fuel procurements and dual-fuel conversions on plants could alleviate some risk, a "less expensive" option could be better unit commitments from MISO.

Sapper also said battery storage, which could be charged with natural gas generation ahead of time, could help MISO ride out long, stormy weekends when gas becomes scarce.

Sapper said the lack of weekend service "in times of incredibly high need does not square with competitive markets and outcomes." He said it remains "puzzling" to him that gas trading shuts down without regard to need.

Committee members agreed MISO has been handling fierce winter conditions better than ever. (See *MISO: Better Preparations Clinched Winter Storm Operations*.) However, some said it's difficult to separate how much of the improved operations are due to MISO's better forecasting and data or improved gas-electric coordination.

More Topics in June

The Advisory Committee will *discuss* emergency preparedness and power restoration procedures when it meets in June with the MISO Board of Directors in the audience.

Clean Grid Alliance's Beth Soholt asked that MISO sectors be allowed more input when selecting topics to discuss in front of the board rather than MISO's C-suite determining themes.

Advisory Committee Chair and Indiana regulator Sarah Freeman agreed there's still "a degree of opacity" in how MISO leadership chooses the subject matter for Advisory Committee sessions during quarterly Board Week meetups.

For its separate, "current issue" discussion format in June that is not held in front of MISO board members and handpicked by the committee itself, the Advisory Committee decided to discuss MISO's most recent capacity auction and how the new sloped demand curve influenced results. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

The committee maintains an ongoing list of future topics. Potential upcoming discussions could feature a possible minimum transfer capability between RTOs and how to best prevent future episodes of market manipulation à la Ketchup Caddy. (See *In a Pickle: FERC Issues $27M in Fines over Ketchup Caddy DR Deceit*.) ■

NYISO to Include Empire Wind in Q2 STAR Base Case

By Vincent Gabrielle

NYISO is modeling the Empire Wind offshore wind project as in-service despite federal orders to cease construction, staff said in presenting updated assumptions for the second-quarter *Short Term Assessment of Reliability* (STAR) to the Transmission Planning Advisory Subcommittee meeting May 6.

Alison Stuart, NYISO manager of reliability studies, explained that a scenario would be included in the modeling that would factor Empire Wind as out of service, but it was included in the base case.

Stakeholders questioned why the Empire Wind project was still assumed under the base case rules, citing the Trump administration's targeting of the project. (See *Feds Move to Halt Construction of Empire Wind 1*.)

"Can you explain why? It's clearly on hold," a stakeholder asked.

"We don't have any information from the developers regarding a delay of service date," said Ross Altman, senior manager of reliability planning.

"You might not have anything from the developer, but there's an executive order signed by the president of the country," the stakeholder replied.

Altman responded that NYISO is tracking the news regarding Empire Wind closely, but that the project still met their base case inclusion rules.

The first-quarter STAR reaffirmed that New York City needed the Gowanus and Narrows peaker plants to maintain summer reliability into 2027. (See *NYISO Reaffirms Need for NYC Peakers in Summer*.) Stuart explained that the second-quarter STAR would include the deactivation of three generator units at Gowanus and Narrows, representing 64 MW of nameplate capacity. The deactivations do not include the plants' other units at Gowanus and Narrows that the ISO designated to remain in service after their scheduled retirement under the state Department of Environmental Conservation's peaker rule.

Stuart went on to explain that in terms of load forecast assumptions, the ISO was using the 2024 Gold Book's projections, as the 2025 edition is not coming out in time for the study. In response to stakeholder questions, Altman said that the Gold Book was usually out in time for the third-quarter STAR.

Why This Matters

The Empire Wind project is considered dead in the water at the moment, but NYISO said the project had met its rules for inclusion in the Q2 STAR base case.

"It just seems like you're using very old load data, especially for New York City," responded Chris Casey of the Natural Resources Defense Council. "There were conversations about whether we should be using that forecast in the Q1 STAR, and here we are using it for the Q2."

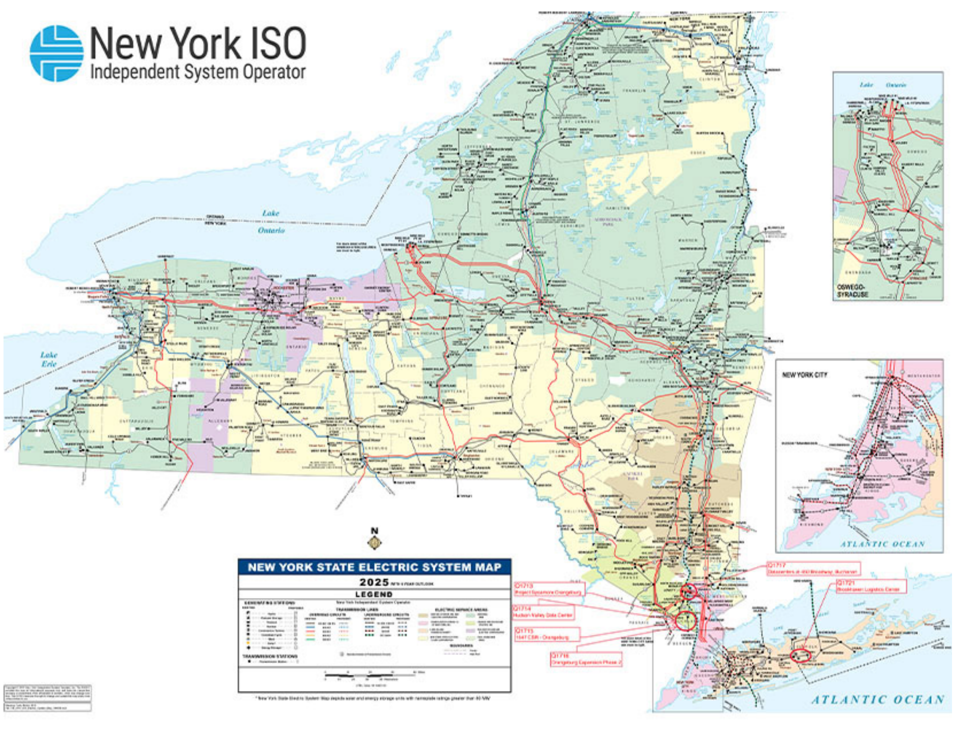
The ISO is also still modeling cryptocurrency mining and hydrogen production loads as "flexible" and able to turn off during peak conditions. A stakeholder asked why this was the case, given that several interconnection studies the ISO had presented to TPAS earlier in the meeting were going to be so inflexible. Altman said that those projects were data centers and not cryptomining or hydrogen facilities and that data centers were already modeled as inflexible load.

NYISO staff also presented updates on the biennial Comprehensive Reliability *Plan* (CRP) in development.

Last year the CRP found a reliability need in New York City by 2033, but the ISO determined this year that the need had been resolved after updating its forecasts. (See *NYISO Cancels 2033 Reliability Need for NYC*.)

Altman said NYISO is still extremely worried about uncertainties and diminishing reliability margins for the city, particularly in transmission security.

The CRP, Altman said, will focus on identifying and quantifying looming uncertainties on the planning horizon. This would include load growth, system updates, generation project delays, winter risks, and generation retirements and failures. ■



| NYISO

NYISO Monitor Analyzing Alternative Capacity Market Designs

ISO Proposes TCC Auction Structure for Fall

By Vincent Gabrielle

The NYISO Market Monitoring Unit on May 5 told stakeholders it is independently analyzing the capacity market in *parallel* with the ISO's ongoing Capacity Market Structure Review project.

"We want to help with a bit of quantitative modeling to help reason through some of the alternative structure proposals that have come out as part of this process," said Joe Coscia of Potomac Economics. He said that his presentation to the Installed Capacity Working Group was intended to show his thinking and get feedback on possibilities. "We'll follow up with a future presentation of results, so no numbers today."

Coscia said the MMU is attempting to address the specific concerns of stakeholders with the current market. The analysis will address several questions:

- Is there still value in a market designed to attract new entry in an environment where new generation development is driven by state contracts?
- Do uniform net cost of new entry (CONE) demand curves result in "excessive rents" to existing resources?
- Do bifurcated or "retention-driven" capacity markets improve efficiency or reduce costs?

Coscia said the study includes looking at the implications of using marginal capacity accreditation factors (CAFs) rather than average CAFs. This involves studying the calculation of effective load-carrying capacity for resources on the grid.

Why This Matters

While the MMU is conducting its analysis independently of NYISO, it could inform the ISO's ongoing Capacity Market Structure Review.

Currently NYISO uses marginal CAFs, which can diminish the value of energy storage as more storage enters the market, according to a *Brattle Group analysis*.

Stakeholders asked whether the MMU's analysis would try to account for state reimbursement programs for renewable energy. Coscia said the study will include an assumption that a portion of renewable energy entry into the market would not be driven by capacity prices.

Coscia gave a brief rundown of the MMU's assumptions:

- state-contracted renewables could meet 70% of load by 2033 and 100% of load by 2040;
- 6 GW of battery storage and 9 GW of offshore wind would be satisfied by state contracts;
- load growth based on the 2025 Gold Book's forecasts; and
- imperfect market participant foresight in investment and retirement decisions.

These assumptions would underlie different market designs, which would be tested under different "technology scenarios" (i.e., all fossil units retired by 2040, dispatchable renewable energy peakers available, etc.). The goal is to examine how alternative market designs might perform under different future economic and technological conditions, Coscia said.

"What we're interested in doing is trying to simulate out the implications of what could happen if changes are made to the way that prices and settlements are being determined," Coscia said. "We have no ability to predict the future about all these market conditions that could be taking place."

He said this would be a helpful tool for looking at the tradeoffs and benefits of different market structures under different conditions.

Stakeholders also asked whether there would be sensitivities included in the analysis. Coscia said the MMU intended to look at different variations within the assumptions.

Z22, CC-BY-SA 4.0, via Wikimedia Commons

NYISO Presents Results of Transmission Congestion Contract Survey

NYISO conducted a *poll* of current transmission congestion contract market participants to see what the demand for TCCs of various durations in future auctions might be, as well as their preferred structure for this fall's centralized auction.

Ten market participants responded to the survey. On average, they wanted roughly 22% of system capacity to be available at a one-year duration. The desired capacity for a six-month duration was roughly 44%. Multiple market participants said that they wanted a percentage of the available system capacity to be reserved from the centralized TCC auctions for release in the "balance of period" auctions.

In response to the survey, NYISO proposed an eight-round auction structure. The ISO would offer 20% of system capacity as one-year TCCs across three rounds and 45% of system capacity as six-month TCCs across four rounds. Both of these would be effective Nov 1.

Effective May 1, 2026, NYISO proposes 5% of system capacity be available as one-year TCCs in one auction round. The remaining 35% of the system capacity for the winter 2025/26 capability period was already sold in 2024.

Market participants and transmission owners are encouraged to provide feedback to the ISO. ■

NYPA Hedges on NYC Peaker Plant Retirements

Increasing Uncertainty May Require Operation Beyond 2030 Target

By John Cropley

Federal policy changes and slow build-out of emissions-free generation may change the timetable for the retirement of New York Power Authority gas-fired peaker plants in New York City.

Environmental and neighborhood advocates have long sought a reduction in fossil-fuel power generation within the city, due to serious local impacts on air quality and residents' health.

NYPA had begun planning for such a transition years ago, such as by installing battery storage on the sites.

Then 2023 state legislation mandated the shutdown occur by 2030 — if doing so would not harm grid reliability or result in a net increase of air pollutants within any disadvantaged community.

On May 9, NYPA produced its *Small Natural Gas Power Plant Transition Plan*, which said there is rising uncertainty about whether reliability or air quality concerns can be met.

Advocacy groups working as a coalition called Public Power NY criticized this as excuse-making by a state entity not living up to their vision of it becoming a new driver in a lagging energy transition.

The New York Power Authority's fleet of small natural gas-fired power plants consists of these six facilities in New York City and a seventh farther east, on Long Island. | *NYPA*

When the 2023 legislation was drafted, negotiated and enacted, a clean energy transition backed by hundreds of billions of federal dollars was ramping up and New York state had a robust-looking pipeline of more than 10 GW of renewable energy generation proposals working their way through to potential construction.

Two years later, a new federal administration is racing to turn the emphasis back to fossil fuels and in some cases actively thwart renewable energy development. New York's pipeline is in tatters, with many projects having paused or terminated offtake contracts amid cost escalations.

NYPA said in the transition plan that its small gas plants — 10 simple-cycle units at six sites in New York City and one in suburban Long Island, totaling 460 MW — are among the cleanest and most efficient in the area. By law, NYPA needs to ensure that shutting them down will not cause dirtier plants to run more and degrade air quality further by doing so.

Meanwhile, electricity demand is growing and NYISO has raised reliability concerns of varying severity.

These things informed the transition plan. It reads:

"The plan concludes that, at this time, NYPA must conduct additional studies with the NYISO and expert consultants to determine the impact to air quality in disadvantaged communities across New York state, including in New York City and Long Island, when the small plants are shuttered."

NYPA will consult with utilities and the Department of Public Service to decide if plants whose retirement would not harm air quality also would not harm grid reliability by retiring.

The problem is there's "unprecedented uncertainty" about the future resource mix that would determine grid reliability.

Just three weeks before the transition plan was released, federal regulators slapped a stop-work order on Empire Wind 1, a fully permitted offshore wind project that would send up to 810 MW of emissions-free power right into New York City.

Why This Matters

The newly released plan is the latest sign of uncertainty and setbacks for New York's clean energy vision.

Clean energy advocates and public power supporters have long chafed at the pace of decarbonization in New York state, where energy development is slow and expensive.

Some of these advocates also sought for years to place a greater responsibility for renewables development on NYPA, reasoning that it could do the work at a lower cost than the private sector.

They got much of what they were seeking in the spring of 2023, when the state budget included provisions directing NYPA to start developing renewables and stop burning fossils, with the air quality and reliability caveats.

Public power advocates had been hoping for NYPA to kick off its new role with a robust 15-GW debut plan for renewables development. They were sorely disappointed when NYPA adopted a 3-GW plan and predicted a high rate of attrition.

They were disappointed again with the transition plan.

Public Power NY Co-chair Michael Paulson said May 12: "The Build Public Renewables Act directed NYPA to shut down their peaker plants by 2030 and begin to redress environmental injustices and extreme public health impacts. Unfortunately, their plan is short on detail and long on excuses for potential failure. New Yorkers deserve better: a proactive plan to shutter the peakers and a commitment to build 15 GW of public renewables to facilitate that transition."

NYPA is self-funded. Its roughly 6 GW of capacity generates about 22% of the state's electricity, most of it emissions-free hydropower. ■

PJM Stakeholders Vote Out 2 Board Members

Motion to Reconsider Scheduled for Upcoming Vote

By Devin Leith-Yessian

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

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

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

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

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

PJM Board Chair Mark Takahashi | © *RTO Insider*

Why This Matters

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

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

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

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

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

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

Transparency Concerns

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

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

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

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

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

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

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

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

PJM OC Briefs

Summer Outlook Finds Possible Reserve Shortage

The preliminary *results* of PJM's look ahead at the capacity available for this summer and the expected peak loads suggest that about 5.4 GW of demand response could be needed to maintain the 3.5-GW real-time primary reserve requirement.

The season is forecast to see a 90/10 diversified peak load of 166.6 GW for the season, with 175.6 GW of committed capacity and fixed resource requirement (FRR) resources available, plus 3.6 GW of non-capacity resources. About 13 GW of that is expected to be on outage when called on, with an additional 1.6 GW flowing out to serve firm interchange. Even with a 5.4-GW load management deployment, PJM said it may fall 1.5 GW below the day-ahead scheduling reserve requirement (DASR).

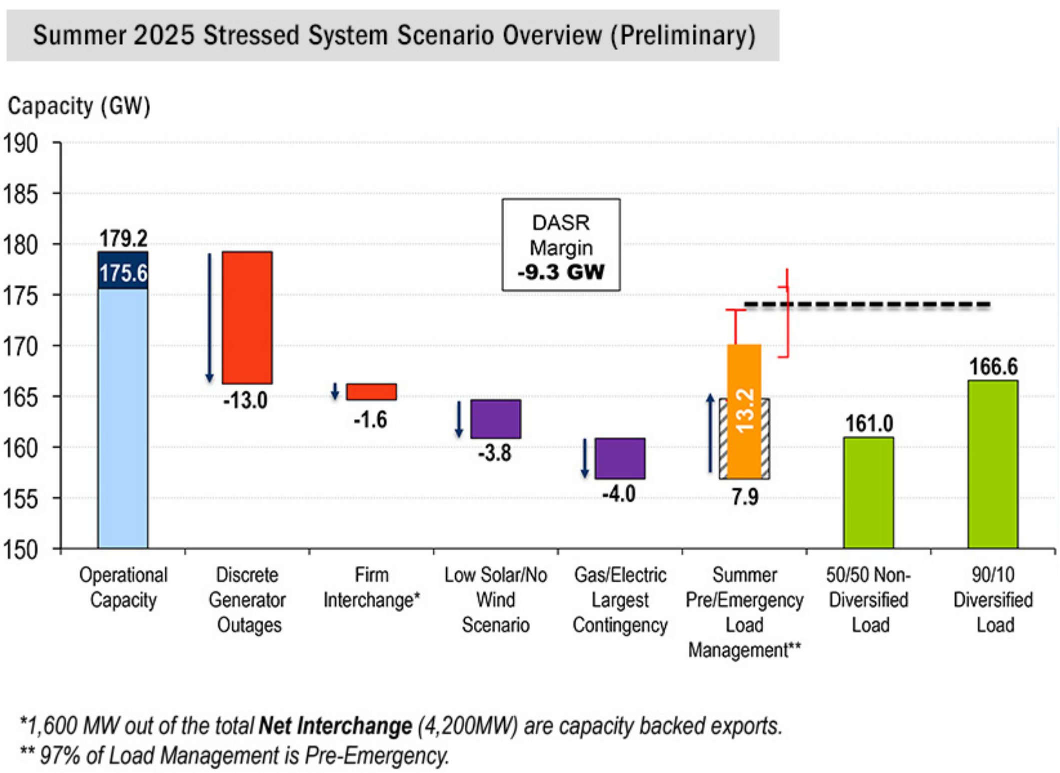
An *announcement* of the outlook described the 90/10 forecast as an "extreme planning scenario" and noted that the generation expected to be available remains above 160,961-MW peak load in the 50/50 forecast. No reliability violations were identified in the Operations Assessment Task Force's (OATF) summer report.

"This season also marks the first time in PJM's annual assessment, however, that available generation capacity may fall short of required reserves in an extreme planning scenario that would result in an all-time PJM peak load of more than 166,000 MW," PJM said in the announcement.

PJM's Mark Dettrey told the Operating Committee that the OATF report focuses on meeting the forecast peak load, whereas the 90/10 analysis included reserve requirements.

In the low solar and no wind sensitivity, 3.8 GW of renewable resources are modeled as being unavailable, leading to the system falling 1.3 GW short of the DASR target and triggering a 9.2-GW load management commitment. The single largest gas-electric contingency scenario would take slightly more off the grid at 4 GW with similar impacts. PJM also modeled the two combined in a "stressed system scenario" and found that could cause a 9.3-GW DASR shortfall and require 13.2 GW of load management.

Dettrey said the drivers are in line with the resource adequacy concerns PJM has been airing over the past few years: deactivating generation, sluggish new resource entry, and accelerating load growth fueled by data centers and electrification. The outlook shows there is increased risk of emergency procedures, such as capacity deployments, and that PJM will be "heavily reliant on" good generator performance, Dettrey said.



The results of the 90/10 summer 2025 outlook found that the RTO may not be able to meet day-ahead reserve requirements in some scenarios. | *PJM*

April Operating Statistics

Presenting the April operating metrics, PJM's Marcus Smith told the OC the month saw an average forecast error rate of 1.45%, just shy of the 1.5% benchmark, and a peak error of 1.34%.

Three days surpassed the 3% day-ahead forecast error rate, with low temperatures leading to a 3.62% overforecast of the peak load April 8. During the MIC meeting May 7, PJM presented how rapidly ramping load that morning caused reserve shortage conditions, driving high LMPs.

April 27 and 28 both saw underforecasting as higher-than-expected temperatures contributed to high consumption.

PJM experienced two spin events, two shared reserve events, five high system voltage actions, one geomagnetic disturbance warning and 11 post contingency local load relief warnings.

The first spin event was initiated at 4:21 a.m. April 5 and lasted eight minutes and 23 seconds, with 1,755 MW of generation and 452 MW of DR assigned. The generation resources had a response rate of 87%, and 89% of the DR responded.

The second event was at 12:50 a.m. April 24 in the Mid-Atlantic Dominion (MAD) zone and lasted seven minutes and three seconds. There was 1,085 MW of generation assigned, 86% of which responded. No DR was assigned. ■

— Devin Leith-Yessian

DOJ Seeks PJM Market Data for Review of Constellation-Calpine Merger

By James Downing

The U.S. Department of Justice's Antitrust Division is looking into Constellation Energy's proposed purchase of Calpine, sending an information request to PJM for market data by May 30 as part of its review.

"The Department of Justice request of PJM is not unusual for a transaction like Constellation's acquisition of Calpine," Constellation said in a statement. "We proposed a robust plan for satisfying the Department of Justice's review of the transaction, and we are confident that our filing will be approved in a timely manner. Once approved, Constellation will be even better positioned to deliver reliable and affordable energy to our customers from coast to coast."

The proposed merger is the largest in years among independent power producers, and while the two firms have operations across the country, they overlap most in PJM, where potential market power issues have dominated the debate in FERC's docket for the deal (EC25-43). (See Constellation-Calpine Merger Draws Protests over Market Power Concerns in PJM.)

FERC filed a notice April 14 seeking comment from parties in the docket on proposed communications between its staff and DOJ's Antitrust Division while its own review is pending. That was not opposed by either side, though a group of protesters asked FERC to file reports on any communications, while Constellation responded that it has asked for confidential treatment of the commercially sensitive information in the docket.

"The applicants support any interagency communication that will lead to a more efficient review and approval of the application," Constellation told FERC.

DOJ's request to PJM seeks a broad range of market data since Jan. 1, 2023, including details on every generator in the market and all of the participants in auctions for energy, capacity and financial transmission rights. It asks for details on all generators' bids into PJM markets, any outages and the resulting locational marginal prices.

The request also seeks information on net flows over transmission lines for the real-time and day-ahead markets and the transfer capabilities of the lines PJM manages, including warning levels and transfer limits.

DOJ also wants details on all imports and exports, including the entities behind them and their contract path. It also asked for transfer capabilities between PJM and its neighboring systems on an hourly basis.

The request asks for every time the three-pivotal-supplier test was applied and led to mitigation of generators in the energy markets. It seeks breakdowns by year for how many hours specific generators had their offers mitigated.

DOJ also wants information on the capacity market dating back to the 2024/25 auction, held in 2022, including every local delivery area's demand curves, details on every generator's offer into the market and details on generators using the fixed resource requirement alternative.

Finally, the department is seeking details on the entire market's portfolio of FTRs and auction revenue rights since Jan 1, 2023. ■

Calpine's Jack A. Fusco natural gas-fired power plant southwest of Houston | *Calpine*

PJM MIC Briefs

Stakeholders Discuss DR Participation in Regulation Market

PJM's Market Implementation Committee discussed a *proposal* to revise its governing documents to allow demand response (DR) resources to participate in the regulation market when there may be energy injected at the customer's point of interconnection (POI).

Curtailment service providers (CSPs) would be required to have a net energy metering (NEM) agreement with the relevant electric distribution company (EDC) and explicit approval from that EDC to allow participation alongside injections. The same change is also part of PJM's larger proposal to comply with FERC Order 2222, but some members have expressed a wish to have the capability implemented before 2028, when the Order 2222 implementation is set to go live.

PJM's Pete Langbein said allowing DR participation at POIs with injection would require some software redesign.

Intelligent Generation CEO Jay Marhoefer said the company supported the proposal at the Distributed Resources Subcommittee (DISRS) because DR aggregators can only get injection rights when they have a wholesale market participation agreement (WMPA) or similar arrangement with PJM. When a DR resource provides regulation service, injection is allowed under an NEM tariff, but there is no longer uncounted energy and thus a WMPA no longer applies.

Representing DR providers, Bruce Campbell of Campbell Energy Advisors said it is arguable that a customer with a NEM agreement that includes the capability to inject energy cannot participate in the markets as DR. He said such configurations could be operated as DR when the injections are not wholesale energy.

1st Read on 3rd Phase of Hybrid Resource Rules

PJM's Maria Belenky *presented* a set of proposed manual revisions to codify the third phase of PJM's rules for hybrid resources, which would expand the rules to configurations in which non-inverter generation is paired with storage. (See "Third Phase of Hybrid Resource Rules Endorsed," *PJM MRC/MC Briefs: Nov. 21, 2024*.)

For generation paired with storage, participation in the energy and ancillary service markets is based on PJM's Energy Storage Resource Participation Model. For hybrids composed entirely of non-inverter resources, rules for participation are similar to those for wind and solar generation

The changes would allow the resource owner to decide whether the storage component of a hybrid should enter PJM's market as open-loop capable, meaning it can charge from the grid, or closed-loop capable, limiting it to charging only from the generation components of the hybrid. Belenky said current practice dictates that if a storage resource is considered open-loop if it is physically capable of receiving energy from the grid, even if that does not reflect how the storage is operated.

Hybrids with a capacity obligation and composed entirely of inverter generation must meet their requirement to offer into the energy market by providing their economic maximum equal to or greater than the hourly forecast for each component of the hybrid. If there is a battery component, the offer should reflect the expected intermittent and storage output, including the "roundtrip efficiency of the battery." The resource owner can use either PJM's forecast or supply its own.

The changes also include adding a description of the formula used to determine lost opportunity cost (LOC) credits for hybrid resources that are instructed by PJM to charge to maintain reactive reliability. Resources are eligible for credits when locational marginal pricing (LMP) is lower than its offer.

The changes rewrite portions of Manual 11: Energy & Ancillary Services Market Operations, Manual 27: Open Access Transmission Tariff Accounting and Manual 28: Operating Agreement Accounting.

Stakeholders Endorse Market Suspension Rules

The MIC endorsed a slate of *revisions* to Manuals 6, 11, 28 and 29 to conform with a 2023 FERC order approving a PJM proposal to define how it proceeds with settlements under a market suspension. (See "First Reads on Manual Revisions," *PJM MIC Briefs: April 2, 2025*.)

The filing established three sets of rules for determining real-time prices when suspensions last less than six hours, between six and 24 hours, or for longer periods. Shorter suspensions would average real-time prices for each hour before and after the outage; moderate-length outages would use day-ahead prices if available or an average of real-time prices for the intervals before and after the suspension began; and suspensions longer than a day would use an aggregate supply curve (*ER23-1431*).

For the day-ahead market, prices would be set to $0/MWh and real-time output and prices would be used to determine settlement.

Regulation compensation would be based on a market-clearing price calculated by PJM based on the average prices in the hour before and after a suspension lasting less than one day. For longer suspensions, the highest-cost resource in each hour would set the clearing price.

The price for synchronized, non-synchronized and secondary reserves would be based on the average price in the hour before and after a suspension for events shorter than six hours. If a suspension lasts between six hours and a full day, the day-ahead market-clearing prices would be used, and for events longer than a day, prices would be set to $0/MWh and LOC would be paid to resources.

PJM Presents on April 8 Reserve Shortage

PJM's Brian Chmielewski *presented* information on a reserve shortage April 8 that caused shortage conditions to be declared in the RTO and Mid-Atlantic Dominion (MAD) subzone between 7 and 7:15 a.m. Colder-than-expected weather during the morning caused load to ramp up more quickly than forecast, limited ramping capability was available at the time and imports were scheduled to reduce by around 900 MW.

The event drove LMPs to $3,586.99/MWh at 7 a.m., with an RTO synchronized reserve deficit of 199.4 MW, a 792.6-MW primary reserve shortfall and 379.7 MW deficit in MAD, all of which was at the $850/MW penalty factor. Prices increased in the following 5-minute interval to $3,700/MWh before falling to $2,786.10/MWh at 7:10 a.m. ■

— Devin Leith-Yessian

PJM PC/TEAC Briefs

Planning Committee

PJM Presents Additional Detail on RRI Selections

PJM Director of Interconnection Planning Donnie Bielak *presented* additional details about the projects selected for expedited interconnection studies through the Reliability Resource Initiative (RRI) to the Planning Committee on May 6.

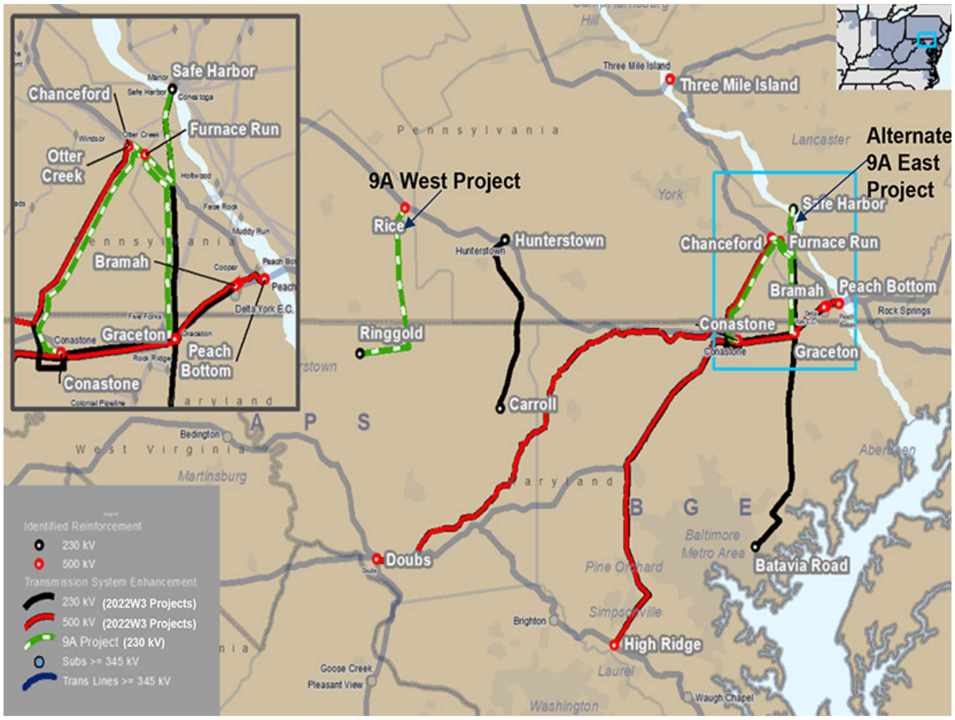
The one-time program is designed to allow a limited number of resources to enter the next study cycle based on the amount of capacity they would provide, as well as their locations and expected in-service dates. (See *PJM Selects 51 Projects for Expedited Interconnection Studies*.)

In a May 2 announcement of the results, PJM said 51 projects totaling 11,793 MW of nameplate capacity were awarded positions in Transition Cycle 2 through the initiative, 39 of which are uprates of existing resources while 12 are "new construction" projects.

The RRI projects are expected to start coming online this year, with four to be completed in 2025, six next year and 10 in 2027. One existing project receiving additional capacity interconnection rights (CIRs) was listed as being completed in 2023 in Bielak's presentation. Each project, whether it was selected or not, has been added to PJM's Cycle Service Request Status *webpage* with queue numbers AH1-674 and above; Bielak said there are no projects outside of RRI intertwined with those queue numbers.

Bielak said the initiative is now considered complete by PJM, and any projects not selected will have their deposits refunded. Even if some of the projects with RRI positions withdraw from the queue, he said PJM does not plan to allow others to take their place.

Because RRI was meant to address localized resource adequacy shortfalls that PJM is projecting in 2029, stakeholders questioned why some new projects with longer construction timelines were selected over uprates that could be more quickly completed. Bielak said some new developments had characteristics that outweighed the in-service date. The ranking process awarded 35 points for unforced capacity (UCAP); 20 for effective



The two segments of the Transource Independence Energy Connection project. The RTO is considering abandoning the eastern section of the route. | *PJM*

load-carrying capability (ELCC) rating; 10 for projects sited in Dominion or BGE; 10 for being able to enter commercial operation between 2028 and 2031; 10 points for providing evidence of permits, siting or equipment procurement to support the in-service date; and 5 points for using existing transmission headroom.

Several stakeholders asked if PJM could provide more information about how specific projects were scored to the public or the applicants, but Bielak said those results "cannot be discussed in any capacity" for data confidentiality reasons.

The Natural Resources Defense Council's Claire Lang-Ree told *RTO Insider* that the weighting used to rank projects led to many being selected that are unlikely to be online in time to address PJM's projected capacity shortfall, which she also sees as a significant reliability risk the region faces. Of the 51 projects selected, 21 are expected to come online between 2029 and 2031, amounting to over 8 GW of the expected capacity. She said that creates a risk that construction delays could result in projects being pushed beyond the time frame that RRI is targeting.

"The vast majority of that capacity in UCAP terms is coming online at the last minute or too late to help with the capacity crisis PJM is anticipating," she said.

Lang-Ree argued that PJM should have prioritized the in-service date rather than "double counting" the output of a project by having separate ELCC and UCAP values in the ranking. With shorter development schedules, she argued a design that selected more storage resources would have provided more certainty around the ability for the projects to start providing capacity in time for the start of the capacity shortfall. Of the 46 rejected RRI applications, 12 storage and hybrid resources had in-service dates prior to 2029, 17 were aimed to come online that year, and one had an in-service date in 2030.

She credited the RTO for reworking its interconnection queue to process applications more expeditiously and noted that it has recently announced a partnership with Alphabet and Tapestry to use next-generation software to process interconnection requests. The next area she said PJM should focus on is creating a process for replacing retiring generation with new resources on the same day that the deactivation occurs. The siloed nature of the existing CIR transfer and deactivation processes creates roadblocks for developers to take advantage of the interconnection facilities left behind after a resource goes offline, Lang-Ree said.

PJM has filed a package of changes to its CIR transfer rules with FERC, which would eliminate categorical restrictions on which resources can participate and allow applications that may consume transmission headroom. The commission has yet to issue an order on the proposal (*ER25-1128*). (See *PJM Stakeholders Endorse Coalition Proposal on CIR Transfers*.)

Transmission Expansion Advisory Committee

PJM Recommending Changes to Independence Energy Connection

PJM staff are planning to recommend that the Board of Managers revise the scope of the Transource Independence Energy Connection market efficiency project to abandon its eastern segment because of challenges with getting it approved.

The project includes two 230-kV lines, the western route running from the Ringgold substation in Washington County, Md., to the Rice substation in Franklin County, Pa., and the eastern route between the Conastone substation in Harford County, Md., and the Furnace Run substation in York County, Pa. While the Maryland portions of the project have been approved by the state's Public Service Commission, the Pennsylvania Public Utility Commission rejected the certificate of public convenience for Transource to proceed with construction in the commonwealth. A federal court invalidated the rejection in 2023, ruling that it was based on economic protectionism rather than siting issues. Construction has not commenced on either of the lines. (See *Christie Blasts PJM Pursuit of Transource Market Efficiency Project*.)

Presenting an update on the project to the Transmission Expansion Advisory Committee, PJM's Tim Horger said there are regulatory and constructability challenges with the eastern portion, leading staff to determine it is no longer worth pursuing. He said the most recent cost-benefit analysis found that the original route, an alternate route modifying the eastern leg to use existing right of way and the western component alone each passed the 1.25-to-1 ratio threshold. The original had a 3.74 ratio, the alternate a 3.42 and the western-only route 3.85.

Carl Johnson, representing the PJM Public Power Coalition, said the RTO's membership needs more information about how it conducted the analysis such that the cost-benefit ratio significantly increased for the 2025 project reevaluation. Horger said PJM can present more information about the topology and load forecast used.

Supplemental Projects

Dayton Power and Light *presented* a $480 million project to serve three new customers located near Jeffersonville and Wilmington, Ohio, by expanding several 345-kV substations and linking the Clinton, Fayette and Atlanta facilities with new 345-kV lines.

The Fayette and Atlanta substations would both be expanded to breaker-and-a-half configurations to accommodate a 25-mile double circuit between the two sites, as was well as two customer feeds from Fayette. The Clinton facility would be expanded with equipment for a new 27-mile line to Fayette and two 345-kV customer feeds. The project is in the conceptual phase with a projected in-service date in January 2031. The two Jeffersonville customers are expected to come online in September 2026 and ramp up to 1.5 GW of load by 2031, while the Wilmington customer is expected to come on in 2028 and grow to 500 MW.

The East Kentucky Power Cooperative *presented* a $566 million project to serve a new customer in Mason County expected to grow from 110 MW in 2026 to 2.2 GW by 3031. The customer has agreed to pay for all the interconnection costs.

The first phase of the project would construct two 1.5-mile temporary tap lines, one each on the 138-kV Spurlock-Goddard and Spurlock-Plumville lines. Next, a 345/138-kV switching station, to be named Mason County 1, would be constructed and tied into the 345-kV Spurlock-North Clark line with 1.5 miles of new lines. It would be outfitted with six 345-kV breakers, 15 138-kV breakers and two 345/138-kV transformers.

The next phase would expand the new substation with three more 345-kV breakers, 11 138-kV breakers and another 345/138-kV transformer. Another 345/138-kV switching station, named Mason County 2, would be constructed with eight 345-kV breakers, six 138-kV breakers and two 345-kV transformers. The second substation would tap into the 345-kV line between Mason County 1 and North Clark, and a new line would be constructed to Spurlock.

The final phase would expand Mason County 2 with three 345-kV breakers, 14 138-kV breakers and an additional 345/138-kV transformer. A third substation, Mason County 3, would be built and cut into lines between Spurlock and the two other Mason County facilities. A new 11-mile 345-kV line would be built to the existing Stuart substation. The temporary taps from the first phase would be removed when the rest of the work is complete.

PPL *presented* a $19.4 million project to rework portions of the Susquehanna switchyard to serve a 1,440-MW customer in Berwick, Pa. The customer is set to come in service in 2026 with 120 MW, growing to the full load in 2030. The transmission solution is in the development phase with a projected in-service date of May 30, 2028.

Dominion *presented* a $145 million project to address several violations in the Meadowville Load Area in Chesterfield County, Va. The work would rebuild the 230-kV Carson-Clubhouse line with new double-circuit structures and an additional 230-kV conductor. An additional 5.5 miles of 230-kV lines between Hopewell and the planned Sycamore Springs substation would be reconductored. The project is in the conceptual phase and is envisioned to be completed in the fourth quarter of 2030.

The company also presented a $135 million project to address thermal violations in the White Oak area of Henrico County, Va., through the 2025 Do-No-Harm analysis. Segments of the 230-kV Techpark Place-Darbytown, Chickahominy-Elmont, Chickahominy-Elko and Chickahominy-Bermuda Hundred lines would be reconductored, totaling around 40 miles. The project is in the conceptual phase and projected to go in service on Dec. 1, 2030. ■

— Devin Leith-Yessian

SPP Approves 6th Competitive Transmission Project

By Tom Kleckner

OMAHA, Neb. — SPP has approved its sixth competitive project under *FERC Order 1000*, a 345-kV transmission line in Oklahoma bringing "needed congestion relief" north of Oklahoma City.

There's more to come. SPP also said it has classified two more transmission projects as meeting the criteria for being considered competitive upgrades.

SPP's Board of Directors on May 6 endorsed an industry expert panel's (IEP) *recommendation* to select Transource Oklahoma, with Transource Energy, to build the proposed 38.4-mile, 345-kV transmission line. Transource expects the Mathewson-Redbud project to cost $72 million and plans to energize the line in 2027.

The board also approved a bid from incumbent transmission owner OG&E Transmission, with ITC Great Plains, as the alternate builder. Their bid, the only other one submitted, had an estimated cost of $84 million. That proved to be the deciding factor.

OG&E and ITC both voted against the recommendation in the Members Committee's advisory vote to the board. Five other members abstained from the 12-2 vote.

The IEP, comprising industry experts independent from SPP, unanimously recommended the Transource proposal. It said that while both bids were "capable" of financing, constructing, operating and maintaining the project, Transource's bid "presented an advantage primarily based on lower costs."

Why This Matters

SPP has now approved six competitive projects under FERC's Order 1000 and has two more projects waiting to be evaluated. There were only two proposals for the latest project, but the next two are more costly and could attract more developers.

Steve Strickland explains an industry expert panel's decision to select a transmission owner for SPP's latest competitive project. | © *RTO Insider*

"Because there were only two proposals, the determining factor was the cost of the project," it said.

"We felt good with that result," Steve Strickland, the IEP's chair, told the board and members. "We believed either respondent was capable of producing the project."

The panel determined the project's lifetime cost, as measured by the present value revenue requirement, would provide more than $14 million in savings to SPP customers. It said the OG&E-ITC bid provided a "more robust" engineering design that added costs and risks that "negated most, if not all, of those benefits."

The five-person IEP met virtually and in-person after the Mathewson-Redbud project reached the criteria to be classified as a competitive upgrade. The project first was identified in the 2023 Integrated Transmission Planning (ITP) assessment as an economic project with projected costs of $110 million; it was pulled from the portfolio because some of its upgrades would qualify as a competitive upgrade. (See "MEAN Appeal of ITP Fails," *SPP 'All Over' Addressing Resource Adequacy*.)

The panel evaluated the two bids through SPP's competitive TO selection process, required under *Order 1000*. It scored the bids based on engineering design, project management, operations, rate analysis and finance.

SPP Director Irene Dimitry said OG&E, the incumbent TO, will handle the substation upgrades. That lowered the initial estimate.

Transource said it was "excited to get to work building this new transmission line" and support Oklahoma's growing economy.

The developer is a partnership between American Electric Power and Evergy, focused on developing and investing in competitive projects nationwide. AEP owns 86.5% of the company.

SPP's board annually forms a pool of industry experts that might be called upon to review, rank and score the competitive proposals. The grid operator already has *solicited candidates* for this year's IEPs.

The panels will evaluate two projects that were part of the 2024 ITP:

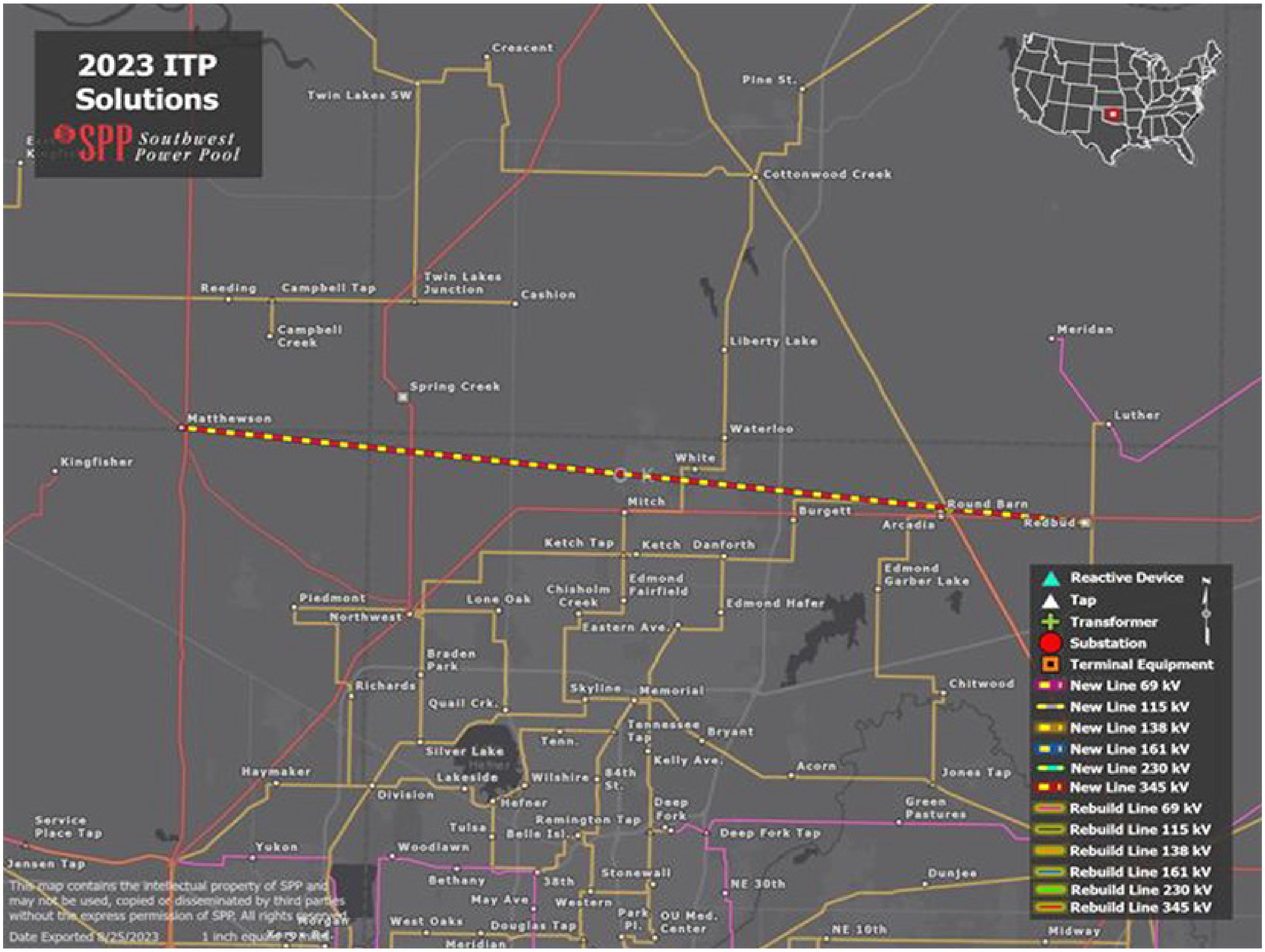
- the 345-kV Belfield-Maurine-Underwood-Laramie River project, a 438-mile line that runs from the Laramie River in Wyoming up into the Dakotas and has an estimated cost of $1.1 billion; and
- the 345-kV Elm Creek-Tobias project on the western side of SPP's footprint, an 85-mile segment valued at $887 million.

According to a *report* by consulting firm Concentric Energy Advisors critical of Order 1000's success, MISO and CAISO have considered nearly 40 competitive projects between them. SPP has considered the third most (10) and approved of six:

- North Liberal-Walkemeyer
- Sooner-Wekiwa 345 kV
- Wolf Creek-Blackberry 345 kV
- Minco-Pleasant Valley-Draper 345 kV
- Crossroads-Hobbs-Roadrunner 345 kV
- Mathewson-Redbud 345 kV

The North Liberal-Walkemeyer project later was withdrawn.

The *2024 ITP* was SPP's largest portfolio in both size and value in its 20 years as a transmission planning coordinator. The plan includes 89 transmission projects, representing 2,333 miles of new transmission and 495 miles of rebuilds — including 1,900 miles of the RTO's first 765-kV lines — to address increasing load growth and changes in the region's generating fleet. SPP expects the portfolio's benefits to exceed costs by a ratio of at least 8-to-1. (See *SPP Stakeholders Endorse Record $7.65B Tx Plan*.) ■



Mathewson-Redbud transmission project | *SPP*

SPP Board OKs 1-time Study for LREs' Gen Needs

By Tom Kleckner

NextEra Energy's Jennifer Solomon lays out her company's opposition to the ERAS proposal as the board's John Cupparo (from left), Ray Hepper and Steve Wright listen. | © RTO Insider

OMAHA, Neb. — As expected, SPP's Board of Directors has approved a tariff change that creates a one-time study outside the grid operator's normal planning process over the concerns of independent power producers.

During its quarterly meeting May 6, the board added its endorsement of a revision request (*RR668*) already approved by state regulators (the Regional State Committee) and stakeholders (the Markets and Operations Policy Committee and several working groups). The expedited resource adequacy study (ERAS) is designed to help load-responsible entities meet their RA requirements that are under pressure from large loads that have increased demand and SPP's backlogged generator interconnection queue. (See *New ERAS for SPP: Stakeholders Approve RA Studies*.)

"SPP is committed to evolving its processes to better serve our members," SPP CEO Lanny Nickell said in a *statement*. "ERAS is one part of that evolution — an innovative solution that will mitigate acute reliability risks without disrupting SPP's other processes or ongoing [generator-interconnection] queue reforms — and it comes just in time to meet the reliability needs of a quickly changing grid."

Transmission-owning members welcomed ERAS' approval. Environmental groups and IPPs did not, arguing that the study amounts to queue jumping, bypasses open access to the RTO and fails to treat all customers in an equitable manner.

"It will help those of us responsible for keeping the lights on," said Oklahoma Municipal Power Authority's (OMPA) Dave Osburn.

"This is an affront to open access and a major and significant problem for those exploring whether or not to invest in SPP," the Advanced Power Alliance's (APA) Steve Gaw said.

Brett White, senior vice president of regulatory and government affairs for Pine Gate Renewables, agreed ERAS places open access under threat. He said "undue discrimination" is being applied to interconnection customers who have invested in the current process.

"We as an IPP and our fellow IPPs will be harmed by ERAS, in several ways that are worth mentioning again," White said. "The lack of coordination between ERAS and the normal [study] process will create unanticipated curtailment and overloads on the system that will harm both groups of projects until additional upgrades are built. This is why we don't study two clusters in parallel."

White cast doubt on SPP's promise that ERAS will be a one-time proposal, saying the RTO has proposed to use the same process in the RTO Western region on a recurring basis.

"This does not reflect the supposed 'emergency' nature of this proposal and affirms concerns that ERAS is simply the beginning of a process to chip away at principles of open access," he said.

The Members Committee's advisory vote for the board passed 17-5, with one abstention. The APA, Pine Gate, Natural Resources Defense Council, EDP Renewables and Google all opposed the measure.

SPP said it remains committed to principles of independence, fairness and equity and that its standard processes will continue to ensure interconnection requests are studied fairly and efficiently. It said the proposal is necessary to respond to an "*imminent and growing need*" by adding more generation before the region's capacity is drawn down to zero.

Large loads have increased LREs' load forecasts significantly, SPP said, potentially leaving them short by 17 GW in 2030.

Why This Matters

The SPP Board of Directors' approval of a study outside the normal planning process will help load-responsible entities meet their resource adequacy requirements for 2030. Independent power producers call the proposal an 'affront' to open access and unequitable to members.

"I think of this region as a one-lane road on the edge of a cliff," board member Steve Wright said. "We're too close to the edge right now. The need to bring more generation and transmission online is a crucial component to the region."

ERAS is available only to generation projects nominated by LREs and that meet clearly defined thresholds related to near-term resource adequacy needs. It also provides a bridge to the longer-term relief expected from the Consolidated Planning Process (CPP), a separate initiative to streamline the complex and time-intensive planning process, SPP said.

"Ultimately, CPP is the answer to these problems of getting generation online faster," White said. "ERAS will only delay by further complicating planning studies and taking staff away from the crucial work of getting CPP up and running."

MOPC's approval included an amendment to extend a resource's commercial operations date to seven years because of supply chain constraints. However, the RSC took up the proposal without considering the extended timeline.

SPP plans to file the proposal with FERC later in May. Assuming the commission's approval, staff will notify LREs of the process for submitting ERAS projects as early as August, with interconnect rights being granted as early as April 2026.

The board also ran into pushback from the MC in approving a tariff change (*RR665*) that establishes "subregions" for the cost allocation of future byway (between 100 and 300 kV) upgrades. The measure decouples SPP's Schedule 9 (zonal rates) and Schedule 11 (highway/byway) transmission pricing zones and creates larger Schedule 11 subregions of existing zones. Two-thirds of the cost of byway upgrades would be allocated to the subregion where they are connected, with the remaining 33% allocated to the SPP footprint. (See "Members Pass Last of HITT's 2019 Recommendations," *SPP MOPC Briefs: April 15-16, 2025*.)

Five members opposed the proposal during the MC's vote: American Electric Power, Oklahoma Gas & Electric, OMPA, City Utilities of Springfield and Omaha Public Power District.

"AEP remains concerned whether or not this zonal approach is going to benefit customers," said AEP's Stacey Burbure, who is responsible for transmission business development and joint ventures. She pointed to no votes cast by Oklahoma and Texas regulators during the May 5 RSC meeting.

"We're concerned this could result in significant litigation," Burbure said.

Board members approved several other tariff changes and other measures previously endorsed by the RSC and MOPC:

- A provisional load process (*RR672*) that allows transmission customers to add load to the system when they don't have enough designated resources to cover their 10-year load forecast (including losses). Under the new methodology, upgrade costs will be assigned directly to the customer, with base-plan funding covering the remaining cost. (See "'Chicken & Egg' Issue," *New ERAS for SPP: Stakeholders Approve RA Studies*.)
- A structured cost-allocation method for assigning a portion of the new Consolidated Planning Process' upgrade costs based on benefits received to generator interconnection customers. The generalized rate for interconnection development contribution (GRID-C) formulas and associated cost-control approach will determine load-based cost-allocation impacts for energy resource interconnection service versus network resource interconnection service. The RSC recommended the board approve the approach to proportionally allocate incremental long-term congestion rights based on the GI GRID contribution to the overall CPP transmission portfolio cost.
- An increase to the planning reserve margin for the 2029 seasons (*RR664*). The summer PRM will go from 16 to 17%, and the 2029/30 winter PRM will go from 36 to 38%.

Nickell Focuses on Members' Needs

Nickell, making his first president's report to the board, said his vision of SPP as the best RTO in the country has evolved since the announcement of his selection as CEO in December 2024. (See *SPP Names COO Nickell to Replace Sugg as CEO*.)

"A lot of our members … instilled in my head that it's not good enough necessarily to be just the best RTO. What SPP needs to be is what's best for you, our members and our stakeholders," he said, directing his comments to state regulators and members. "That has become my slightly modified vision. It's not just to be the best RTO, but it's to be the best for those who depend on us in this footprint. Getting there will depend on a strong foundation of culture."

Nickell said SPP's stakeholder-driven culture is being challenged by the industry's rate of change.

"We will need to evolve both as a company and as an organization, to move faster than we are accustomed in order to survive and thrive," he said. "We know that we've got a generational challenge. We know that our risks are increasing because it takes a long time to get new assets and new steel in the ground."

Nickell called for more visibility in the industry, saying too often the utility business has been happy to stand in the shadows. But that all changed with Winter Storm Uri in 2021, when SPP was forced to shed load for the first time in its history and ERCOT's grid was minutes away from a complete meltdown, he said.

"It put us in a much more public position, and now our generational challenge simply compels us to be in front of utility leaders, elected officials, regulators and even consumers," Nickell said. "We have to do a better job of telling our story in order to make the change that needs to be made and to move our industry forward. We're going to have to be engaged with CEOs across the industry, with executive leadership of our members, and with government officials. We have to understand their needs, and we hope to be able to explain ours and make sure that we're moving in the right direction and at the right speed."

Nickell closed by mentioning the release of SPP's *virtual annual report* and its annual *member value statement* indicated the RTO's membership realized $3.9 billion in savings and benefits, up 7.8% from 2023 to 2024.

Cupparo Issues 'Executive Order'

Board Chair John Cupparo closed the meeting with one of his self-admitted monologues and called on staff to outline a draft proposal that will help integrate large loads with the "appropri-

SPP CEO Lanny Nickell delivers his first president's report. | © *RTO Insider*

ate acknowledgement of risks and costs" and bring it to the August board meeting.

"This one's getting heightened national attention. It also has implications on generation and interconnections beyond issues addressed in ERAS," he said. "This board is willing to push the boundaries on speed and make decisions that may not achieve total consensus in order to meet our mission, to preserve the sustainability of our model and to continue to provide the value consumers in the region have become accustomed to receiving."

Cupparo asked that the proposal be drafted with the "requisite stakeholder engagement." He included states and other national regions in the engagement that will be necessary in "pushing the boundaries."

"We believe it's important, though, that we drive a stake in the ground in terms of moving these initiatives forward, given we've got a window to respond. In my mind, the reality is we're going to need to go faster as we make additional decisions to meet our generational challenge," he said.

"Thank you for your executive order, I appreciate that," Nickell responded. Alluding to his frequent call for "the need for speed," he pointed out it took 18 months for SPP to approve a competitive project recommended in 2023.

"That's not speed, folks. We've got to get faster," he said.

Limits for Working Group Chairs

By approving the consent agenda, the board accepted the Corporate Governance Committee's recommendation to limit working group chairs to three consecutive, full two-year terms as part of its "adaptive governance effort." The committee said term limits were necessary to ensure balanced representation of various sectors and member organizations across the working groups, given the chairs' active role in determining the groups' representation.

The CGC also recommended incumbent Mark Ahlstrom, with NextEra Energy Resources, chair the Future Grid Strategy Advisory Group and Western Area Power Administration's Brianna Haug chair the Modeling Development Advisory Group. Haug previously served as the group's vice chair.

The consent agenda also included MOPC's endorsement of eight transmission upgrades with estimated in-service dates (ISDs) 90 days past their first-reported ISD, and staff's recommendation to approve four out-of-cycle evaluations for projects issued out of the 2019, 2021, 2022 and 2024 ITP assessments.

Staff said the projects are base-plan funding and any cost changes will be reflected regionally.

Nickell, who chairs the CGC, said the committee has renominated Bronwen Bastone, Ray Hepper and Steve Wright for additional three-year terms as independent directors. It will be Bastone's third year and the second for Hepper and Wright. SPP's membership will vote on the nominations during its annual meeting in November. ■

Duke Earnings Report Highlights Huge Investments to Meet Load Growth

By James Downing

Duke Energy is seeing demand growth at a level its new CEO, Harry Sideris, has not seen in his 30-year career, and that is leading to massive investments across its utilities over the next decade.

"We are ready to meet the moment with a renewed focus on speed and agility and supported by the same spirit of innovation that has been at the heart of this company for over a century," Sideris said during a first-quarter earnings call May 6. "As I assume the CEO role during this pivotal point for our company and industry, Duke Energy's mission remains unchanged: delivering long-term value for shareholders and superior service to our customers and communities by building a smarter energy future."

To support that new demand, Duke is planning to invest $83 billion through 2029 and up to $200 billion cumulatively through 2034.

That spending includes new generation and transmission and increased spending on its existing generation. The utility recently won 20-year license extensions from the Nuclear Regulatory Commission to keep its Oconee Nuclear Station in South Carolina running until midcentury. Sideris said Duke plans to do the same for the rest of its nuclear fleet.

The firm is also investing in uprates at its other generators, which are small at the individual level but add up to 1 GW of new supply across its utilities, Sideris said.

That 1 GW of new supply across its fleet is equal to the amount of load to be served under new contracts it signed with just two large users in April, Sideris said.

The company plans to merge its Duke Energy Carolinas and Duke Energy Progress utilities, which have maintained some corporate separation since it bought Progress Energy in 2012. The firm plans to file applications with North Carolina and South Carolina regulators and FERC in 2025 and hopes to complete the merger by January 2027.

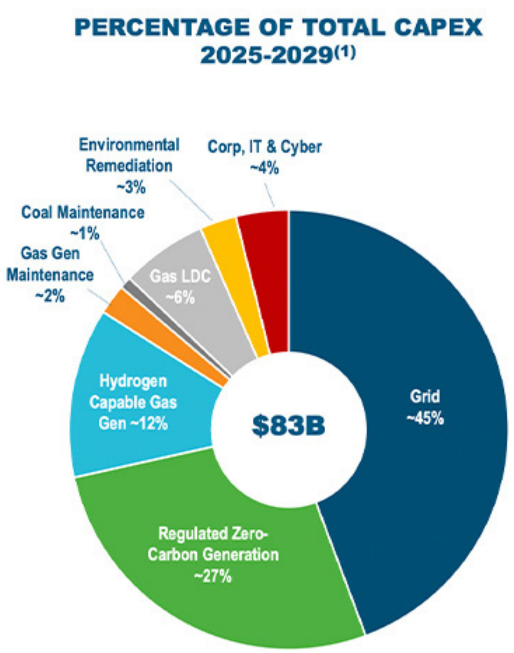
"The proposed merger would create significant customer savings, simplify operations and regulatory processes, and add operational flexibility to our system," Sideris said.

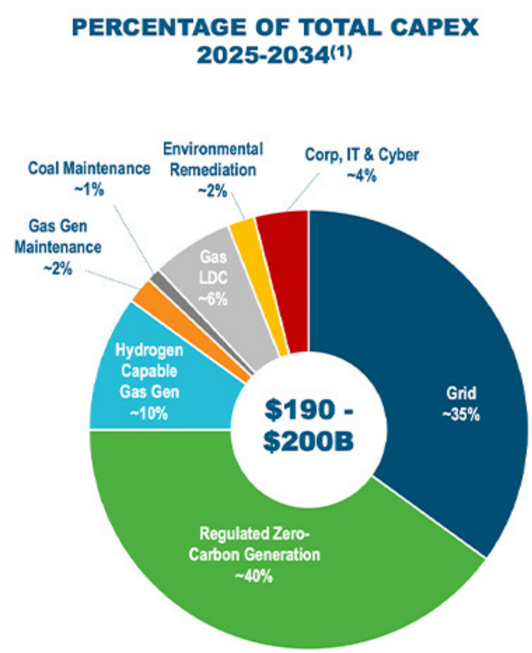
Why This Matters

Like other utilities, Duke is facing major load growth for the first time in decades, and that gives it a chance to invest in infrastructure in a major way over the next decade.

Duke is seeing growth now, especially in its Southeast utilities and Indiana, but it expects the rate will pick up this decade, CFO Brian Savoy said.

"We continue to expect load growth to accelerate, beginning in 2027 as economic development projects come online. Our economic development pipeline continues to grow and includes advanced manufacturing projects across multiple sectors, as well as data centers," Savoy said on the earnings call. "We're streamlining processes across the organization to accelerate projects through the pipeline, which is yielding results."





| Duke Energy

Duke is trying to figure out how its plans will be impacted by President Donald Trump's tariffs, Savoy said.

"It's important to remember that tariffs primarily affect capital, and the majority of our capital spend is American labor, which is not subject to tariffs," Savoy said. "We currently estimate the impact of tariffs to be about 1 to 3% of our five-year capital plan, and we are confident in our ability to further minimize the impact, leveraging our size and scale to work with suppliers across our diverse supply chain." ■

AEP to Meet Load Growth with More Infrastructure

Company to Embark on Capital Spending Plan of $54B — and Possibly More

By Tom Kleckner

American Electric Power told analysts during its quarterly earnings call that load growth, driven by commercial customers in its service territory, presents opportunities to invest in "critically needed" infrastructure.

CEO Bill Fehrman said during the May 6 call that commercial load increased 12.3% in the first quarter compared with the same period a year ago. The company has forecast "historic" total retail load growth of 8 to 9% over the next three years, driven by large-load demand in Indiana, Ohio, Oklahoma and Texas.

"This growth is not a show-me story. It is happening," he said. "As we look ahead, AEP is extremely well-positioned to participate in future growth across our footprint … to support increasing electric demand."

AEP's capital plan includes customer commitments for over 20 GW of incremental load by 2030 because of data center demand, reshoring, manufacturing and continued economic development. Fehrman said the company's investment in its 40,000-mile transmission system, which includes the nation's largest network of 765- and 345-kV lines, has been a driver behind the growth.

Why This Matters

AEP's spending plans offer another illustration of how utilities see data center growth as an opportunity to boost their own plans for growth.

"These ultra high-voltage lines position us exceedingly well in attracting hyperscalers [large data centers] to our system. We need consistent, large-load power," he said. "New infrastructure will allow us to handle this increased demand."

AEP said it has secured funding this year through two separate transactions that complete its expected equity needs for its five-year, $54 billion capital growth plan. The company said it could invest an additional $10 billion over the next five years.

This year alone, PJM selected AEP's Transource Energy joint venture and other collaborating regional utilities to complete $1.7 billion in transmission projects. In Texas, the Public Utility Commission approved AEP Texas to build one of the state's first 765-kV projects in the state. (See *PJM Board Approves $6B in Grid Upgrades* and *Texas PUC Approves 765-kV Transmission Option for Permian Basin*.)

Fehrman said the company has determined the capital plan has about 0.3% direct tariff exposure.

The Columbus, Ohio-based company *reported* first-quarter earnings of $800 million ($1.50/share), compared with just over $1 billion ($1.91/share) from the same period in 2024. It also reaffirmed its operating earnings guidance of $5.75-$5.95/share and maintained its long-term growth rate target of 6 to 8%.

AEP's share price closed May 7 at $107.48, up four cents since the earnings release. ■

AEP plans to continue to invest in transmission infrastructure. | *AEP*

As it Pursues Deals, Constellation Says Data Center Load Growth Overstated

Energy Company Paints Bright Picture with 1st-quarter Financial Report

By John Cropley

Constellation Energy said May 6 it is closing in on new power purchase agreements and is in a good position to help serve projected data center load — whether in front of the meter or behind.

During the company's *first-quarter earnings call* with financial analysts, CEO Joe Dominguez also gave optimistic updates on its acquisition of natural gas generation company Calpine and its planned restart of the former Three Mile Island nuclear plant.

Data centers were a recurring focus of the presentation, however, and Dominguez said Constellation feels the sky-high projections of the power demands posed by the artificial intelligence revolution are exaggerated — in some cases by stakeholders trying to build a business case for new wires or generation.

"I think the load is being overstated. We need to pump the brakes here," he said.

He cited as an example projections by ERCOT, MISO and PJM of a combined 140 GW of new large-load demand by 2030 and contrasted that with forecasts by third-party analysts that average out to only 74 GW of new data center demand in that period in the entire country.

"Large-load demand" is more than just data centers, but a significant portion of those new large loads are expected to be data centers.

The problem is a familiar one: developers shopping around in multiple locations with a single early-stage plan that may not even get built but which gets added to the tally of potential growth in each jurisdiction.

"We know from conversations from our customers and the end users that the same data center need is being considered in multiple jurisdictions across the United States at the same time," Dominguez said.

He added that renewable energy developers do the same thing, cramming interconnection queues with projects that have only a fractional likelihood of ever being built.

Constellation Energy

Why This Matters

Constellation is one of many companies and analysts questioning whether data center power demand will expand as greatly as some forecasts suggest.

"It's hard not to conclude that the headlines are inflated," Dominguez said. "In fact, we've done the math, and if Nvidia were able to double its output and every single chip went to ERCOT, it still wouldn't be enough chips to support some of the load forecasts. In ERCOT, there's been a history of over-forecasting."

A recent RMI analysis based on FERC data concluded that over the past decade, utilities' long-term demand forecasts were 23% higher than what actually came to pass, he added.

But Constellation does expect load growth and for that growth to present the company with a strong market position. It hopes to absorb Calpine's fleet and finish the year with more than 50 GW of operating generation in place; the cost and time frame to build a comparable new fleet would be daunting.

Constellation's Wolf Hollow and Colorado Bend combined cycle gas turbine plants, for example, would cost about 300% more today than they did when built less than a decade ago.

Crane Clean Energy Center — Unit 1 of the former Three Mile Island — is aiming for a 2028 restart. It was among the 51 projects PJM selected for expedited interconnection studies; over half of the 600 employees needed to run the plant have been hired; the first reactor operator class is underway; and the second operator class is on deck for this autumn.

In late April, Constellation answered FERC's deficiency letter on its proposed acquisition of Calpine, and the company expects the deal to be approved and to close later this year. For its $29 billion outlay, Constellation will gain generation capacity that would cost $65 billion to build new.

"The short story here is that we're seeing a very, very favorable environment," Dominguez said. "We believe our offerings for clean and reliable generation are far more attractive from a time and pricing standpoint than any competing option, whether that's used to support on grid data center development or behind the meter development."

Possible headwinds facing Constellation include tariffs, a recession and hotly debated regulations on generation being co-located with load.

Past recessions historically resulted in a 1 to 4% decrease in demand, with weather patterns complicating any attempt to generalize the relationship between the economy and demand. This time around, the demand growth that is occurring would offset a temporary economic slowdown, Dominguez said. Also, the production tax credit for Constellation's nuclear fleet gives the company downside protection from falling power prices during a recession.

The final shape of tariffs remains to be seen, Dominguez said, but Constellation's preliminary estimate is for a 1 to 2% impact on 2025-2026 capital expenditures, excluding fuel, but a negligible impact on operations and maintenance.

The outcome of the co-location debate is not clear, Dominguez said, and the industry desperately needs clarity. One byproduct of the controversy, he added, is that utilities have sped up the interconnection process. He applauded them for that and urged FERC to allow for some latitude in its rulemaking.

"It's important that FERC not constrain innovation for co-generation and co-location," he said.

Constellation *reported unadjusted GAAP income* of $118 million ($0.38/share) in the first quarter of 2025, down from $883 million ($2.78/share) in the same period in 2024.

It reported adjusted non-GAAP earnings of $673 million ($2.14/share) in the first quarter of 2025, up from $579 million ($1.82/share) in the same period in 2024.

The company's stock price soared May 6 after the release of the financials, closing 10.3% higher as the three major U.S. stock market indexes all closed lower. ■

NRG to Buy 13 GW of Generation Capacity from LS Power

VPP Operator CPower Included in $12B Transaction

By John Cropley

NRG Energy will acquire 13 GW of gas-fired power plants and virtual power plant operator CPower from LS Power.

NRG and LS *announced the agreement* May 12 and said the cash and stock transaction is valued at about $12 billion, or roughly half of new-build cost for the assets.

NRG said the 18 natural gas facilities would roughly double its generation capacity. They are spread across nine states but are concentrated in areas where most of NRG's existing load is located.

CPower, meanwhile, is an LS Power subsidiary that offers 6 GW of VPP capacity to more than 2,000 commercial and industrial customers in all of the deregulated U.S. energy markets.

NRG also reported *solid first-quarter financials* May 12. Its stock price soared after the announcements, reaching a new all-time high in heavy trading and closing 26.2% higher than the previous close May 9.

Why This Matters

The transaction would double NRG's portfolio as power demand and costs are expected to steadily increase.

In a joint news release, NRG and LS pitched the advantages the deal would offer NRG:

- New quick-start capacity in the Northeast and Texas, simplifying risk management and lowering costs.
- An immediate and strong value proposition, even without factoring price increases in tightening markets or large load prospects such as data centers.
- Better ability to service rapidly growing demand for tailored long-term supply solutions, particularly data centers.
- Potential for more than 1 GW of uprates, sites for possible development or co-location, and a differentiated commercial and industrial VPP platform.

NRG CEO Larry Coben said in the news release: "We are in the early stages of a power demand supercycle, and we are excited to lead the way with reliable energy solutions that will drive considerable value for NRG and all of our stakeholders."

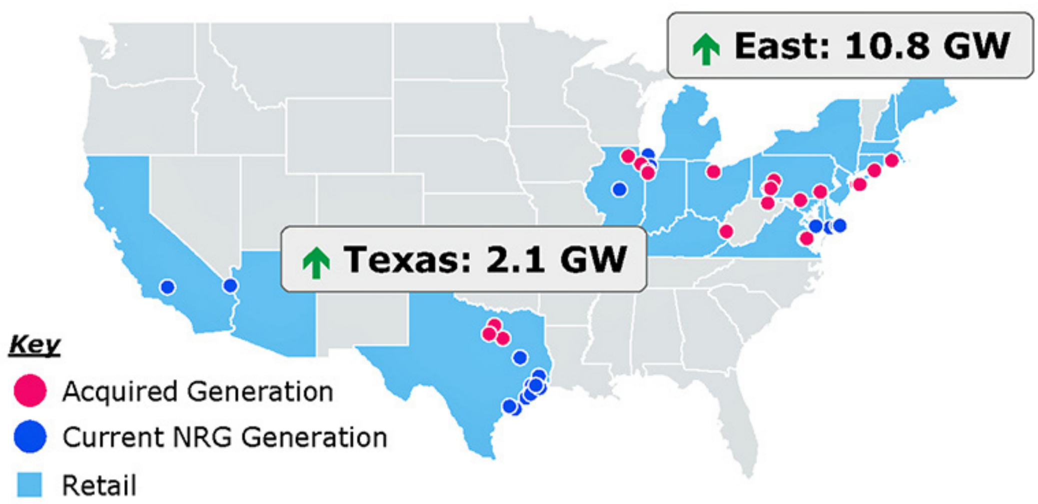
The acquisition is expected to close in the first quarter of 2026. It is subject to FERC and New York State Public Service Commission approval as well as federal antitrust review.

The sale would leave LS with about 10 GW of storage and natural gas and renewable generation capacity, as well as about 800 miles of existing transmission assets and 350-plus miles under construction.

LS CEO Paul Segal said the portfolio is uniquely suited for growing demand in the markets it serves and is being placed in capable hands. "LS Power will continue to invest in and develop secure and reliable energy infrastructure across the U.S.," he said.

NRG reported GAAP net income of $750 million for the first quarter of 2025, or $531 million after adjustments, up from $511 million and $305 million in the same period a year earlier. The adjusted EBITDA set a first-quarter record for the company.

First-quarter 2025 earnings per share were $3.70 (GAAP) or $2.68 (adjusted), compared with $2.36 or $1.46 a year earlier. ■



(GW)	NRG		Portfolio Acquisition		Pro Forma
Generation	11.9	+	12.9	=	24.8
C&I VPP	2.0[1]	+	6.0	=	8.0

The generation facilities NRG Energy has agreed to buy from LS Power complement NRG's existing retail markets. | *NRG Energy*

Company Briefs

TC Energy to Expand Pipeline to Serve Data Centers

TC Energy, a Calgary-based natural gas and energy company, has approved a $900 million natural gas pipeline project in the Midwest to serve gas-fired power plants which intend to power the region's growing data center market.

The Northwoods pipeline expansion project is expected to add 400,000 MMBtu of new capacity and increase the storage capacity of the system by 0.4 billion cubic feet per day. The project will expand the ANR pipeline, which covers more than 10,600 miles delivering natural gas from Texas, Louisiana and Oklahoma to Wisconsin, Michigan, Illinois and Ohio.

More: *Data Center Dynamics*

Grain Belt Express Awards $1.7B in Contracts

The Grain Belt Express, an 800-mile electric transmission line to be built through Kansas, Missouri, Illinois and Indiana, last week announced $1.7 billion in contractor awards.

The awards were made to Quanta Services of Houston and Kiewit Energy Group of Omaha.

More: *Kansas Reflector*

Total Seeks Permit for $16B Green Hydrogen Project in Chile

Subsidiaries of energy major TotalEnergies have applied for an environmental permit for a $16 billion green hydrogen and ammonia project in southern Chile.

The project, run by the Chilean subsidiary TEC H2 MAG, is expected to begin operations in 2030 and includes a wind farm, seven electrolysis centers for green hydrogen, a desalination plant, an ammonia plant and maritime infrastructure for shipping.

According to the project's website, the environmental permit process is expected to take two years, with construction to begin in 2027.

More: *Reuters*

Rivian to Build $120M Supplier Park in Illinois

Rivian last week said it would invest $120 million to build a supplier park near one of its plants in Illinois.

The supplier park near Normal, Ill., will reduce shipping, logistics and warehousing costs, while adding hundreds of jobs in the next two years, the company said. Rivian builds all its EVs at the Normal plant.

More: *Reuters*

Federal Briefs

DOE Grants Export Permit for 2nd Venture LNG Terminal

The Department of Energy last week granted an export permit for a second Venture Global LNG terminal alongside the Calcasieu Pass facility in Cameron Parish, Louisiana.

The proposed terminal was the fifth LNG-related approval from the department since President Donald Trump took office.

Louisiana has four LNG terminals with two more under construction.

More: *Grist*

Trump Admin Cutting Energy Star, Climate Reporting Programs

The Trump administration is cutting EPA's Energy Star program, which highlights energy-efficient home appliances, according to sources.

According to one source, staffers were told that Energy Star was being eliminated, as is the Climate Protection Partnerships division that houses it. Staffers were also told EPA was cutting its Climate Change division, which includes the agency's Greenhouse Gas Reporting Program. The program requires major polluters to report their emissions.

More: *The Hill*

DOE Lays Off 114 at NREL

At least 114 people were laid off at the National Renewable Energy Laboratory last week, according to a leaked email.

The email, sent by the "NREL Leadership team," implied the cuts would help the lab focus on its longer-term mission and help it shift its resources to "critical priorities."

The cuts come as the Trump administration aims to slash DOE's budget by nearly $20 billion, with deep cuts to the office that funds NREL's operations. Those cuts are not final and must be approved in a budget passed by Congress.

More: *CPR News*

State Briefs

INDIANA

I&M Seeks URC Approval to Buy Wind Power

Indiana Michigan Power last week said it is seeking approval from the Utility Regulatory Commission to buy more than 570 MW of wind energy.

I&M submitted its Future Ready Integrated Resource Plan to the commission in March. That plan called for adding power created from diverse sources, including wind. I&M will buy power generated from five wind farms in Indiana and Illinois, totaling about 575 MW.

I&M expects the new resources to be available to serve customers next year.

More: *The Journal Gazette*

MASSACHUSETTS

Appeals Court Says Permits for Palmer Biomass Plant Still Valid

The Massachusetts Appeals Court last week revived Palmer Renewable Energy's 15-year fight to build a biomass power plant.

In the ruling, the court said deadline extensions meant to prod development in the wake of the Great Recession meant Palmer Renewable Energy's permits are still good and didn't expire due to lack of action by builders.

The case is likely headed to the Supreme Judicial Court on appeal.

More: *MassLive*

MICHIGAN

House OKs $100M for Ice Storm Aid, Exempts U.P. from Clean Energy Law

The state House of Representatives last week voted 107-1 to approve a $100 million appropriation to aid northern residents in their recovery from a March ice storm.

The appropriation for the State Police, which was increased from $75 million in an amendment, would be distributed to local governmental units and used to assist "individual residents, businesses and communities that have realized a significant financial hardship caused by recent storm damage."

In separate votes, the House also passed legislation that would exempt the Upper Peninsula from new laws requiring communities to achieve certain renewable and clean energy goals by 2035.

More: *The Detroit News*

State Won't Lease Land for Solar Project

The Department of Natural Resources last week said it will not move forward with a proposal to lease 420 acres of state land near Gaylord to a solar energy developer.

The decision follows months of debate about the proposal, in which opponents expressed environmental concerns, fear of losing public access or ideological opposition to renewable energy. The furor prompted officials to pause any additional consideration of solar leases and extend a public comment period on the Gaylord-area proposal by several months.

By the time the vetting process began, RWE Renewables had already withdrawn its interest. In a letter to several legislators and interest groups, DNR Director Scott Bowen cited the company's retreat and public concerns as reasons to not move forward.

More: *Bridge Michigan*

MONTANA

Gianforte Signs MEPA Bills into Law

Gov. Greg Gianforte last week signed into law a handful of bills revising the Montana Environmental Policy Act.

One of the new laws enumerates six greenhouse emissions the state must inventory in environmental reviews of energy projects but explicitly directs agencies like the Department of Environmental Quality not to regulate them. Another measure bars state agencies from adopting air quality standards stricter than federal regulations.

Another bill strikes a considerable amount of existing code and repeals entire sections of environmental law.

More: *Montana Free Press*

OHIO

Court Rejects Householder, Borges Appeals in Bribery Case

An appeals court last week upheld the convictions of former House Speaker **Larry Householder** and ex-Republican Party Chairman Matt Borges.

"There was ample evidence for the jury to conclude that Householder solicited and received millions of dollars from FirstEnergy in return for passing and then preserving bailout legislation. We won't disturb that decision," the appeals court panel wrote in its decision.

Householder is serving 20 years in federal prison. Borges is serving five.

More: *The Columbus Dispatch*

OREGON

Portland Rejects PGE Plan to Run New Tx Lines in Forest Park

The Portland City Council last week rejected a plan by Portland General Electric to cut down 5 acres of trees for new transmission lines that will run through Forest Park.

The council said the utility failed to demonstrate a need for expanding the grid.

PGE said construction of the new lines would require cutting down 376 trees and filling two wetlands. To offset the lost trees, PGE planned to plant 400 in the project area, another 400 elsewhere in Forest Park and more trees in overheated Portland neighborhoods.

More: *Willamette Week*

VIRGINIA

Halifax County Split on Solar Projects

The Halifax County Board of Supervisors last week voted 4-4 on conditional use permit applications for two solar sites.

After the board voted 4-4 on the applications for the sites known as the 5-MW

Nathalie L and 3-MW Nathalie C, tie-breaker Wayne Smith opted to delay his vote. Smith said he would like to visit the sites before casting his vote on the applications, out of fairness for both parties.

Smith will vote on the permits at the board's June 2 meeting.

More: *YourGV.com*

Youngkin Vetoes Energy Storage Targets Bill

Gov. **Glenn Youngkin** last week vetoed legislation that would have raised the targets for how much new energy storage Dominion Energy and Appalachian Power must propose adding over the next two decades.

The bill would have more than tripled the amount of new storage the utilities would need to propose adding to their portfolios by the end of 2045 under the Virginia Clean Economy Act.

Youngkin initially sent the bill back to the General Assembly with a substitute that would have essentially gutted the act by repealing Appalachian and Dominion's renewable-energy requirements. After legislators rejected his substitute, he vetoed the bill.

More: *Cardinal News*

WISCONSIN

PSC Approves MGE Solar, Storage System

The Public Service Commission last week approved Madison Gas and Electric's plans for a 20-MW solar array and a four-hour, 40-MW battery storage system in Fitchburg, known as the Sunnyside Solar Energy Center.

The solar array is scheduled to come online in 2026, while the battery system is expected to be switched on in 2027.

More: *Renewables Now*