YES ENERGY

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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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CAISO/WEST

CAISO CEO, Others Point to Reliability Aspect of BPA's Market Decision

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While the specific effects are uncertain, the migration of entities from CAISO's WEIM to SPP's Markets+ likely will have big implications for how the West manages grid reliability.

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CAISO/WEST FERC/FEDERAL

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FERC Leaders Focused on Stability amid Political Shifts (p.13)

FERC's role is to follow the law and ensure the fairness of procedures because decisions affect whether investors will put up "literally hundreds of billions of dollars into the assets that we need to invest in," Chair Mark Christie said.

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SOUTHEAST

Southern Co.

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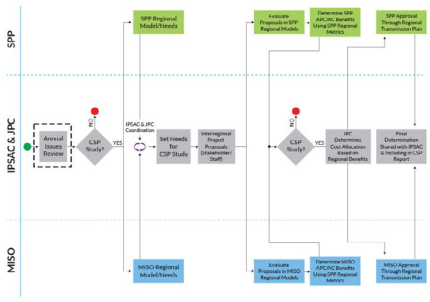
The report says a bolder planning approach is needed, especially since meaningful regional transmission projects have failed to materialize for more than a decade.

MISO SPP



MISO, SPP

MISO, SPP Solicit Feedback on Joint Transmission Studies (p.41)

MISO and SPP staff are asking for stakeholder input as they consider a joint system study in 2025. The staffs will use the feedback before they make a decision this year on a 2025 study.

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In this week's issue

NEMA Report Forecasts 50% Electric Demand Growth by 2050

By James Downing

Electricity demand will grow by 50% over the next 25 years, according to a report released April 7 by the National Electrical Manufacturers Association (NEMA).

Data center demand is expected to grow by 300% over the next 10 years, with most of that happening in ERCOT and PJM, the study says. That represents 32% of the 1,323 TWh of forecast growth through 2037, while electrification of transportation makes up 24%.

For the 1,360 TWh between 2038 and 2050, transportation makes up 51% of the forecast, followed by industrial demand at 28%, while data centers represent just 1%.

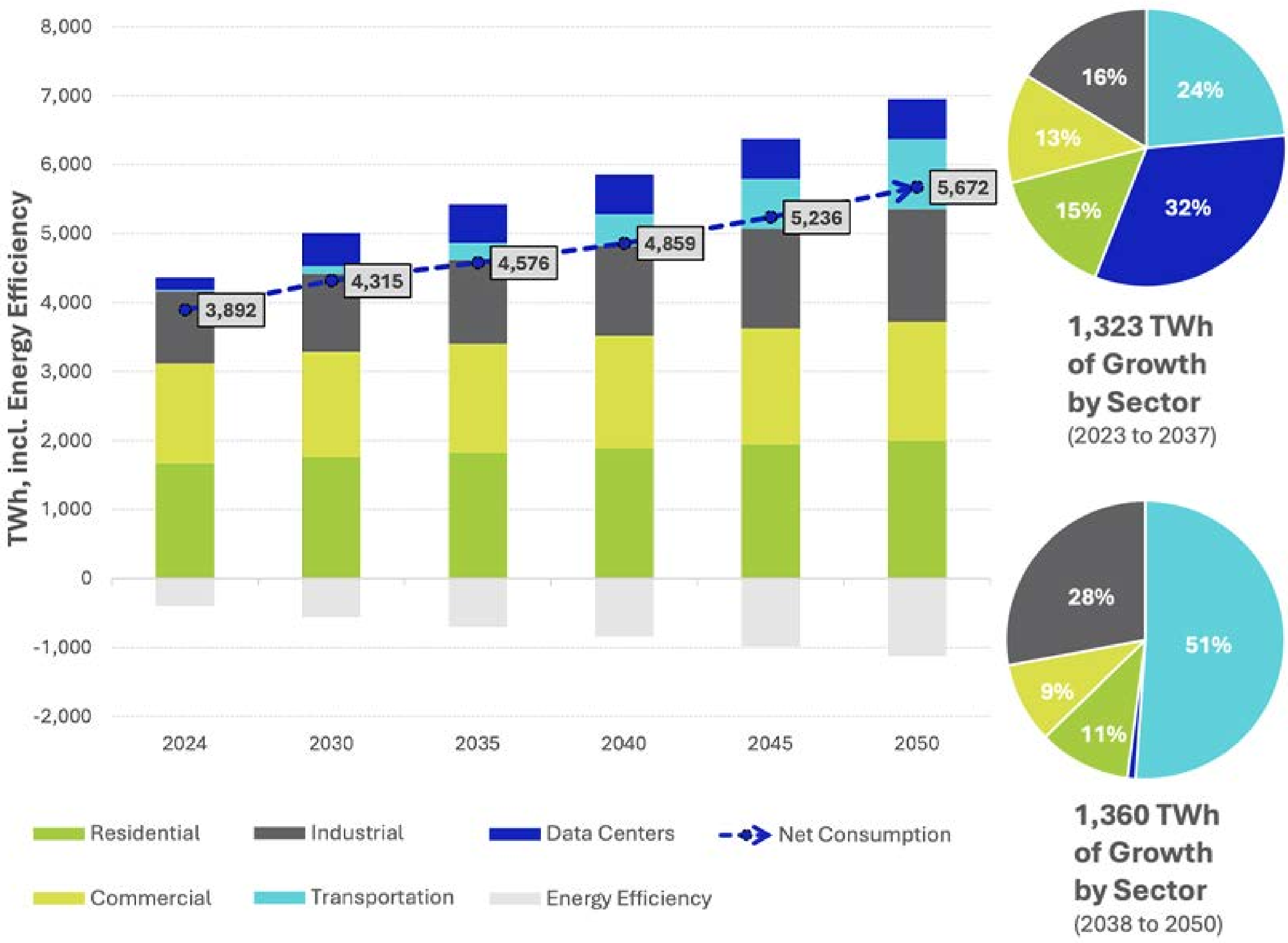
The overall projected growth works out to 2% per year and follows years of low load growth across most of the U.S. as energy efficiency offset new sources of demand, NEMA CEO Debra Phillips said on a call with reporters April 4.

"This 50% growth that we're looking at over the next 25 years is fairly remarkable, and our grid wasn't designed really to meet that," Phillips said. "So, we're going to have to get creative around the technology and policy solutions that are going to help us meet the demand."

Why This Matters

The manufacturers of key pieces of grid infrastructure and end-use appliances see power demand growing by 50% over the next 25 years, requiring significant investment on their part.

The new growth will require new generation, transmission and other infrastructure, but Phillips said the industry would



Forecasted sources of electricity demand growth over the next 25 years | *NEMA* need to do more to maintain reliability.

"We've grown more efficient over time," Phillips said. "It's been key to us keeping that demand curve flat in recent years, and we're going to continue to get better in that efficiency space. And so that, I think, is the real difference maker in our study versus others, is that we're really leaning into that concept of efficiency, and our products really enable that."

NEMA represents manufacturers of the grid's backbone infrastructure, including lighting, motors, wire and cable, she said.

While demand is forecast to grow the fastest in PJM and ERCOT in the first half of the forecast, the shift to EVs in the second means the West and Northeast should see the highest rates of growth, Phillips said. Between now and 2050, electricity is expected to grow from 21% of final energy use to 32%.

In terms of new generation, the report forecasts its capacity will grow by 43% to 1,761 GW nationally, with most of the growth in renewables and storage as fossil generation declines slightly. NEMA's forecast has 409 GW of gas running by 2043, while the U.S. Energy Information Administration expects the gas fleet to total just 126 GW by 2050 and a National Renewable Energy Laboratory study has it falling to 189 GW by 2050.

NEMA is releasing the study after President Donald Trump announced wide-ranging tariffs, which will impact manufacturing supply chains around the globe, include the group's members. Since 2018, NEMA members have invested $185 billion in domestic manufacturing, and its goal of reshoring some industry aligns with Trump's goals, Phillips said.

"Another aspect of the trade world that the electrical industry finds itself in is an ecosystem that's very connected in North America," Phillips said. "So, trade with our Mexican and Canadian partners is really important."

The three largest North American countries have designed their entire power systems together, so NEMA values certainty and predictability around the trading rules and tariff rates between them, she added.

Predictability is important to the future of that continental trading relationship, ABB Executive Vice President Michael Plaster told reporters on the NEMA call.

"We have a switch gear plant in Mebane, N.C.," Plaster said. "We have a switch gear plant in Mexico, and they make the same thing. And to be able to flex when there is crisis is really important, without having to wonder how much is it going to cost us to flex like that."

Predictability is important, but the tariffs are going to have cost implications because going back to a world where everything is made for domestic consumption in each country is not cost effective, S&C Electric CEO Anders Sjoelin said on the call.

"There will be a cost adder," Sjoelin said. "And we're going through that because some of the components and parts that [go] into your product [are] hard to make yourself because [they're] not part of your core. ... I'm discussing that today with my team." ■

EPSA Conference Tackles Markets in a Time of Rapid Demand Growth

By James Downing

WASHINGTON — Load growth caught off guard an industry that was in the middle of a spate of retirements of older fossil fuel-fired power plants, but the markets are starting to respond, experts said at the Electric Power Supply Association's Competitive Power Summit on April 2.

PJM expects load growth of 32 GW from last year to 2030 when its peak will hit 184 GW, mostly from new data centers coming online in its footprint, said its CEO, Manu Asthana. The RTO is dealing with that through its Reliability Resource Initiative, which recently received 94 applications to build resources that will keep the grid stable in the near term. (See *PJM Receives 94 Applications for Expedited Interconnection Process*.)

"We're seeing a reaction," Asthana said. "We've seen over 1,000 MW of generation rescind their retirement notices. We have seen almost 27 GW come into our Reliability Resource Initiative."

On the morning of the event, it was announced the former Homer City coal plant in Pennsylvania was being redeveloped around natural gas to serve data centers, which comes a few months after the Three Mile Island plant signed a deal with Microsoft to reopen to serve a data center, Asthana said. (See related story, *Data Center Campus with up to 4.5 GW of Gas Generation Planned for Pa.*)

Policy changes can help with the issue too, Asthana said. The backup generation at data centers as a potential resource cannot be used, he said, because they most often have diesel generators that have limited run-times in their permits, so their ability to offer demand response is limited.

"If we can access that flexibility — or through policy changes, increase that flexibility — even if it's for a transitional period, I think you can serve more data centers," Asthana said. "It's not that we're short every hour of the year; we're short some hours of the year."

PJM is worried about the end of this decade, but MISO has been dealing with a system running at its reserve margin target since 2022, said Todd Ramey, the RTO's senior vice president of markets and digital strategy. Some of its states are pushing policies to deal with climate change that have retired baseload power plants and favored renewables for new resources, which cannot replace dispatchable power plants on a one-for-one basis.

Why This Matters

Load growth has changed the discussion around the industry, and EPSA's conference tackled issues around meeting that demand and the benefits markets can offer in doing so, such as keeping the risks with shareholders and not ratepayers.

"So, over the last few years, we rapidly worked down our surplus spinning reserves and kind of hit the minimum," Ramey said. "Once you get to minimum, it really is all hands on deck at that point — just to figure out what we can do to maintain."

Several years after that first started, MISO was facing zero demand growth. It now expects growth of 2% annually for the next five years, jumping to 3.5% in the 2030s. In 15 years, MISO expects demand

From left: PJM CEO Manu Asthana, NYISO CEO Rich Dewey, POLITICO's Catherine Morehouse, MISO's Todd Ramey and NERC's Camilo Serna at EPSA's Competitive Power Summit on April 2. | © *RTO Insider* to grow by 60%.

NERC expects summer peak demand to grow by 132 GW around the continent over the next 10 years and winter peak to grow by 150 GW, while 115 GW of older power plants retire, said Camilo Serna, the ERO's senior vice president of strategy and external engagement.

"More than 50% of the U.S. is at risk of resource energy adequacy issues, so ... we're going to be running very, very tight," Serna said.

Another issue is the growing use of natural gas on the system, which is concerning in the winter when demand for direct heating use competes with power generation, especially during weather events.

"Weather patterns today are kind of longer, deeper and impact a broader set of regions," Serna said. "So that will continue to create a lot of resource adequacy issues."

For years the industry tricked itself into thinking that extreme weather events — such as the 2014 polar vortex, which roiled PJM's energy markets, and 2021's Winter Storm Uri, which led to hundreds of deaths in Texas and spiking prices around the country — were random and rare, Asthana said. "I think the lesson from that really is that we need to think differently about resource adequacy."

NYISO has made changes around its winter requirements, so CEO Rich Dewey said he feels more comfortable about reliability in the season as his operators can call on a fleet of dual-fuel generators to meet demand during cold snaps. But New York faces issues around keeping old legacy plants online for the foreseeable future.

Dewey started his career as a power plant engineer for Niagara Mohawk. He said he was working on plants that were expected to shut down in 2000 and still are running.

"And we're counting on them being there for at least the next 10 years of our planning horizon, and there is nothing lined up to replace them," Dewey said. "So, I worry about that. I worry about the adequacy that the plant owners have to do the necessary maintenance and life extension, which is going to be so crucial. I worry about having the right kind of incentives."

One of the resources New York planned to replace such plants with was offshore wind, which ran into cost overruns and supply-chain issues before an unfriendly administration took over in Washington. Another issue the Trump administration has put front and center in New York and other Northern markets is tariffs.

NYISO has set up rules to collect tariffs on any imports that flow into its system from Canada, though Dewey would prefer not to use them as the trade is mutually beneficial. New York sets its reserve margin and capacity market inputs around some baseline of imports from Canada.

"If we get into a situation where the politics escalate and we suddenly can't count on that for anything anymore, then there's going to be a real reliability issue," Dewey said.

Another issue that tariffs cause for the industry is exacerbating supply chain worries around key grid components like transformers, Asthana said.

"We have 31 tie lines with Canada," Serna said. "The systems are designed to work together electrically. So, besides the energy adequacy issues that Rich was pointing to, there are some other reliability services that we count on the two systems providing to each other: voltage [and] frequency support. So, if you have an extended period where you don't get that power from Canada, there could be other implications beyond just having enough energy to meet demand."

The changes in demand have changed the discussion around new generation, with Vistra CEO Jim Burke saying he had to explain why new natural gas generation is in vogue recently to a conference of oil and gas executives.

"I think the solution set of wind, solar and battery is not set up at the moment to meet 24/7 loads that [data centers] have," Burke said. "It's also not set up to meet the retirement of coal and the growth on the electric grid. So, gas has proven itself as a more near-term, viable, dispatchable, reliable solution."

Debating which specific technology is needed to meet the rising demand is a 1990s issue, Competitive Power Ventures CEO Sherman Knight said. The industry needs to build everything it can.

"If you let the markets work and you send the right price signals, it will react, and we will react to that," Knight said.

In addition, "taking off the handcuffs" from every type of technology so it can help meet the demand will enable the industry to rise to the challenge. And in the case of markets, both Knight and Burke noted they will pay the price for any wrong bets as they have before.

Vistra's predecessor firm made a bad bet on building a new coal plant in Texas after Hurricane Katrina caused natural gas prices to spike, Burke said.

"We brought the plant online in 2011, and by 2018, we retired that plant because natural gas prices due to fracking had come down so dramatically," Burke said. "We wrote off over $1.25 billion as a company. We did not seek any recovery of that. That should be on us; we made a bad decision. The customer didn't pay for that, and that's something I think competitive markets are not given enough credit for."

Earlier in the day, FERC Commissioner David Rosner read off a list of billions of dollars that different organized markets reportedly have saved consumers over the years.

"What's great about markets?" Rosner said. "It allows us to do more with less. It allows us to optimize around the generation and transmission assets that we have and efficiently use the system."

While it would help to get better forecasts on what actually is going to show up on the grid, regulators can be certain that demand will rise, he said.

"In places where we have markets, the goal is to make sure that we have a set of rules in place that fit the needs of what businesses want to do," Rosner said. "I personally don't have a 'one-size-fits-all' in mind on this."

Rosner said he's hopeful the commission will be able to set some rules on data center co-location so the industry can move forward and meet that demand.

"The only other thing I'd say is I hope that our open proceeding doesn't discourage people who have developed things that they might want to bring to the commission from doing that whenever it's ready, because I personally am willing to consider things on a case-by-case basis," he added. ■

Groups Ask FERC to Axe Languishing Proposal to Cut Transmission Incentives

By James Downing

The Edison Electric Institute, GridWise Alliance and WIRES asked FERC on April 3 to end a proceeding that has been open for five years to consider cuts to transmission incentives (*RM20-10*).

The commission opened the rulemaking in March 2020 and supplemented it a year later to propose eliminating the existing RTO membership transmission incentive for utilities that have been participating in an organized market for more than three years. The proposal would have focused project-specific incentives on the benefits to customers from transmission investment.

"The commission's current transmission incentives policy is working to the benefit of customers, transmission owners and the public interest," they said in a joint filing. "With the rising demand for electricity, the commission's existing transmission incentives policy has become even more essential."

A lot has changed since the rulemaking launch, they said, including a rapid and unforeseen return to demand growth because of large data centers, reshoring of industry and general electrification pressures. The COVID-19 pandemic led to an economic slowdown and uncertainties in the economic forecasts on which the industry relies.

FERC also issued Orders 1920 and 1920-A, which are intended to identify considerable new transmission portfolios that might also introduce new risks to development because of the selection of larger and more complex projects, the groups argued. The world is also entering into a period of greater geopolitical tensions and competition, in which promoting domestic energy independence and security is considered a heightened priority.

Why This Matters

FERC first proposed trimming transmission incentives in the early days of the COVID-19 pandemic; much has changed since then.

While the three trade groups want FERC to abandon the rulemaking, they argued even if the commission wants to go forward, it should take additional comments so parties can update the record for the changes over the past half decade.

President Donald Trump has declared a national energy emergency, in which he emphasized the urgent need to revamp and expand the grid to meet growing demand and ensure reliable supply, they noted.

"This infrastructure is not only essential for accommodating the increasing power demands from various sectors, but also for maintaining and enhancing the overall resilience and efficiency of the nation's energy system, which itself underlies the broader economy," they said. "A reliable, resilient and efficient energy delivery system is the foundation to providing cost-effective electric service to customers of all kinds, thereby aligning with the administration's broader goals of fostering economic growth and energy security."

The incentives date back to the Energy Policy Act of 2005, which acknowledged that increased levels of transmission infrastructure were needed to keep costs reasonable and the system reliable. FERC implemented them in 2006 with Order 679, which established tailored incentives to address risks and challenges associated with transmission development.

"After nearly two decades, it is undeniable that the commission's transmission incentives policy has provided the signal and support for transmission investments that ultimately benefit electric customers," the groups said. As FERC considers changing the incentive policy, it has to weigh whether this would disrupt expectations, create uncertainty and possibly chill investment by eliminating rate treatments that cut risk and aid in lower financing cost to benefit consumers, they said.

| © RTO Insider

FERC's proposed change would treat the RTO adder as an incentive to join an organized market, but the groups argued that was not Congress' intent.

"The commission is, ultimately, 'a creature of statute and has only those authorities delegated to it by … Congress,'" they said. "Any action that would restrict eligibility for this incentive beyond the requirement that a transmission owner join an RTO is ultra vires [beyond its legal authority]."

RTO membership requires TOs to transfer operational control of their facilities to the grid operators, which perform functions like planning, marketing and congestion management. The grid operators can require TOs to make investments in high-risk transmission projects, with the RTO adder helping to offset that risk.

"Transmission owners in RTOs must also comply with a more expansive set of federal regulations, such as Order Nos. 719, 745, 841 and 2222, which significantly and disproportionally impact RTO regions," the groups said. "Through these actions, the commission has fundamentally altered the business model, exposed certain future capital investments of transmission owners to competition, increased the potential that investments will be delayed and deprive customers of the benefits, and created significant uncertainty and related regulatory risk."

The RTO adder offsets risks incurred in delivering the benefits of RTO membership to customers such as access to cheaper power, efficient dispatch over a wide area and enhanced reliability, which together far outweigh the cost of the adder, they argued. ■

CAISO CEO, Others Point to Reliability Aspect of BPA's Market Decision

Agency's Choice of SPP's Markets+ Could Break Ties with CAISO's Reliability Coordinator

By David Krause

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BPA's day-ahead market decision will have "major reliability and affordability impacts" on electricity customers in the Northwest and across the West, CAISO CEO Elliot Mainzer said in a *report* he presented to the ISO's Board of Governors March 26.

Mainzer's statement came weeks after BPA issued a draft policy saying it intends to join SPP's Markets+, the market competitor to CAISO's Extended Day-Ahead Market (EDAM). (See *BPA Selects SPP Markets+ in Draft Policy*.)

As BPA approaches its final market decision in May, energy leaders and experts in the West are focusing on potential reliability issues should the agency choose Markets+ over EDAM.

"We've seen a lot of changes in the last decade in the West, with gas plant retirements and a rapid rise in solar generation in California," Fred Heutte, senior policy associate at the Northwest Energy Coalition, said in an interview.

"Coordination between Bonneville and CAISO has been critical in this decade, especially when things get really tough, like under extreme weather conditions. We depend on transmission and strong coordination in the region to keep the lights on," Heutte said.

One central concern is that BPA could choose a different reliability coordinator under the Markets+ option. BPA currently relies on CAISO's RC West as its reliability coordinator, but could switch to SPP's reliability coordinator, Western RC Services, BPA's draft policy says.

Why This Matters

While the specific effects are uncertain, the migration of entities from CAISO's WEIM to SPP's Markets+ likely will have big implications for how the West manages grid reliability.

"Then the region will have two coordinators," Heutte said. "How they will work together, especially when demand is high, needs to be thought about in more detail."

Having multiple non-contiguous reliability coordinators and market operators in the Pacific Northwest "will pose many operational and commercial challenges," BPA's draft policy acknowledges.

Switching reliability coordinators could come at a price: BPA's draft shows the total internal implementation cost of Markets+ could be between $53.7 million and $74.2 million, whereas the cost for joining EDAM ranges from $29.9 million to $38 million.

The higher cost estimate for Markets+ is driven in part by an assumption that BPA switches its RC from CAISO to SPP, the draft policy says. While BPA's draft included the estimated costs for changing RCs for transparency, the agency isn't certain it will make the change, which will depend on future policy development, the document says.

In an email to RTO Insider, BPA spokesperson Doug Johnson noted that Markets+ comes with higher upfront costs, while production cost modeling analysis done for the agency shows lower revenue in Markets+ compared to EDAM. (See *BPA Sticks to Markets+ Leaning Despite Study Showing EDAM Benefits*.)

However, Johnson added, the ongoing participation fees "suggest that these upfront costs could level out over time between the two markets, with Markets+ showing potential for significantly lower market operating costs over the long-term. While EDAM's implementation fee is quite low at $3 million, the recurring annual fee is double that of Markets+."

WRAP Key Factor for BPA

From a resource adequacy standpoint, both day-ahead market options include an evaluation for resource sufficiency, but BPA has said it prefers the design in Markets+, primarily because the SPP also includes a long-term RA requirement, the agency said in its draft policy.

Markets+ includes a standardized resource adequacy requirement in which all load responsible entities must participate in the Western Resource Adequacy Program (WRAP) administered by the Western Power Pool, while CAISO's EDAM does not include any such requirement.

"While the CAISO BAA has its own RA framework, this framework is not extended to other entities outside of CAISO's BAA in general," the draft says. "Bonneville believes that Markets+ requiring participation in WRAP, a standardized RA framework, will better meet this [RA] principle."

Regardless of its market decision, BPA will be responsible for its system's reliability, and will do so by acting as transmission planner, balancing authority and transmission operator. BPA will remain responsible for compliance with applicable NERC reliability standards as well. This is because day-ahead markets and market operators do not assume any of the reliability roles of a utility — as in a full RTO, the draft says.

'Valued Partner'

In an email to *RTO Insider*, Mainzer didn't elaborate on his comment about the reliability impact of BPA's decision, but reiterated his support for the agency and its ongoing market decision analysis.

"BPA has been a valued partner to the CAISO for many years and played an essential role in the development of the Western Energy Imbalance Market (WEIM)," Mainzer said. "There is a seat at the table for BPA to remain an active member and architect of a broad, electrically connected energy market that will build on our shared success with WEIM."

Irrespective of how BPA ultimately chooses to proceed, CAISO will maintain focus on EDAM implementation and providing technical support to the West-Wide Governance Pathways Initiative (which is working to bring more independent governance to CAISO markets), Mainzer said in his CEO report.

"We are proud of the fact that the EDAM market design was crafted through an extensive and transparent process with a wide variety of stakeholders before being approved in full by FERC last year," he said in the report. This message is "a reiteration of the message that … CAISO and many others in the Northwest have been conveying to BPA over the past year," Mainer told *RTO Insider*.

WECC is also following the formation of both day-ahead markets, Kris Raper, the reliability organization's vice president of strategic engagement and external affairs, told *RTO Insider*.

In general, WECC supports the current developments because market structures allow for more effective and efficient dispatch around transmission constraints — leading to a more reliable system, Raper said.

"However, it is not WECC's role to evaluate what market, if any, would be better for a utility to join. That said, as a partner in the Western Interconnection with a mission to mitigate risks to reliability, we [will] address any concerns about reliability as the conversation evolves and the markets develop," Raper said. ■

EDAM Congestion Debate Builds Even as CAISO Moves to Address Issue

Monitor Patton Weighs in, Calling EDAM Revenue Allocation Treatment 'Highly Problematic'

By Robert Mullin

LA JOLLA, Calif. — The dispute over how CAISO's Extended Day-Ahead Market will allocate congestion revenues to market participants might induce a sense of déjà vu among Western electricity sector stakeholders who have closely followed the development of the region's day-ahead markets.

In 2024, a January deep freeze that put much of the Northwest on the brink of rolling blackouts set off a heated debate between supporters of EDAM and SPP's Markets+. That dispute centered on how CAISO allocated the revenues it collected from the transmission congestion stemming from the weather event. That controversy became a kind of proxy for the competition between the two markets. (See *NW Cold Snap Dispute Reflects Divisions over Western Markets*.)

A similar development appears to be playing out this spring, even as most Western utilities have already settled on which day-ahead market they will join — although a handful remain uncommitted.

The dispute is over the rules by which EDAM will allocate congestion revenues when a constraint in one EDAM balancing authority area produces "parallel" — or loop — flows that result in congestion in a neighboring BAA.

The issue came to light after PacifiCorp in January filed a revised Open Access Transmission Tariff with FERC to reflect the utility's participation in EDAM, scheduled to begin in 2026.

Shortly after the OATT filing, Vancouver, Canada-based energy trader Powerex — a PacifiCorp transmission customer that has committed to joining SPP's Markets+ — released a paper pointing to what it called a "design flaw" in EDAM because the market's rules do not offer "a financial hedge that returns the day-ahead congestion charges on a delivery path back to the entities with firm transmission rights on that delivery path" — as required by FERC. (See *Powerex Paper Sparks Dispute over EDAM 'Design Flaw'*.)

CAISO and PacifiCorp initially responded sharply, calling Powerex's paper "misinformed and inflammatory," but the ISO in March kicked off an "expedited" stakeholder initiative to address the issue after other Western entities filed similar complaints in the FERC docket for the OATT (ER25-951).

The Western Energy Markets Body of State Regulators meets in La Jolla, Calif., on April 2. | © *RTO Insider*

Why This Matters

The EDAM congestion revenue issue appears to be yet another proxy in the competition between the CAISO market and SPP's Markets+ as a handful of Western utilities remain uncommitted to a day-ahead market choice.

The issue was the key agenda item at an April 2 in-person meeting of the Western Energy Markets Body of State Regulators (BOSR), held in La Jolla at the site of the joint spring conference of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB).

Speaking to the BOSR, Anna McKenna, CAISO vice president of market design and analysis, emphasized that while the ISO is moving quickly to address stakeholder concerns, it disputes the contention that the market's existing congestion revenue framework is inherently flawed. (See *Fast-paced Effort will Address EDAM Congestion Revenue Issue*.)

"I know that there's been a perception out there that, because we started an initiative, we're admitting that there's some fundamental flaw in the EDAM design. We wholeheartedly disagree," McKenna said.

McKenna said the new initiative is "revisiting" what CAISO thought was just and reasonable in light of FERC's approval of the EDAM tariff in December 2023.

"And, by the way, what we have in EDAM is something that's been in place for 10 years now under [CAISO's Western

Energy Imbalance Market]. … So there was really no change in how that congestion revenue is going to be allocated in EIM and EDAM," although there will be different implications for the day-ahead market, she noted.

MISO Monitor Weighs in

McKenna delivered her presentation a few days after a new twist in the dispute, when Powerex on March 28 filed additional *comments* with FERC in the PacifiCorp OATT docket.

The comments included expert testimony from David Patton, president of Potomac Economics, which serves as the Independent Market Monitor for MISO and ERCOT and provides monitoring services for ISO-NE and NYISO.

"All other organized markets provide financial transmission rights that correspond to all of the constraints that are priced in the markets' LMPs, which is the basis for the congestion costs charged to customers," Patton wrote. "In sharp contrast, PacifiCorp proposes to only provide a hedge for congestion associated with constraints on PacifiCorp's system, and no hedge for congestion costs associated with all other constraints in EDAM."

Patton contended PacifiCorp "has proposed an unprecedented and ultimately unreasonable treatment of its firm transmission service and the customers that have purchased it." He said the proposal is "clearly inferior to both the financial transmission rights RTOs and ISOs provide their firm transmission customers and to the physical scheduling rights firm transmission customers receive in non-market areas … under the *pro forma* OATT."

Patton warned that the lack of "effective" congestion hedges could increase long-term grid reliability risks by deterring investments by "risk-averse market participants." He said PacifiCorp "could meet the requirement for transmission service that is consistent with or superior to the pro forma OATT, despite the incomplete nature of the current EDAM design," by submitting a revised OATT that preserves the ability of the utility's customers to opt out of EDAM "and schedule the use of their firm transmission service ahead" of that market.

In an email to *RTO Insider*, PacifiCorp spokesperson Omar Granados said the utility "is proceeding toward the implementation of the approved EDAM design in 2026 and continuing to work with market participants and other stakeholders to implement those design features to maximize benefits for participants and support grid reliability. PacifiCorp will engage with stakeholders in the pending FERC proceeding and the CAISO stakeholder process on congestion to address any questions or concerns."

Patton's testimony also criticized EDAM itself, saying "the design of EDAM substantially deviates from the design of other day-ahead markets in how congestion costs are collected and distributed back to the EDAM participants."

"It is highly problematic and somewhat misguided to allocate congestion revenue based on where the transmission facility is located rather than based on the sources and sinks where the congestion revenues are actually collected," he added.

But Patton also acknowledged that EDAM is not like the other markets he monitors because it does not include other elements of an RTO, such as consolidation of balancing authority areas and transmission service providers.

At the BOSR meeting, McKenna said EDAM provides a "unique" design in that it does not force transmission owners to turn over control of their lines to the market operator, allowing each to determine how to spread congestion revenue allocations among transmission users.

She argued also that implementing a financial instrument such as congestion revenue rights would not solve the problem of which BAA receives revenues stemming from congestion caused by parallel flows.

McKenna expressed confidence in CAISO's ability to address the issue.

"We're not unique in that every RTO and every ISO has had to make many filings that impact its markets over the years. That is the nature of markets: learn, react, form, and you proactively address things," she said.

"I think it's a good point you made: that markets are not static and continue to evolve as we identify potential improvements or changes — and that's good, because we get to keep our jobs," New Mexico Public Regulation Commissioner and BOSR Chair Gabriel Aguilera said. ■

Henrik Nilsson contributed to reporting in this article.

West's Mounting Challenges Require Increased Coordination, Panelists Say

WECC CEO Highlights Risks from Trump Administration's Executive Orders

By Henrik Nilsson

A panel during the spring joint CREPC-WIRAB meeting discussed the importance of collaboration in the face of mounting challenges to reliability. | © *RTO Insider*

LA JOLLA, Calif. — Regional initiatives aimed at increasing coordination and collaboration among Western power entities are essential to tackle mounting technical and political challenges, panelists said during a discussion at the spring joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body on April 2.

Many of the challenges the Western Interconnection faces are coming out of the White House, according to WECC CEO Melanie Frye.

Frye pointed to executive orders impacting the federal workforce, sweeping tariffs and funding pauses for projects in the West. All of this is coming at a time when the risk to reliability is "out front and center," Frye said in reference to wildfires in Los Angeles, data center demand growth and cybersecurity threats, among other issues.

Coordination and collaboration are key to facing these challenges, Frye said.

An example of such collaboration, according to Frye, is WECC's adoption of five risk areas the organization's Board of Directors approved last year, including:

- the effects of drought and long-term aridification on the Western grid;
- reliability challenges related to inverter-based resources;
- data accuracy and modeling of the interconnection;
- coordinated planning of the resources in the transmission system and
- energy policy

Why This Matters

The success of many efforts in the West, including new day-ahead market options and navigating federal policies, hinges on effective collaboration and coordination between stakeholders in the energy industry.

"We know we have an integrated grid, and I think it's going to take the communication, the coordination, the collaboration and the courage to make sure that we continue to keep those lights on," Frye said. "Through those four C's, I think we have tremendous possibilities to advance the desires of all of the various states and provinces that are in our footprint."

Keegan Moyer, a partner at Energy Strategies, said most of the major successes in the Western interconnection, like the Western Energy Imbalance Market, have come through regional coordinating efforts.

However, successful initiatives require trial and error, and "you have to stick with them sometimes for many, many years for them to have any benefit at the end," Moyer contended.

Additionally, state leadership in regional initiatives is "paramount," Moyer said.

"So when you look across … what we're doing now in the region, whether it be [Western Transmission Expansion Coalition], [Western Resource Adequacy Program], the activities going on in WECC, Markets+, [Extended Day-Ahead Market], all these different efforts, state engagement is critical just like it has been in the past," Moyer said.

Sarah Edmonds, CEO of Western Power Pool, pointed to WRAP as a successful initiative that has brought together Western resources and helped representatives across the energy industry find common ground "to solve the problem of a very serious and looming threat to reliability and resource adequacy in the West."

However, referencing the other speakers, Edmonds also noted there are challenges in the West, "and that has been difficult for all of us to manage."

"There's a lot of layers that you have to navigate through, and you have to make a lot of connections between initiatives and efforts that seem disconnected, but are, in fact, quite organically connected in a number of ways," Edmonds said.

Despite the many challenges, the Western Interconnection "will decide its own future," Frye said.

"And I think it's really important that we not lose sight of the fact that, you know, we're operating the grid that's existed for decades, and we know how to do that," Frye said. "We know the people in this room, and we know the people in the industry that we need to bring to the table. So I think those are important things to not lose sight of." ■

FERC Leaders Focused on Stability amid Political Shifts

By Henrik Nilsson

LA JOLLA, Calif. — FERC Chair Mark Christie and Commissioner Judy Chang downplayed the current political environment's impact on the agency, saying during an industry meeting April 3 that its role is to follow the law and ensure the fairness of procedures.

Stability comes from the commission's dedication to following the Federal Power Act and the Natural Gas Act, Christie said in a conversation with New Mexico Public Regulation Commissioner Gabriel Aguilera during the spring meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body.

FERC's decisions affect whether investors will put up "literally hundreds of billions of dollars into the assets that we need to invest in," Christie said. "There has to be a certainty and a stability before those investors are going to put up that kind of money to build the assets that we all know we need."

Christie also stressed that the commission will adhere to its *ex parte* rules.

"We're going to follow the procedural rules. There's not going to be any violation of our ex parte communications, and we're going to follow the statutes that apply to each case, whether it's Federal Power Act; whether it's Natural Gas Act," Christie said. "If you're following the statutes and your procedural rules, that's where credibility comes from. And we are."

In a separate panel moderated by Washington Utilities and Transportation Commissioner Milt Doumit, Chang said the new administration will not change FERC's mission of "keeping the lights on."

However, she noted "nervousness" around voluntary retirements spurred by the Trump administration's deferred resignation offer to the entire federal workforce in January.

"There are some uncertainties, but I think we're keeping … our eye on the road," Chang said.

Markets in the West

The two FERC commissioners also praised efforts to create day-ahead markets in the West in reference to SPP's Markets+ and CAISO's Extended Day-Ahead Markets. Both offered insights into how the industry can navigate issues between the two market options, such as seams.

Chang suggested the West look to MISO and SPP, which have created operating agreements and task forces to navigate seams, she said. She urged stakeholders to avoid imposing barriers to "allow the efficient exchanges to occur and trades to occur."

"Avoid locking in historical patterns, because when you start creating new markets, things are going to change, or policies might change, or generation fleets mix might change, or transmission buildout will change the flow," Chang said. "Try to be flexible to future changes. And that includes, really, all kinds of parameters around market design."

Christie emphasized the importance of state regulators collaborating to tackle challenges.

Why This Matters

FERC's role is to follow the law and ensure the fairness of procedures because decisions affect whether investors will put up "literally hundreds of billions of dollars into the assets that we need to invest in," Chair Mark Christie said.

"You can have the bigger meetings where 90% of the people there are not state regulators, and they're there with their own interest," Christie said. "And that's fine, as long as you, as state regulators, set aside time where you all go in a room and you talk to each other about how you're going to work through these challenging issues."

Chang's Goals

Chang, who joined FERC in July 2024, laid out her goals before her term expires in June 2029.

The West's market evolution is a priority, with Chang saying she wants "to understand it; to help you develop what you need for your customers."

Other focus areas include resource adequacy, the interconnection queue and transmission planning.

"I think the rules in [Order] 1920 are very solid," Chang said. "I would love to see parts of the country, maybe the whole country, implement better transmission planning and cost allocation and get some very needed transmission at least developed, maybe not in my term, but at least prepared for in the future."

Chang also said she "would love to see more advanced technologies be implemented as part of transmission buildout, because I think we have an obligation to serve customers in the most efficient way, and we can squeeze more out of existing infrastructure and new infrastructure." ■

New Mexico Public Regulation Commissioner Gabriel Aguilera and FERC Chair Mark Christie in conversation during the spring joint CREPC-WIRAB meeting on April 3 | © *RTO Insider*

Reliability Projects Dominate CAISO's $4.8B Draft Transmission Plan

Proposed 2024/25 Plan Intended to Accommodate 76 GW of New Capacity, Load Growth

By Robert Mullin

CAISO's 2024/25 draft transmission plan recommends 31 new projects at an estimated cost of $4.8 billion, slanting heavily toward reliability needs.

The *plan* is based on California Public Utilities Commission forecasts projecting the state must add more than 76 GW of new capacity by 2039, the ISO said in the draft.

"This reflects greenhouse gas reduction goals and load growth, including the potential for increased electrification occurring in other sectors of the economy, most notably in transportation and the building industry," CAISO wrote.

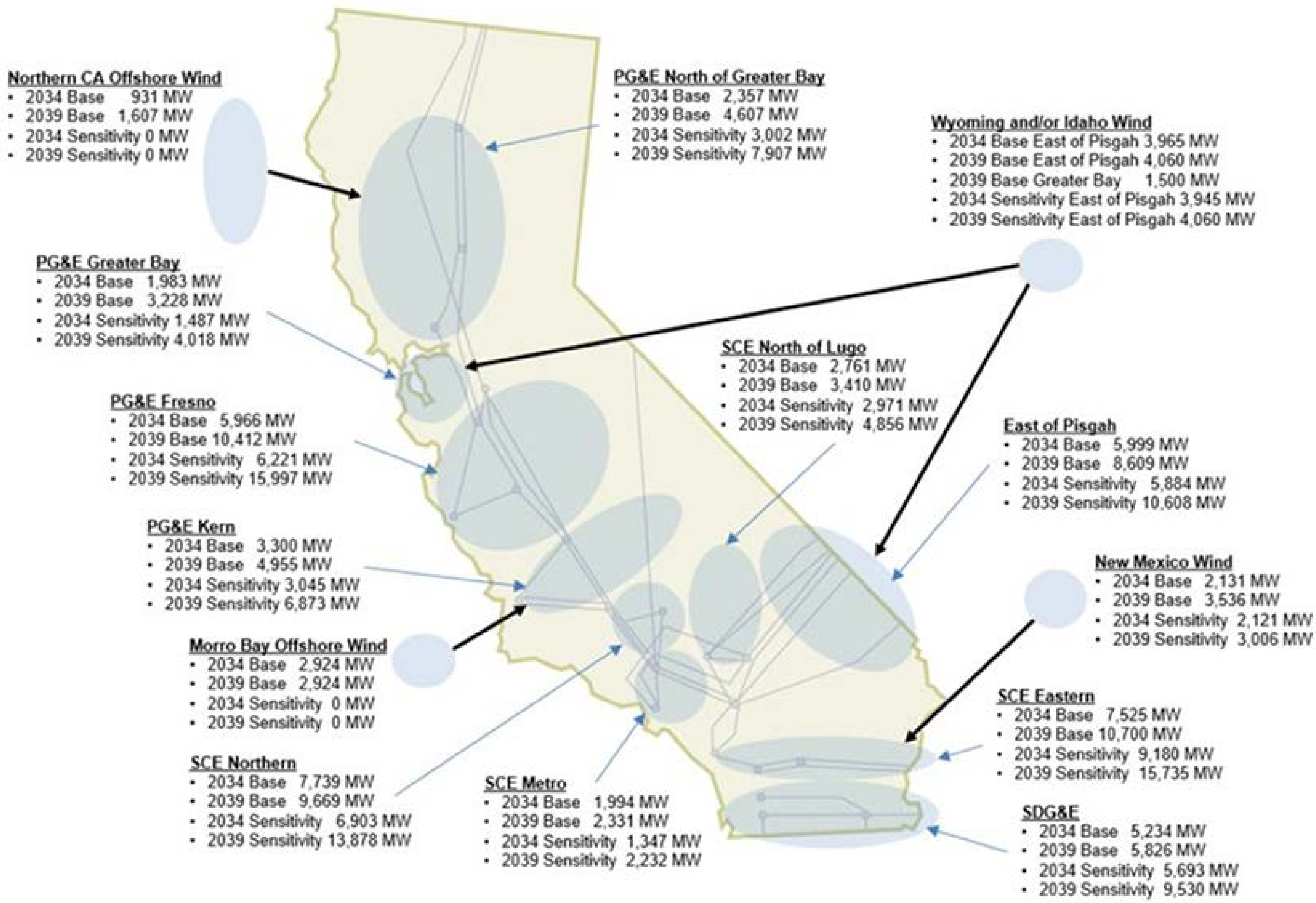
The new capacity needs include 30 GW of solar generation spread throughout the state, 7 GW of in-state wind resources in existing wind development regions, and more than 4.5 GW of offshore wind in the Morro Bay and Humboldt call areas.

The plan also factors in the need to import an additional 9 GW of wind energy from Idaho, Wyoming and New Mexico, which will require "enhancing corridors from the ISO border in southeastern Nevada and from western Arizona into California load centers."

Why This Matters

CAISO's transmission plan is a key component of California's effort to meet its aggressive renewable generation goals.

The plan additionally considers the transmission access needs of co-located battery storage projects across California, as well as for standalone projects close to major load centers in the Los Ange-



California transmission planning zones and capacity needs | *CAISO* les Basin, the Greater Bay Area and San Diego.

"Our draft plan reflects the ISO's proactive approach to transmission planning and underscores our ongoing collaboration with local, state and regional partners to ensure California has the necessary infrastructure to deliver clean energy reliably and cost effectively to consumers," Neil Millar, CAISO vice president for transmission planning and infrastructure development, said in a statement.

The ISO noted some of the projects would use grid-enhancing technologies.

Mostly Reliability

Twenty-eight reliability-driven projects account for nearly all the proposed spending, at roughly $4.56 billion.

"While the resource planning needs have not increased materially from those reflected in last year's transmission plan, the increased rate of load growth reflected in the most recent load forecast associated with building and other electrification, data center growth and transportation electrification results in significant reliability-driven needs in this year's transmission plan," the plan says.

The 2024/25 plan assumes the state's peak demand will increase at a 1.53% yearly rate, compared with a 0.99% forecasted growth rate in the previous plan. Peak demand in the Greater Bay Area is now expected to grow by 2.14% annually (up from 1.22%), translating into a 2,000-MW increase in the region's 2035 peak load forecast, "with most of the growth coming from electrification of the transportation and building sectors of the state's economy and an anticipated increase in data centers associated with artificial intelligence." (See *Data Centers Contribute to 60% Increase in San Jose Load Forecast*.)

The Bay Area would host the priciest reliability projects in the plan, including Pacific Gas and Electric's North Oakland ($1.13 billion) and Greater Bay 500-kV transmission ($700 million) reinforcement projects. San Diego Gas & Electric's Downtown Reliability reinforcement project comes in third at $500 million.

Three policy-driven projects would entail about $289.5 million in spending.

All three recommended policy projects are in PG&E's territory, including two in Fresno and one in the North Coast/North Bay local area. "They are needed to meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios," the ISO said.

CAISO said the plan identified no economically driven projects, representing those that would reduce costs for ratepayers but are not needed for reliability.

The ISO said the 31 recommended projects "represent significant investments that are phased in over lead times of up to eight to 10 years, which are reasonable for some of the projects to be completed."

Costs would translate into about 0.5 cents/kWh over the life of the projects and will be phased in as lines come into service, the ISO said.

CAISO will hold an April 15 public stakeholder call on the draft plan and is taking comments through April 29. The ISO's Board of Governors is expected to vote on the plan at its May meeting. ■

Newsom Issues Order to Speed Undergrounding of Lines in Los Angeles

Order Suspends Environmental Laws to Boost Recovery Efforts After Wildfires

By Henrik Nilsson

California Gov. Gavin Newsom has suspended environmental laws to accelerate the undergrounding and hardening of utility equipment in communities ravaged by the Los Angeles wildfires.

Newsom's executive order removes requirements under the California Environmental Quality Act and the California Coastal Act in an effort to speed up "the rebuilding of utility and telecommunication infrastructure, including the undergrounding of equipment," *according to a March 27 news release*.

A previous executive order similarly suspended the environmental laws and applied to infrastructure damaged in the wildfires. However, that order was limited, and projects to move equipment underground or upgrade existing infrastructure may not qualify under the previous suspension, the most recent *order* stated.

"We are determined to rebuild Altadena, Malibu and Pacific Palisades stronger and more resilient than before," Newsom said in a statement. "Speeding up the pace that we rebuild our utility systems will help get survivors back home faster and prevent future fires."

In a Feb. 27 letter, Newsom urged Southern California Edison and Los Angeles Department of Water and Power to develop plans by the end of March on how the utilities can rebuild safer and resilient electric infrastructure, including by placing electric distribution infrastructure underground.

Jeff Monford, a spokesperson for SCE, told *RTO Insider* the utility appreciates "Gov. Newsom's action to help expedite permitting so the fire-damaged communities can rebuild stronger. We look forward to continuing our work with federal, state and local officials to shorten permitting times under this executive order."

SCE already has launched efforts to underground several miles of lines in Altadena and Pacific Palisades, "and some sections of the grid will be completed in a few months," Monford said.

The Eaton Fire burned over 14,000 acres and destroyed thousands of homes. | *Shutterstock*

Why This Matters

Newsom's executive order is part of the effort to rebuild areas destroyed by the wildfires, and utilities will play a critical role in the recovery.

Monford would not share specific cost information but noted that undergrounding costs significantly more than building the grid with power poles.

"There's a lot going on in these burn areas, and the expedited permitting, siting and permitting that the governor's order will allow will certainly help move that along," he added.

Local utility Pasadena Water and Power, which operates in the Altadena region that was devastated following the Eaton fire, said in an email that "nothing in the orders change any policy direction and capital projects that we have planned."

The Eaton Fire began shortly after 6 p.m. Jan. 7 and burned more than 14,000 acres and killed 17 people. The deadly fire engulfed parts of the Altadena community, with thousands of structures either damaged or destroyed, according to Cal Fire.

The Pacific Palisades fire burned 23,448 acres, destroyed 6,837 structures and killed 12 people.

SCE faces several lawsuits, alleging the utility's lines started the Eaton fire. SCE has said it is investigating possible links between its equipment and the fire. (See *SCE Probes Link Between Equipment and Eaton Fire*.)

The utility previously acknowledged its equipment may have sparked the Hurst Fire, which burned roughly 799 acres and damaged two homes. There were no reports of fatalities or injuries associated with the fire. SCE said it is cooperating with a Los Angeles Fire Department investigation. ■

Industry Must Share Risk Over Nuclear-powered Data Centers, Experts Say

Experts Weighed in on Subject During Joint Spring CREPC-WIRAB Meeting

By Henrik Nilsson

LA JOLLA, Calif. — As the U.S. Department of Energy explores using federal land for data centers powered by nuclear energy, experts say public-private risk sharing will be crucial to making nuclear viable.

The DOE on April 3 issued a request for information related to developing data centers on federal land, with 16 potential sites identified as "uniquely positioned for rapid data center construction, including in-place energy infrastructure with the ability to fast-track permitting for new energy generation such as nuclear," *according to a news release*.

The issue of nuclear energy and data centers was also discussed in La Jolla, Calif., during the joint spring conference of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB) on April 4.

WECC's 2024 Western Assessment of Resource Adequacy (WARA) found that annual demand in the Western Interconnection will grow from 942 TWh in 2025 to 1,134 TWh in 2034. That 20.4% increase is more than four times the 4.5% growth rate from 2013 to 2022 and twice the 9.6% growth forecast in 2022 resource plans. (See *West to See 'Staggering' Load Growth, WECC Report Says*.)

WECC said large loads are a major factor in the rapid demand growth, including data centers, factories and cryptocurrency mining. Electrification also plays a role.

Notable Quote

'Some of the costs of these projects could be more than the market cap of some utilities,' according to Nate Hill, head of energy policy at Amazon. 'So, there's going to have to be risk sharing."

Three Mile Island nuclear power plant | *DOE*

While there is widespread support for nuclear energy, which holds the potential to supply large amounts of baseload emissions-free electricity, there is a need for risk sharing, especially in the beginning as the industry navigates costs, construction cycles, regulations and other challenges, said Marcus Nichol, executive director of new nuclear at the Nuclear Energy Institute.

"The utilities that might own and operate and build these, they're willing to take on some risk," Nichol said. "We're actively working with them to help reduce the risk so that it's more manageable. But they need help to be able to take this on."

Nichol noted that there are federal tax incentives in place, and U.S. Sen. Jim Risch (R-Idaho) introduced the Accelerating Reliable Capacity Act in December to accelerate investment in commercial nuclear projects by minimizing cost overrun risk.

States are also "looking at their own state-tailored policies to be able to help contribute to taking on some of the risk," Nichol said. Some data center developers are also looking to "contribute and take on some of the risk as well," Nichol added.

Meta, Microsoft and Amazon have all announced plans to power data centers with nuclear technology. (See *Meta Seeks Nuclear Partners; AWS Boosts Efficiency*.)

For example, Constellation Energy plans to reopen Three Mile Island Unit 1 under a power purchase agreement with Microsoft to sell about 835 MW to serve the company's data centers. (See *Constellation to Reopen, Rename Three Mile Island Unit 1*.)

Amazon, meanwhile, has committed $1 billion to early-stage development work, said Nate Hill, head of energy policy at Amazon.

"From Amazon's perspective, we're willing to put our capital at risk to help get some of these early-stage projects off the ground," Hill said. "Because, I mean, when you think about it, like some of the costs of these projects could be more than the market cap of some utilities. So, there's going to have to be risk sharing."

Katie Rogers, manager of reliability assessments at WECC, noted that the numbers could change as WECC learns more about how much of the demand will be realized.

Still, the industry must move toward holistic grid planning and share the burden, Rogers said.

"It feels very much like that we maybe need to have a different approach to how we plan the grid, and maybe not looking at, you know, one person carrying or one subset of people carrying all the risk if it has broader implications to the grid," Rogers said. "It needs to be looked at holistically with everything." ■

Asthana, Vegas to Headline ERCOT's Innovation Summit

ERCOT said April 2 that PJM CEO Manu Asthana will join its own CEO, Pablo Vegas, in opening the grid operator's second annual *Innovation Summit* on May 6 in Round Rock, Texas.

PJM CEO Manu Asthana (right) will join peer Pablo Vegas in opening the second annual ERCOT Innovation Summit. | © *RTO Insider*

The two chief executives will discuss how their organizations and others are adapting to and managing the complexities of "rapidly changing grids" in an opening "Energy Insights" conversation during the summit.

ERCOT said the summit will bring together leaders to share ideas and technology advancements and to collaborate on innovative solutions facing grid transformation in Texas and across the country.

The agenda includes ERCOT's grid-transformation initiatives and panels on data center interconnection, demand response, probabilistic planning methods and industry innovation in other ISOs and RTOs.

"I am excited to join colleagues at the Innovation Summit to explore how we can collectively maintain reliability during rapidly evolving industry dynamics," Asthana said in a *press release*.

Ballooning load from data centers has been at the heart of stakeholder discussions and capacity market redesigns at PJM in recent years. The RTO has made changes to its process for transmission owners to submit large load additions and is working with stakeholders to revise its effective load-carrying capability probabilistic modeling of the intersection between system risks and generation accreditation. (See *PJM Stakeholders Endorse Proposals to Rework ELCC Accreditation*.)

Registration closes April 18. ■

— Tom Kleckner and Devin Leith-Yessian

ISO-NE's van Welie Discusses Congressional Testimony with NEPOOL

By Jon Lamson

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

In a rare address to the NEPOOL Participants Committee on April 3, ISO-NE CEO Gordon van Welie discussed his recent testimony at the U.S. House Energy and Commerce Subcommittee on Energy, emphasizing the important role that states play to reduce price volatility in the wholesale markets.

Representatives of every ISO and RTO testified to Congress on March 25 about grid reliability. (See *All 7 ISO/RTOs Send Senior Executives to Update Congress on Reliability*.) Van Welie spoke about New England's pipeline constraints, the value of offshore wind and the importance of "alignment between federal and state policies."

Much of van Welie's time in Washington was spent responding to antagonistic questions about renewables. In his *written testimony* submitted to Congress and addressing the PC, van Welie stressed that markets alone cannot guarantee resource adequacy and urged the New England states to hedge against high market prices.

While ISO-NE's wholesale markets "are essentially short-term 'spot' markets," van Welie wrote, the states can enter long-term contracts "to protect consumers against undue price volatility in both the energy and capacity markets, and to incent the development of sufficient resources to meet the resource adequacy standard that is priced in the capacity market."

States have an important role in reducing the barriers to entry for new resources, he said. He acknowledged that recent federal policy changes — including antagonism towards offshore and onshore wind and new tariffs on imports — create significant challenges for renewable energy development.

"Over the past few weeks, we have seen firsthand the impact that shifts in federal policy can have on our region," van Welie wrote. "If the large amount of offshore wind that has been contracted for by the states is significantly delayed or ultimately does not materialize, the region would need to assess the potential impacts and determine what other options might be needed to meet resource adequacy needs in the future."

If the struggles of offshore wind development continue, the region could pursue an increase in the dual-fuel capabilities of its gas fleet, or an increase of its gas pipeline import capacity, van Welie said. However, he noted that increasing gas capacity into the region is likely not a short-term solution. Increased pipeline capacity would reduce the constraints that contribute to high gas prices in the region but would come at a significant upfront cost and could create risks of stranded costs as the New England states eye a long-term shift away from natural gas.

One stakeholder referenced a *2017 study* by Synapse Energy Economics that found a proposed Enbridge pipeline intended to reduce the region's gas constraints would cost about $6.6 billion, a price tag that would likely be significantly higher today, given the increased costs of large infrastructure projects.

Why This Matters

If offshore wind resources fail to materialize in the coming years, New England may need to look to other power sources to meet load growth and growing energy adequacy concerns, van Welie said.

Operations Report, Votes

Also at the PC meeting, ISO-NE COO Vamsi Chadalavada reported that energy market revenue totaled $456 million in March, up from $256 million in March 2024. The increase corresponded with significantly higher average natural gas prices compared to March 2024.

The monthly peak load was 17,200 MW, and there were no capacity deficiency events to report.

Power system emissions have *trended up* so far this year relative to 2024, largely because of lower temperatures across the region.

The committee voted to approve the *consent agenda*, which included tariff changes intended to improve its economic study process and changes to the ISO-NE operating procedure concerning protection outages settings and coordination.

It also approved a slate of three candidates for the ISO-NE Board of Directors. The slate now goes to the board for approval. ■

ISO-NE Releases Longer-term Transmission Planning RFP

By Jon Lamson

Why This Matters

If successful, the project will help facilitate renewable development in northern New England and will serve as an example for future transmission procurements to address long-term needs.

ISO-NE on March 31 *published* the request for proposals for its first longer-term transmission planning (LTTP) procurement, which is focused on increasing North-to-South transmission capacity in New England and interconnecting onshore wind resources in Northern Maine.

The RFP is the culmination of months of work between ISO-NE, the New England states and stakeholders from across the region, and it could set the precedent for future procurements to meet anticipated transmission needs. (See *FERC Approves New Pathway for New England Transmission Projects*.)

The main objectives and requirements of the RFP were established by the New England States Committee on Electricity (NESCOE) in December. (See *ISO-NE to Work on State-backed RFP for Northern Maine Transmission*.)

NESCOE defined the objectives as "strengthening the connection between northern and southern New England," and "facilitating the integration and deliverability of additional affordable generation resources located in Maine."

At a minimum, proposed projects must increase the transfer limit of the Maine-New Hampshire interface to 3,000 MW, the limit of the Surowiec-South interface to 3,200 MW and establish new infrastructure in Central Maine to facilitate the interconnection of 1,200 MW of onshore wind. The RTO wrote that applicants could propose upgrades that go beyond the minimum requirements.

The Maine-New Hampshire interface currently has a transfer limit of 2,000 MW, and the Surowiec-South interface has a limit of 1,800 MW.

"All three of these needs must be addressed by Dec. 31, 2035, unless a QTPS [qualified transmission project sponsor] respondent can demonstrate supply chain issues that warrant a later in-service date," ISO-NE wrote in the RFP.

The two interfaces were identified as high-likelihood concerns in ISO-NE's *2050 Transmission Study*. The focus on onshore wind is driven by its significant potential for low-cost renewable energy production in Northern Maine. (See *Long Road Still Ahead for Aroostook Transmission Project*.)

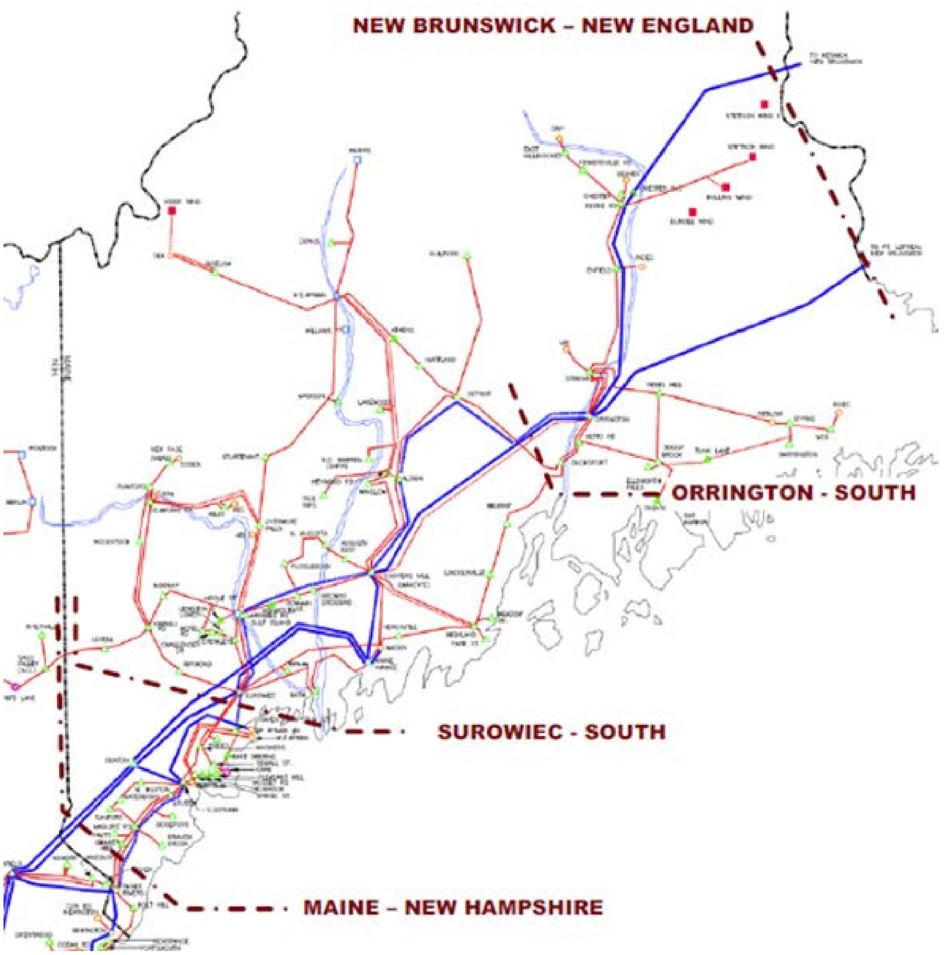
The deadline for project submissions is Sept. 30. ISO-NE expects to take about a year to evaluate proposals and select a preferred solution.

Applicants will be required to submit a $100,000 deposit, which will be used to cover study costs. Project sponsors can submit solo or joint proposals, but all proposals must be complete solutions. ISO-NE plans to publish a summary of every proposal received for the RFP.

The RTO wrote that project developers can include in their proposals "corollary upgrades" to infrastructure in the service territory of a different participating transmission owner (PTO).

"As part of the corollary upgrade, the PTO may install new facilities only to interconnect the QTPS respondent's longer-term proposal to the PTO's existing transmission system. Any other corollary upgrades must only be upgrades or replacements of existing facilities," ISO-NE wrote.

The RTO noted that corollary upgrades could include "reconductoring an existing line, rebuilding an existing line, rebuilding a single existing circuit in a double-circuit configuration … multiple-circuit tower separation, operating voltage changes or replacement of circuit breakers with higher-rated breakers."



ISO-NE-Maine interfaces | ISO-NE

Other than infrastructure to interconnect the project, applicants cannot propose new infrastructure in another TO's service territory without an agreement or joint proposal with the TO.

To screen proposals, ISO-NE will perform steady-state, stability and short-circuit analyses, as well as a transfer analysis "to confirm that the required minimum interface capabilities on the Maine-New Hampshire and Surowiec-South interfaces in the future year are met."

The RTO will also conduct energy and capacity tests to assess whether the solution will facilitate the required onshore wind interconnection.

If a project passes all the screening tests and meets all the requirements, ISO-NE will conduct a cost-benefit analysis, calculated based on "an independent capital cost estimate, using a consistent capital cost estimating methodology, to ensure consistency in its review of the longer-term proposals and their cost estimates."

To be eligible for selection, the cost-benefit analysis must show that the project would provide the region with net cost benefits. If no projects pass this threshold, one or more states could opt to cover the costs that exceed the benefits.

The analysis will include capacity expansion, production cost and resource adequacy models to calculate benefits, which it will evaluate over a 20-year period after a project's in-service date.

ISO-NE will also calculate the benefits of avoided transmission investments "based on the extent to which the project eliminates the need for projects already included on the [Regional System Plan] project list, replaces assets that are already planned to be replaced due to asset condition and included on the Asset Condition List, or replaces assets that are likely to be replaced due to equipment age."

For all projects that pass the cost-benefit threshold, ISO-NE will "holistically" consider both quantitative and qualitative factors to select the preferred solution. The highest-priority factors in this evaluation will include life-cycle costs, cost-containment provisions, permitting challenges, potential to interconnect additional resources and incorporate future needs, and impacts on system performance.

Lower-priority factors will include operational, environmental and winter reliability impacts, project constructability, and the use of advanced transmission technologies.

ISO-NE will present its preliminary preferred solution to the Planning Advisory Committee for feedback. After ISO-NE posts the preferred solution, NESCOE will have the opportunity to terminate the process or submit an alternative cost allocation methodology.

In a *press release*, Advanced Energy United wrote that the RFP "demonstrates that with the right planning and collaboration, we have the will and means to build the transmission infrastructure necessary to power a clean energy future," adding that "it is critical to ensure that this RFP results in well vetted, competitively sourced projects getting built quickly to bring net benefits to New England." ■

FERC Approves ISO-NE Order 2023 Interconnection Proposal

Ruling Comes After Months of Waiting for New England Stakeholders

By Jon Lamson

Why This Matters

The new interconnection rules will overhaul how ISO-NE processes interconnection requests, and are intended to address significant interconnection backlogs in the region.

FERC has accepted ISO-NE's compliance proposal for Order 2023, setting the stage for sweeping changes to the RTO's interconnection procedures.

The April 4 ruling came nearly eight months after ISO-NE's proposed effective date of Aug. 12, 2024, and followed months of stakeholder requests for rapid action to preserve the transition timeline and prevent significant delays to projects in the interconnection queue (*ER24-2009, ER24-2007*).

FERC's ruling largely accepted ISO-NE's proposal but directed the RTO to make relatively minor changes in an additional filing.

Order 2023 and the follow-up ruling, Order 2023-A, require transmission providers to transition from serial interconnection processes to cluster study processes, in which interconnection requests will be studied simultaneously.

ISO-NE filed its Order 2023 compliance proposal in May 2024 with the support of NEPOOL after an extensive process of stakeholder engagement and revisions. (See *NEPOOL PC Backs ISO-NE Tariff Revisions for Order 2023 Compliance* and *ISO-NE Order 2023 Compliance Proposal Fails to Pass NEPOOL TC*.)

In comments submitted to FERC, developers generally supported the filing, though several groups requested changes, such as a shorter cluster study timeline and reduced study deposit requirements. (See *Clean Energy Groups Respond to ISO-NE Order 2023 Filing*.)

Allco Finance had urged the commission to reject the proposal due to impacts it would have on distribution-level projects and argued that ISO-NE does not have jurisdiction over state-level interconnection procedures. But FERC ruled that the complaint was outside the scope of the proceeding, finding the company had not demonstrated ISO-NE failed to comply with Order 2023 or Order 2023-A.

Despite arguments from some stakeholders that ISO-NE should adopt the 150-day cluster study timeline outlined by Order 2023, the commission accepted the RTO's proposal for a 270-day process. ISO-NE said a 150-day timeline would be infeasible for the region.

FERC agreed that the 270-day timeline "reflects ISO-NE's unique regional issues and the comprehensive scope of its studies, including electromagnetic transient studies for inverter-based resources."

The commission also approved ISO-NE's proposal to reduce the cluster restudy timeline from 150 to 90 days, noting the RTO "will use the same base case data as the cluster study and will involve fewer interconnection requests, thereby allowing interconnection requests to proceed expeditiously through the interconnection study process."

FERC also accepted ISO-NE's proposal to require a flat $250,000 deposit and a $50,000 application fee for the cluster study, writing that "extending the $250,000 deposit to smaller generators is reasonable due to regional differences because … project size is not a ready indicator of study cost or complexity for interconnection requests in New England."

It rejected arguments by Glenvale Solar that ISO-NE's proposed deposit requirements are prohibitive for smaller projects participating in the process, saying the "proposed flat deposit structure reasonably approximates study costs in New England."

The commission also approved ISO-NE's proposal for a $500,000 initial commercial readiness deposit, writing that the amount will help deter speculative interconnection requests. Order 2023 requires commercial readiness deposits to be twice the size of study deposits.

"While higher than the pro forma [Large Generator Interconnection Procedures], we find the variation is justified because the $500,000 amount reflects historically high network upgrade costs in ISO-NE," FERC wrote.

Optimism Around Transitional CNR Study

FERC additionally accepted ISO-NE's initial prohibition of using surety bonds for deposits, despite Order 2023's direction to do so, saying the RTO demonstrated it needs more time to develop the procedures for accepting the bonds. The order directed the RTO to submit additional information about when it will begin accepting surety bonds for commercial readiness and study deposits.

ISO-NE's transition process for adopting the changes also largely complies with Order 2023, FERC wrote. The commission wrote that the creation of a transitional capacity network resource (CNR) group study helps to appropriately balance "the need to move expeditiously to the new cluster study process with the need to respect the investments and expectations of interconnection customers at an advanced stage in the existing interconnection process."

The transitional CNR group study is intended to allow projects with complete system impact studies to gain capacity interconnection rights without needing to go through the full cluster study. Going forward, interconnection customers will achieve capacity interconnection rights through the cluster studies.

In recent months, project developers have raised alarms that FERC's inaction on ISO-NE's compliance proposal could threaten the ability to align the transitional CNR study with the qualification activities for ISO-NE's 2025 reconfiguration auction (RA). (See *New England Generators Remain in Limbo on Interconnection Reform*.)

ISO-NE had said it would need a ruling by March 31 to align the transitional CNR group study with the 2025 RA qualification process due to a show-of-interest submission deadline at the end of April. On March 31, FERC took the unusual step of informing ISO-NE and stakeholders that it planned to issue an order in the coming days. (See *FERC Announces Impending Order on ISO-NE Order 2023 Compliance.*)

Alex Lawton of Advanced Energy United, who has been vocal about the importance of the transitional CNR study, said he is optimistic that FERC's ruling will enable ISO-NE to proceed with the study.

A representative of ISO-NE said the RTO "is reviewing the April 4, 2025, order in detail and assessing next steps."

The ruling also accepted independent entity variations related to site control requirements, the opportunity to reduce project size prior to a cluster restudy, energy storage modeling and the evaluation of alternative transmission technologies.

FERC directed ISO-NE to make a series of relatively minor changes to its proposal within 60 days, including to correct multiple "unexplained deviations" from the *pro forma* language, and to add *pro forma* language that was omitted. The commission also found the proposal did not comply with Order 2023's ride-through requirements.

The commission accepted ISO-NE's proposed Aug. 12, 2024, effective date and the June 13, 2024, deadline for interconnection customers to have a valid interconnection request to be eligible to participate in the first cluster study. While the RTO briefly reopened its interconnection queue April 1, requests submitted after this date will not be eligible to participate in the transitional cluster study. (See *ISO-NE to Reopen Queue as it Continues to Wait on Ruling from FERC*.) ■

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Holtec's Palisades Restart Fends off Challenge from Anti-nuclear Groups

By Amanda Durish Cook

Palisades' Westinghouse turbine generator around the time Entergy closed it in 2022 | *Entergy*

The planned restart of the Palisades Nuclear Plant survived a challenge from anti-nuclear organizations March 31, with a panel of judges of the U.S. Nuclear Regulatory Commission deeming their arguments inadmissible.

The three judges on the NRC's Atomic Safety and Licensing Board Panel declined to grant a hearing to a coalition of anti-nuclear groups: Beyond Nuclear, Don't Waste Michigan, Michigan Safe Energy Future, Three Mile Island Alert and Nuclear Energy Information Service.

The panel said the coalition's arguments against steps to resurrect southwest Michigan's Palisades either lacked factual support or were outside what the NRC was specifically considering for the plant (*50-255-LA-3*). The groups sought to dispute an exemption and amendments that owner Holtec International first sought from the NRC in 2023.

To restore Palisades, Holtec needs an exemption on the permanent reactor shutdown certifications granted to the previous owner, Entergy, as it was closing the plant in 2022. The certifications prohibit operation of the reactor or placement of fuel into the reactor vessel. Additionally, Holtec needs four license amendments that will allow it to refuel the plant and restart operations as early as fall 2025. The quartet of amendments would alter technical specifications, revise an emergency plan to support the return of operations and update the methodology for studying the potential consequences of a main steam line rupture.

What's Next?

Beyond Nuclear and other anti-nuclear groups have vowed to continue fighting the planned reopening of Holtec's Palisades Nuclear Plant using other avenues after the Atomic Safety and Licensing Board declined their request for a hearing.

Beyond Nuclear and others entered a request for hearing of Holtec's exemption and amendment requests in February. (See *Anti-nuclear Groups Challenge Palisades Reopening*.)

But the panel said the groups and their experts made "bald assertions" about the safety of the plant, the time and costs of repairs, and Holtec's supposed inexperience with nuclear operations. The judges said the groups' claims that a restart would not be in the public interest "are conclusory and speculative."

They also said the groups' demand that Holtec obtain a new operating license for Palisades and a fresh environmental impact statement were beyond the scope of the hearing request. The groups had said that Holtec should not be able to seek amendments or exemptions on the existing operating license because it no longer allows reactor operations or fuel in the reactor vessel.

"The commission has determined that restart requests will be evaluated using the agency's existing regulatory framework, which provides for license amendment requests and requests for exemptions from regulations," the judges said. "Therefore … claims that applicants' operating license may not be amended or that applicants may not seek exemptions from regulations amount to an impermissible challenge to agency policy and regulations."

On the matter of requiring an EIS, the judges said the groups merely speculated as to what environmental harms may occur from resurrecting a partly decommissioned plant.

The judges rejected the groups' criticism that the NRC is "cobbling together" a restart authorization because it has no dedicated regulatory procedure for restarting a closed reactor. The judges decided their argument is inadmissible because it "challenges NRC regulations and policy, relies on conclusory and speculative claims, and does not otherwise raise a specific challenge to the four license amendment requests that are the subject of this proceeding."

The groups contended Holtec should not get a license exemption under hardship provisions because the company knowingly entered "a difficult situation of its own making" by buying a plant entering decommissioning and then pursuing a restart. They also said Holtec did not prove its restart activities should be categorized under special circumstances that should earn a deviation from normal rules.

But the panel decided those arguments were vague and did not see how they supported denying the exemption request.

The judges did not terminate the proceeding because the anti-nuclear coalition has put forward more challenges to the NRC's environmental assessment of Palisades.

Groups Keep Sounding Safety Alarm

However, the groups said they were ready to appeal the decision and go to court over the state of Palisades steam generator tubes, which they say are degraded.

Arnie Gundersen, an engineer at anti-nuclear nonprofit Fairewinds Energy Education and an expert witness for the coalition who testified at the pre-hearing trial, maintains that the Palisades steam generators have formed stress corrosion cracks.

"During my 53 years of professional experience, I am unaware of any steam generator, with so many previously known and newly identified flaws, that has not been replaced," he said in a press release following the panel's decision. Gundersen added that he had "never been more concerned about the safety of a nuclear power plant."

The groups contend that Palisades' original owner, CMS Energy, told the Michigan Public Service Commission in 2006 that the steam generators *needed* replacing. Entergy did not pursue replacements during operations from 2007 to 2022 because the NRC did not require it, the groups said. Holtec estimated in 2022 that steam generator replacements would cost about $510 million.

"The Japanese parliament concluded that the root cause of the Fukushima Daiichi nuclear catastrophe of 2011 was *collusion* between the safety regulator, Tokyo Electric and government officials," Beyond Nuclear's Kevin Kamps said in the same press release. "There is such potentially catastrophic collusion in spades at Palisades, between the ASLB and NRC, Holtec and government officials here. The entire Great Lakes region is being put at risk."

Meanwhile, Holtec's progress on Palisades continues on other fronts. On March 17, U.S. Energy Secretary Chris Wright *announced* a $56.8 million loan disbursement for Holtec, the second part of the Department of Energy's $1.52 billion in loan guarantee for Palisades. ■

FERC Approves Increase in MISO Value of Lost Load to $10K

By Amanda Durish Cook

FERC on April 4 gave MISO the go-ahead to set its value of lost load (VOLL) at $10,000/MWh by early fall, nearly three times as high as the current $3,500/MWh value (*ER25-579*).

The new VOLL can take effect Sept. 30, FERC said. It would be used as a price cap for locational marginal prices and market clearing prices during load-shedding events.

In the same order, FERC also greenlit changes to MISO's operating reserve demand curve (ORDC), which establishes shortage pricing and is linked to the VOLL.

Though it can implement the $10,000 VOLL in load shedding, MISO proposed its ORDC peak at a lower, $6,000 VOLL and stay there until about 50% of cleared operating reserves materialize. From there, the curve will slope downward until MISO can confirm more than 80% of cleared operating reserves, at which point the curve becomes two steps: $1,100/MWh until 88% of reserves show up, and $600/MWh until 100%.

MISO's current curve sits mostly at $1,100/MWh and $2,100/MWh across two large, flat steps before it tops out at $3,500/MWh.

The commission decided it was appropriate that MISO be allowed to use two VOLLs, one to set the ORDC and one to estimate the financial blow of shedding load across all customer classes. It said the higher VOLL and more nuanced ORDC "will give market participants efficient financial incentives to respond to scarcity and shortage conditions and act in ways that support system reliability in MISO by either increasing supply or reducing demand."

Why This Matters

MISO has said for more than a year that its circa-2007 $3,500/MWh VOLL is too cheap to reflect its customers' willingness to pay. After September, the RTO can hike the value to $10,000/MWh.

MISO proposed the steeper VOLL at the beginning of 2024; staff said the too-modest $3,500/MWh was set in 2007 and is outdated, no longer reflecting the threshold of customers' willingness to pay. (See *MISO to Limit Use of $10K VOLL During Long-duration Outages*.)

MISO's Chuck Hansen has said in stakeholder meetings that $10,000/MWh is "a low-end estimate of the negative financial impacts associated with MISO-directed firm load shedding." He pointed out that MISO has only directed load shedding once in the past 17 years, ordering about 700 MW offline in MISO South during February 2021's Winter Storm Uri.

While explaining MISO's filing to the Market Subcommittee in August 2024, Hansen said MISO "qualitatively" expects the higher scarcity price ceiling to make loss-of-load events rarer and shorter lived, as members are motivated to reduce consumption. He likened a higher VOLL to police using tickets to deter speeding.

"If the speeding ticket is $2, who cares? If the speeding ticket is $200, well, that's different. It needs to be high enough that some demand does not want to pay that much," Hansen said.

The commission dismissed Cooperative Energy's criticism that MISO's capacity auction already delivers revenues that incent new generation builds. The Mississippi cooperative said a higher VOLL would "add a reactive and punitive component to the market design."

FERC countered that the VOLL is a needed indicator of when to build.

"While an appropriate VOLL does guide investment and retirement decisions in the long term, we emphasize that shortage price signals in the day-ahead and real-time markets, which are developed through the VOLL and ORDC, are also near-term signals to incent real-time actions by generation and demand resources during [or before] the operating day … to avoid potential shortage conditions," FERC said.

An Entergy Arkansas downed tower on April 3, after severe storms. The extreme weather did not trigger load shed. | *Entergy Arkansas*

Finally, FERC said the so-called "circuit breaker" that MISO worked into its VOLL design should assuage Cooperative's fears that the higher value could bankrupt utilities and strain customers' pocketbooks. The circuit breaker refers to MISO sequentially lowering VOLL during extended load-shedding events.

MISO plans to cut the VOLL in half to $5,000/MWh after four hours of firm load shedding during a maximum generation emergency. When active load-shedding measures are not lifted in time for MISO's 10:30 a.m. ET day-ahead market closing, the RTO will extend the lower, $5,000/MWh VOLL into the next operating day. For load shedding that continues into a second day and beyond, MISO will slash its day-ahead and real-time VOLL to $2,000/MWh for successive operating days.

The $2,000/MWh step can continue indefinitely until the maximum generation emergency is terminated and normal operations resume. RTO staff chose the $2,000/MWh amount partly because it is the hard cap on incremental energy offers, as dictated by FERC Order 831. MISO said it wanted to limit prices for extreme, dayslong outage events.

"MISO's proposal strikes a reasonable balance by more accurately reflecting load's willingness to pay and by providing protection to consumers by limiting the duration of their exposure to higher prices that could result from its proposal," FERC wrote. ■

TVA Board Promotes Nuclear Veteran from COO to CEO

By Amanda Durish Cook

The Tennessee Valley Authority board of directors announced it will elevate COO Don Moul to become the fourth CEO of the federal utility.

The promotion further positions TVA for a nuclear-dominant future. Moul previously served as a chief nuclear officer and senior nuclear reactor operator, among other primarily nuclear roles at American Electric Power, Duquesne Light Co., FirstEnergy, GPU Nuclear Corp. and Public Service Electric & Gas.

Moul, who has 38 years of experience in the power industry, replaces outgoing CEO Jeff Lyash, who also has an extensive background in nuclear operations. (See *TVA CEO Jeff Lyash Announces Plans to Retire*.) The appointment becomes effective April 9 and makes Moul the second TVA COO to earn a CEO promotion. TVA's first CEO, Tom Kilgore, also was COO before Congress established the CEO position in 2005.

Before joining TVA in mid-2021, Moul was executive vice president and chief nuclear officer at NextEra Energy, where he oversaw operations at seven units as well as decommissioning of the Duane Arnold Energy Center.

Announcement After Senator Criticism, Board Member Dismissal

Moul's advancement follows Sens. Marsha Blackburn and Bill Hagerty, both Republicans of Tennessee, authoring a March 20 *op-ed* in *POWER Magazine* calling for the next TVA leader to lead the "nation's nuclear energy revival" and fall in step with President Donald Trump's vision for more nuclear power.

Don Moul | *TVA*

The senators criticized the utility's leadership and board for moving too slowly on nuclear development and said they were concerned "TVA's next CEO would be hired from within."

TVA holds the country's only early site permit for small modular reactor (SMR) construction at its Clinch River Nuclear Site in Oak Ridge, Tenn. U.S. Energy Secretary Chris Wright and Hagerty *toured* the site in mid-March. While TVA's board authorized $350 million in 2024 to explore nuclear solutions, it has not yet voted to approve an SMR at the site. Lyash has said TVA eventually aims to build a fleet of SMRs in its footprint.

"The presidentially appointed, Senate-confirmed, TVA board of directors lacks the talent, experience and gravitas to meet a challenge that clearly requires visionary industrial leaders. The group looks more like a collection of political operatives than visionary industrial leaders," Blackburn and Hagerty wrote.

A week later, TVA board member L. Michelle Moore, an appointee of former President Joe Biden, was fired at the direction of Trump, according to a Securities and Exchange Commission *report*. The Trump administration has not provided a reason for Moore's termination. In a statement, TVA said its board members serve at the pleasure of the president.

Moore's term would have expired on May 18, 2026. The Southern Alliance for Clean Energy called the firing a "hyper-partisan action."

The board currently has five members and four vacancies.

TVA Underscores Nuclear in Announcement

In a press release on Moul's hiring, TVA focused on its nuclear advancements. It said under Moul's leadership, "TVA is a national leader in driving advanced nuclear technologies forward."

"Don is ready to be the hand guiding TVA in a time of rapid change and growth, and he will continue to propel TVA's nuclear leadership," Lyash said. "In his role as COO, he has led the development of next-generation nuclear technologies and has a deep knowledge and appreciation for nuclear power — the most reliable power the world's ever known." Lyash also said TVA hired Moul four years ago "with succession planning in mind."

> **Why This Matters**
>
> COO Don Moul will become TVA's next CEO amid tensions over the federal utility's ability to lead a nuclear revival.

Moul said he expected his transition to be "seamless" for TVA.

"We're in a period of growth like we've not seen before, and to meet that growth, we are making one of the largest capital investments in our history," Moul said. "TVA needs a steady hand right now. I will build on the momentum that Jeff and our team have created — making sure we continue to invest in new generation, strengthen our grid and enhance system reliability."

Moul told the *Knoxville News Sentinel* the board conducted an internal and external search for a new CEO before they offered him the job after a series of interviews. TVA confirmed that the offer was extended on March 25 and predated Moore's termination.

Board Chair Joe Ritch said the board search was exhaustive.

"The TVA board took a structured, deliberative approach to CEO succession — evaluating a strong slate of both internal and external candidates," Ritch said in a statement to *RTO Insider*. "The board evaluated multiple search firms, reviewing in detail their process for candidate identification and assessment, ultimately selecting a firm with deep experience and expertise in the energy industry. The board also leveraged a third-party leadership assessment firm and an independent compensation consultant."

Lyash is set to retire as the highest-paid federal employee, making $10.5 million in total compensation over 2024. ■

NY Floats Initial Grid of the Future Plan

State Regulators Seek to Smooth Integration of Flexible Resources

By John Cropley

New York on March 31 issued the first iteration of a plan to move the state toward greater use of flexible resources to meet future power needs while preserving reliability and affordability.

The plan is part of the Grid of the Future proceeding (Case *24-E-0165*) initiated by the Public Service Commission in April 2024. (See *NY PSC Launches Grid of the Future Proceeding*.) It is intended to guide development of a more expansive process for distributed system implementation plans (DSIPs) prepared by the six investor-owned utilities as they implement a distributed system platform (DSP). The second iteration of the plan is expected by the end of this year.

Earlier this year, as part of the same effort, Volumes 1 and 2 of the Grid Flexibility Study prepared by The Brattle Group were released by the Department of Public Service and New York State Energy Research and Development Authority. (See *Study Finds Considerable 'Grid Flexibility' Potential in New York*.)

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The *First Iteration of the Grid of the Future Plan* was prepared by DNV Energy Insights USA and was released along with Volume 3 of Brattle's Grid Flexibility Study, which provides supplemental analysis.

A central goal of the Grid of the Future proceeding is to meet the state's ambitious clean energy goals at a manageable cost while maintaining system reliability. Flexible solutions such as distributed energy resources and virtual power plants are potential means to accomplish this.

The plan seeks to develop a DSIP process better aligned with the Grid of the Future proceeding, and to provide short- and long-term recommendations to ensure that DSIP filings are aligned with the state's 2030 and 2040 goals.

After a series of reviews, DNV offered several conclusions:

- The DSIPs as currently prepared do not provide outcome- or goal-oriented information and do not contain clear objectives or metrics, so it is difficult to assess whether a utility is progressing toward a functional DSP.
- Reporting, detail and organization are inconsistent among the DSIPs, and some answers to complex questions are incomplete; collective action among the utilities resulted in more comprehensive answers.
- New York's regulatory environment is not an undue obstacle to development of a DSP; instead, the most significant headwinds are grid investment costs and market design, which hinder efficiency and slow adoption. The most significant tailwinds are data access and standardized interconnection requirements.
- Some of the capabilities critical to a DSP are fully deployed and integrated but many have not been automated, are not well-integrated or are not deployed utility-wide.

DNV offered recommendations along the themes of reorganization, clarity and standardization:

Why This Matters

A central goal of the plan is to meet the state's ambitious clean energy goals at a manageable cost while maintaining system reliability.

- Department of Public Service staff should clarify their guidance to utilities to elicit clearer and more consistent responses, and to reduce the inconsistencies between DSIPs.
- Multipronged questions should be eliminated; content organization should be prescribed; and explicit expectations about answers should be offered.
- Technical topic areas can be further streamlined and reorganized to better reflect the evolving needs of a DSP.

DNV also offered recommendations to transform the DSIP process from a regulatory check-in to a strategic tool to guide utilities, regulators and stakeholders:

- Future versions of the DSIPs could focus on the value and intended outcomes of the processes and activities rather than just documenting them, and could include specific metrics to track progress.
- More detailed and streamlined guidance that includes standardized templates and metrics would make DSIPs more consistent and digestible, as well as easier to compare.
- Addressing gaps identified by the capabilities in the DSP framework will ensure DSIPs are comprehensive; including a focus on market design and implementation will allow reporting on grid edge capabilities.

The authors expect the Second Iteration of the Grid of the Future Plan to provide more specific recommendations. It is due to be released by Dec. 31, although the First Iteration and the Grid Flexibility Study both were delivered after their original target dates. ■

Demand Curve Reset Tops NYISO Priorities in Capacity Market Review

ISO Considering Reliability-based Pricing, Zone Redesign

By Vincent Gabrielle

After months of conversations with stakeholders, NYISO presented the Installed Capacity Working Group with its priorities for the *Capacity Market Structure Review* in an all-day meeting April 1, with improving the demand curve reset (DCR) process and methodology topping the list.

Also on the list are winter reliability capacity enhancements; attribute-based pricing for transmission security; improving capacity accreditation and resource adequacy modeling; and redesigning the capacity zones.

Of the listed priorities, the winter reliability enhancements are ongoing as a standalone project. Brendan Long, capacity market design specialist for NYISO, said they were occurring in parallel with the review.

Much of the morning was dominated by conversation about how NYISO would reexamine the DCR, the process by which it sets the proxy unit's cost of new entry into the market, which in turn helps set capacity prices for the next four years. The ISO just completed the most recent reset in 2024.

"This effort would look to examine alternative methodologies and processes for establishing the ICAP demand curves with the goal of reducing the complexity and resource intensity of the DCR," said Maddy Mohrman, senior market design specialist with NYISO.

Mohrman said this could include changing the demand curve shape and slope, using "empirical net cost of new entry" to set a reference price and leveraging existing publications of resource costs. But before she could proceed into detail on the ISO's options, stakeholders immediately began asking for things to be included under the scope of the DCR review. A representative of the Long Island Power Authority asked that examining the definition of the proxy unit be included. Another stakeholder asked whether the ISO would consider adding the annual update process.

Mohrman said the ISO could look at the proxy unit definition and that the annual update process was something it would be examining as part of the review regardless.

"Nothing's really off the table for this," she said. "We just want to highlight some of the alternatives we've already identified."

Leveraging Outside Cost Estimates

Currently the ISO hires a consultant to estimate the capital costs of each potential type of peaker plant using bottom-up engineering assessments. The assumptions used for those assessments have historically been the subject of considerable stakeholder debate. Rather than go through that process every four years, the ISO would use peaker plant cost estimates developed by external entities.

"Two organizations we could look to potentially leverage are [the National Renewable Energy Laboratory] and the [U.S. Energy Information Administration]," Mohrman said. "They regularly publish estimates of capital costs. We're looking into that further, and that could also be used, potentially, to help the annual update process as well."

Howard Fromer of Bayonne Energy Center said the capital costs in New York are very different from national estimates and that costs within the state vary significantly by region. Using estimates that don't capture New York's realities could generate an inaccurate CONE.

Mark Younger of Hudson Energy Economics said that using external sources could waste time and effort if ISO staff ended up having to substantially adjust the external cost estimates to make them fit in New York.

Is the Demand Curve Working?

Several stakeholders questioned whether the demand curve and the CONE were appropriate market mechanisms at all. One stakeholder argued that the demand curve mechanism only worked to incentivize capacity retention and buildout if prices continued to rise. Another stakeholder representing New York City said that if the market is designed only to function upward, then it isn't a market because it would incentivize overpaying and not price correction.

A third stakeholder, representing the transmission sector, said that in the past, the high price signals sent by the ICAP market would have incentivized new builds and eventual price competition. Currently, the price signal is high, but the vast majority of new generation is being built through state-level processes.

"We don't have confidence that new entry will occur outside of [renewable energy certificates] and state-sponsored resources, and we don't know what the accreditation factor change on those resources will be," they said. "High prices could be sustained without a true competitive process capable of disciplining them. We need to make sure we don't end up in that conundrum."

Mohrman steered the discussion back to NYISO's proposed solutions. She said the ISO was considering changing the shape of the demand curve. The curve has been linear since it was put in place in 2003.

"Alternative shapes and slopes may more accurately value resources according to their contribution to reliability, compared to this linear curve," she said. "This may also address some stakeholder concerns that the current demand curve structure may result in wealth transfers to incumbent resources."

Younger said that going with a steeper curve would result in more uncertain revenues and could possibly result in out-of-market actions, which may increase risk. Another stakeholder agreed, saying

Why This Matters

NYISO is in the early stages of overhauling its capacity market.

the steeper the curve, the greater price volatility.

Reliability Attribute-based Capacity Pricing

Michael Ferrari, a market design specialist for NYISO, took over to present the ISO's proposal for valuing resources' contributions to reliability via transmission security. He said the ISO is open to calculating separate resource adequacy and transmission security requirements for each locality, which would be traded separately as two different ICAP market products. This might mean creating a transmission security demand curve, transmission security capacity accreditation methods and new auction structures to solve both products.

"Potentially, as a secondary effort, we could leverage a framework to co-optimize with additional attributes in addition to transmission security," Ferrari said. "These attributes may include … ramping inertia, voltage stability and quick cycling."

Ferrari said NYISO would work with stakeholders to identify which additional attributes could be co-optimized with the ICAP market. He said it was possible that some attributes would be inappropriate and not work well as part of the market.

He said the purpose of all of this was to build more support for system reliability into the market.

Rezoning

NYISO divides New York into 11 capacity zones, labeled A to K approximately northwest to southeast. A is the Buffalo area, while J and K are New York City and Long Island, respectively.

The ISO wants to explore alternate ways to determine zone boundaries. This might mean exploring alternatives to the "*New Capacity Zone*" study, which examined deliverability across major transmission interfaces using a static set of system assumptions and conditions. The ISO is considering a probabilistic approach to identify system constraints and set zone boundaries.

The ISO is also considering increasing how frequently new zones can be considered for addition. The ISO lacks a mechanism to remove a zone and would explore whether having such a mechanism would improve price signals. ■

| HDR Inc.

Data Center Campus with up to 4.5 GW of Gas Generation Planned for Pa.

Facility Would Stand on Former Site of Large Coal Plant, Link with PJM and NYISO

By John Cropley and Devin Leith-Yessian

A data center campus planned in western Pennsylvania would include up to 4.5 GW of on-site gas-fired generation and be the largest facility of its kind in the U.S., a group of developers *announced* April 2.

The 3,200-acre Homer City project would stand on the site of what had been Pennsylvania's largest coal-fired plant, a 1.88-GW facility decommissioned in 2023.

The effort brings together GE Vernova, Kiewit Power Constructors and Knighthead Capital Management. It carries a price tag expected to surpass $10 billion — not counting the data centers themselves, which would cost billions more.

Homer City Redevelopment (HCR), which is leading the effort to restore the site to economic productivity, said it would be the largest investment of its kind in state history and is expected to start producing power by 2027.

HCR indicated that many of the components already are procured for the project, limiting the chances of supply-chain delays. GE Vernova will deliver the first of seven hydrogen-enabled gas-fired turbines in 2026, for example. And critical infrastructure remains in place from the coal-burning plant, including transmission lines to the PJM and NYISO grids, substations and water access.

There also is the nearby Marcellus Shale formation, one of the most productive U.S. sources of natural gas. Pennsylvania is the No. 2 gas producer in the U.S., after Texas.

Not discussed in the announcement is the typically slow pace of interconnection and the controversy surrounding co-located large loads.

"We are fully aware of the project and recently met with the developers," a FirstEnergy spokesperson told *RTO Insider*. "We are working closely with them to determine the necessary steps and milestones for them to move ahead with their plans for the site. FirstEnergy is committed to helping to improve the economies of the communities we serve, and we are eager to work collaboratively with the right parties to achieve their visions."

A spokesperson said PJM could not comment in detail without seeing more specifics. New resources are important in an era of increasing demand and tightening supply, they said, and the Homer City proposal would be well situated.

Comeback Planned

When it was built in 1969, the Homer City Generating Station became a physical and economic standout in the rural region 40 miles east of Pittsburgh, providing jobs and boasting a smokestack variously described as the tallest in the state or in the U.S.

But it ran into *regulatory and financial problems* as coal-fired generation fell out of favor, and it finally shut down July 1, 2023. The smokestacks and cooling towers recently were leveled with explosives.

The gap of years between shutdown of the old plant and startup of the new plant may factor into the interconnection process. Generation owners can request the capacity interconnection rights held by a retiring resource be transferred to another queue project for up to one year after the unit shutters. That window already has closed.

The other pathway for new projects to make their way quickly through PJM's interconnection queue would be by participating in the RTO's one-off Reliability Resource Initiative, which will allow 50 projects to be added to the Transition Cycle 2 study cluster. PJM said in March that it had received 94 applications for the program and will winnow those down to 50 based on several characteristics, including nameplate capacity, in-service date and location.

Meanwhile, the PJM spokesperson said the issues surrounding large-load co-location await clarification by FERC. PJM recently submitted comments to FERC in the matter in which it expressed reservations about large co-located load configurations participating behind the meter (*EL25-49*). (See *PJM Responds to FERC Co-located Load Investigation*.)

The RTO said its BTM rules were designed for smaller configurations, such as warehouses with on-site solar generation. PJM proposed several configurations that are permissible under the current rules while floating others the commission could consider exploring. ■

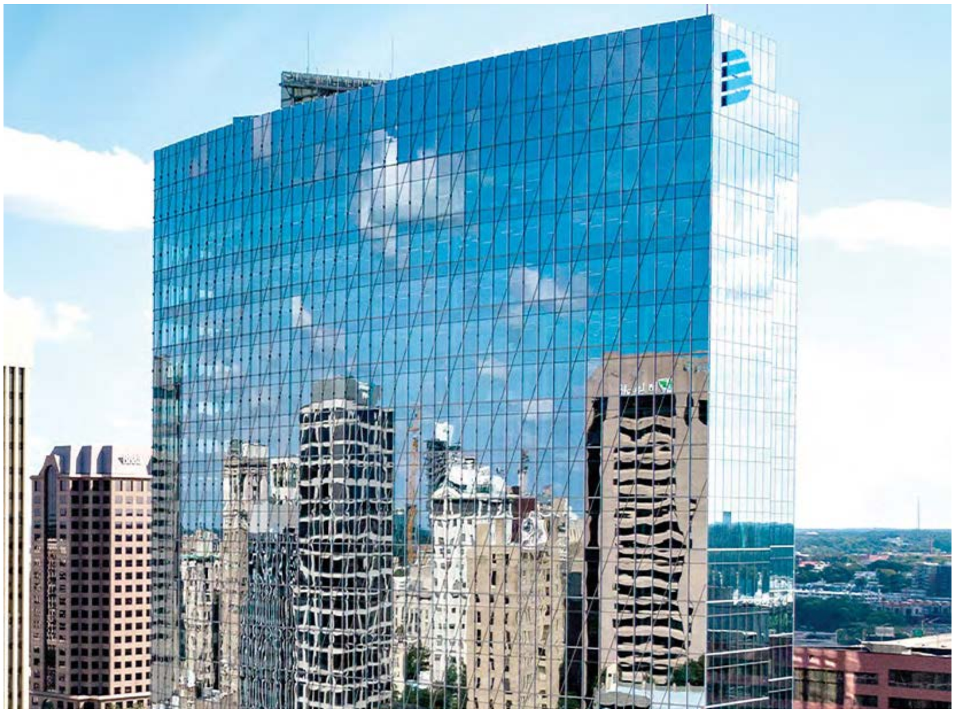
Why This Matters

The plan is the latest and apparently largest in a wave of proposals for data centers co-located with generation.

Stacks and towers at the former Homer City Generating Site before the facility was retired | *Shutterstock*

Citing Inflation and Load Growth, Dominion Asks Virginia for Higher Rates

By James Downing


Dominion Energy headquarters in Richmond, Va. | *Dominion Energy*

Dominion Energy Virginia has filed for its first base rate increase in decades, citing pressure from inflation and the need to reliably serve a growing customer base.

The request would raise the typical residential customer's bill by $8.51/month starting Jan. 1, 2026, and another $2/month starting Jan. 1, 2027, Dominion said in an application filed March 31 with the State Corporation Commission (*PUR-2025-00058*). The new rates would mark the first increase in base rates since 1992. Dominion said its residential rates have increased by 40% lower than the rate of inflation over the past decade.

"We're focused on providing exceptional value for our customers every single day," Ed Baine, Dominion president of utility operations, said in a statement. "Outside of major storms, we deliver uninterrupted power 99.9% of the time, and we're significantly reducing storm-related outages as well. This proposal allows us to continue investing in reliability and to serve our customers' growing needs."

The last biennial rate case came in 2023, and since then the company has faced higher costs of labor and materials including cables and wires, poles, transformers and power generation equipment.

In a separate application to the SCC (*PUR-2025-00059*), Dominion asked to move higher power capacity costs from its base rate to the annual fuel rate that would take effect July 1 and raise the monthly fuel rate paid by a typical residential customer by $10.92. The higher bills also include the fuel cost from extended cold weather this January and a $3.99 fuel credit from a previous rate case. Dominion passes through those costs and does not earn a profit on them.

Why This Matters

Dominion serves part of the biggest data center market in the world, and the rate case, as well as an ongoing IRP, will have to deal with its rapidly growing load.

Moving capacity expenses to fuel will increase the fuel factor by $1.98 for the typical residential customer, but it leads to a drop in base rates of $6.22 starting Jan. 1, 2026, according to the firm's public application with the SCC.

Separating out PJM capacity prices into base rates and energy market costs in its fuel rates predates Dominion's membership in the RTO and likely would not be done today given how much the company has to pay under the Reliability Pricing Model.

The delays in running auctions also prompted Dominion to make the request as it cannot accurately forecast what the price will be through the end of 2027, with two more auctions yet to run and one that will come after its rate case, it told the SCC.

On top of the new rates, Dominion also proposed creating a new rate class for high energy users that would cover data centers, and ensuring that those high-use customers pay their full cost of service and others are protected from stranded costs. Under the proposal, high energy users would have to make a 14-year commitment to pay for their requested power, even if they use less.

The Piedmont Environmental Council said that because the General Assembly failed to pass any meaningful reforms to how data centers are handled, the SCC's review of Dominion's rate case and its integrated resource plan are important to ensuring their growth is handled while keeping prices reasonable and environmental goals within reach. The group said it would work to ensure data centers pay their fair share.

"Virginia is in danger of falling behind and becoming the 'how not to' example that other states are using to avoid what has happened here. Ohio, Georgia, Texas, Indiana, Washington and Maryland are doing what Virginia's policymakers and regulators have failed to do thus far," PEC President Chris Miller said in a statement. "The SCC has the opportunity to take action now — and ensure data centers won't overwhelm the power grid, drain statewide water resources and further intrude on areas never meant to be industrialized." ■

NJ Lawmakers Sound Energy Supply Alarm

Pending Rate Hikes Trigger Concerns over Supply-demand Imbalance

By Hugh R. Morley

New Jersey lawmakers pushed back on the state's all-electricity, clean-energy strategy at a heated committee hearing March 28, urging an all-the-above approach as PJM faced criticism for failing to foresee a dramatic hike in demand that helped trigger a 20% rise in the average customer's bill.

Facing predictions that electricity demand could rise by more than 60% by 2050, driven in part by the expected arrival of data centers, greater electric vehicle use and the state's shift toward building electrification, lawmakers said the state needs to consider all options that could rapidly boost generation capacity. (See *NJ Releases Electrification-focused Energy Master Plan*.)

The turbulent, five-hour meeting convened by a Select Committee of Senators and the Assembly Telecommunications and Utilities Committee underscored the severity of the potential power shortfall facing New Jersey and its likely impact in further pushing up rates.

The two Democratic co-chairs of the meeting suggested that the state needs to look beyond Gov. Phil Murphy's (D) tight focus on renewable energy. During his seven years in office, Murphy has championed EVs, building electrification and a now largely stalled effort to create an offshore wind sector able to generate at least 11 GW.

"The storms are going to keep coming, and we need to look at renewable energies," said Sen. Paul Sarlo (D), one of the co-chairs. "But we can't just sit idle for the next five to seven years and not open our eyes to other concepts."

That was the "loud and clear" message of the committee members, he said. He asked Christine Guhl-Sadovy, president of the New Jersey Board of Public Utilities (BPU) and a Murphy appointee, if her agency would agree to "go forward with repurposing an existing plan for clean natural gas" while also pursuing renewable energy. Under prodding, she replied only that "we need to explore all options."

Assemblymember Wayne DeAngelo (D), the second co-chair, said the state needs a "well diversified energy generation portfolio" that includes wind, battery storage, nuclear and natural gas. Plans to go from gas heating to heat pumps will require a major, potentially burdensome residential infrastructure upgrade, he said.

| *Shutterstock*

"Seventy-five percent of our homes in New Jersey are heated with natural gas. Sixty-five percent of our businesses are heated with natural gas," he said. "And we haven't even talked about our data centers, which are popping up all over the place."

Republicans, who have long called for the state to adopt a broader portfolio, blamed Murphy's policies for the state's dilemma.

"I can't help but get the impression today that we're here because all of a sudden the rates went up, and people are like, 'Wow!' … like it wasn't foreseen or couldn't have been predicted," Sen. Anthony M. Bucco (R) said. "Experts have said the same thing: that we're just not going to be able to produce enough [electricity]. … We've all been saying that; you can't completely electrify the state in such a short period of time."

PJM Criticized for Perceived Flaws

But some of the most vigorous criticism was directed at PJM and its capacity market. In written testimony delivered at the hearing, Brian O. Lipman, director of New Jersey's Division of Rate Counsel, said that "clearly PJM is the easiest target in the room, and not without reason."

"PJM and its markets are a significant factor as to how we got to this problem," he said. "Everyone saw the pending retirements of generators. The issue did not come to a head because PJM was able to mask the problem with excessive available generation. The system is broken. The capacity auctions are not doing their job. The generation queue is not doing its job."

Legislators convened the hearing to address concerns about a 17 to 20% hike in the average electricity bill that will begin June 1 as a result of a basic generation service (BSG) auction in February.

Those BSG bid prices were shaped by PJM's capacity market auction in July, which set capacity prices at record levels, about 10 times as high as the previous auction. The auction sets the wholesale prices in the region that help shape bids in the BPU's auction. (See *PJM Capacity Prices Spike 10-fold in 2025/26*

Auction.)

BPU officials say they believe the bids were inflated by PJM demand forecasts that failed to properly include all the clean capacity expected to come online.

In a March 25 letter to PJM discussed at the hearing, Guhl-Sadovy said the BPU had "serious concerns" about PJM's plan to reduce the "recognized capacity value of generation resources" in its upcoming auction because it used the same "flawed reliability modeling" that produced the high prices. She said PJM's Independent Market Monitor calculated that the prices would have been half as high if not for those "flaws" that "severely undercounted available supply."

"The cost of PJM's mistakes to New Jersey consumers in the July 2024 capacity auction alone will be at least $800 million," Guhl-Sadovy wrote. "PJM should therefore be working to ensure that no critical flaws remain in its capacity market design."

Calculating Generator Capacity

PJM says the pending supply shortage is in part because of decarbonization efforts that have shut down older, fossil fuel-fired plants faster than new plants have come online. The RTO has long faced criticism about the slow pace of approvals for new generating sources, in particular renewables, although it says its new queue system will speed up the process.

Asim Haque, senior vice president for PJM, disputed the suggestion that the RTO should have anticipated the "major uptick in demand." For years demand across the system was flat, but that changed recently because of data centers, electrification and onshoring of the U.S. manufacturing industry.

"The market is essentially holding a mirror and reflecting the reality of the supply-demand challenge," he said. "And unfortunately, consumers are now seeing that on the bill side.

"If we're all being very truthful with one another, nobody saw this coming," he said. "We certainly saw the supply-demand imbalance sort of changing many years ago ... but the demand increase, in particular, this uptick, is something that is a newer phenomenon."

Addressing criticism of the RTO's rules, Haque said PJM is constantly receiving stakeholder input, but it can't change them without FERC approval.

One complication in trying to calculate supply is the variable output of some clean resources. A group of solar resources totaling 200,000 MW of capacity, for example, results in only about 20,000 MW of actual power because PJM calculates it operates at only about 10% of capacity, he said.

New Jersey's Picture

In New Jersey, which imports 35% of its electricity, the RTO is predicting demand will increase by 2.8 to 4.7% over the next 10 years, Haque said. The state planned to meet that increase in large part through wind generation: Of the state's 16,000 MW in PJM's queue, about 12,000 MW are OSW, he said. "As we sit here right now, those projects have not materialized."

Guhl-Sadovy said New Jersey has 79 projects in the PJM queue, mainly solar and storage that are "waiting for interconnection review to get connected to provide electricity." She said clean energy projects could be among the fastest to start generating energy once approved, adding that the federal government disrupted that process by halting wind projects.

"The fact of the matter is that thousands of megawatts of generation were going to come online in New Jersey to support New Jersey and the PJM grid between 2029 and 2032," she said.

Under questioning, Guhl-Sadovy acknowledged that her agency suspects that one reason for the RTO's slow approval process of clean energy projects is that "PJM has made decisions that lean towards fossil fuel generation and the states that have large-scale fossil fuel generation."

Data Center Reality?

Sen. Bob Smith (D) questioned the veracity of the claim that power-hungry data centers are driving the power imbalance. He said the U.S. Energy Information Administration has reported that the state's electric load dropped from 75.4 TW to 71.1 TW in 2023.

"You mentioned the projected increase: Our history has not been out-of-the-box demand in New Jersey, but actually, at least recently, declining demand," he said to Guhl-Sadovy. "Do you actually have data center AI in the queue at BPU? ... How do we know any of this is true?"

He said PJM does not know if the proposed AI data centers are "real or phony-baloney" and called for the RTO's policies to be investigated, saying the specter of data center demand is a "preemptive rate increase with no basis in fact."

Guhl-Sadovy said the question is a "great point," adding that the utilities have said they have interconnection requests from data centers and her agency is waiting for details.

Haque acknowledged that on the demand side, the industry is "legitimately struggling with sort of what is real on these data center forecasts." One solution already adopted by some states is to put "gating criteria" on data centers that submit connection applications, requiring them to "put money down up front," he said. ■

PJM OC Briefs

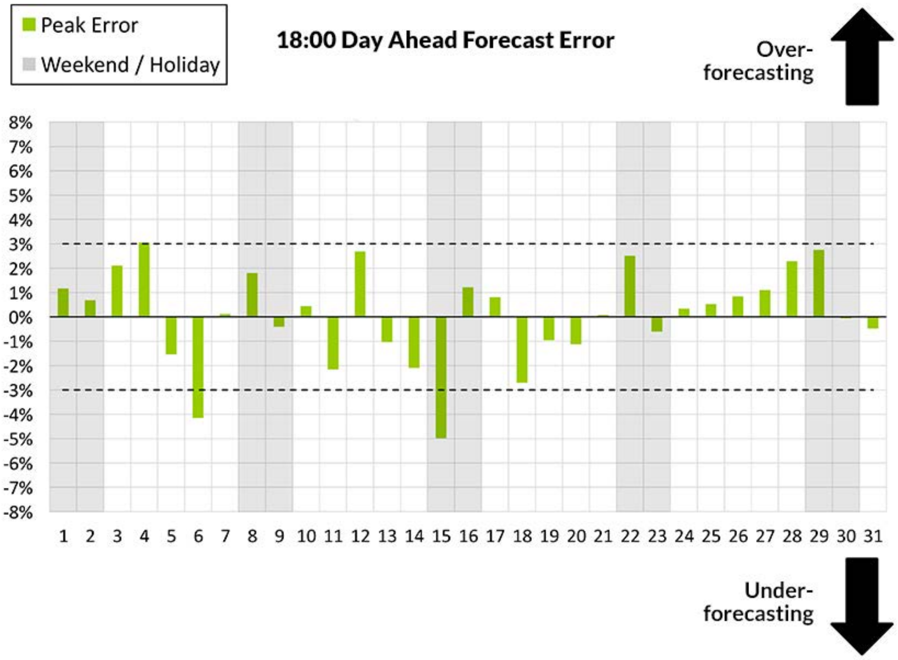
Stakeholders Endorse Manual Revisions

VALLEY FORGE, Pa. — The Operating Committee endorsed a pair of revisions to Manual 1: Control Center & Data Exchange Requirements and Manual 37: Reliability Coordination.

The *changes* to Manual 1 would align with NERC standards IRO-010, TOP-003 and EOP-008 and include updating the Generation Scheduling Service table with generation periodic eDART and Cold Weather Checklist data requests.

The periodic review of Manual 37 led to *recommendations* to update references throughout the document and remove the 3 p.m. posting deadline for next day reliability analyses.

March Operating Metrics



A PJM graphic shows the peak forecast error for March 2025. | *PJM*

PJM's Marcus Smith *presented* the forecast error and operating metrics for March, which saw a 1.47% hourly forecast error and three days exceeding the 3% peak error benchmark.

Warmer-than-expected temperatures March 4 led to load coming in lower than expected, pushing the peak error to 3.05%, while the hourly rate was 1.63%. March 6 saw cooler temperatures corresponding to peak loads being 4.14% lower than forecast. A similar dynamic was seen March 15, when the peak was 5.01% lower than forecast.

Three shared reserve events, one high system voltage action, seven post-contingency local load relief warnings and six shortage cases were issued. Two of the shortage cases were on March 15 due to lines tripping. Four were on March 19 and were attributed to load increases and reduced reserves being available.

Update on Regulation Market Design

PJM's Damon Fereshetian *presented* an update on the implementation of PJM's regulation market redesign, the first phase of which is set to go live Oct. 1, 2025. The second phase is scheduled to roll out a year later. (See "PJM Presents Regulation Market Rework," *PJM MRC/MC Briefs: Dec. 20, 2023*.)

Phase 1 includes consolidating the RegA and RegD signals into one bidirectional signal, shifting to 30-minute clearing from hourly, eliminating the accuracy and delay components of performance scoping to focus only on precision, and changes to opportunity costs and the regulation requirement. The RegD product provides fast response, while RegA is used for long deployments.

Training on the changes is set to begin in May. Sandbox testing software will launch either that month or in June. PJM targets endorsement of manual language codifying the changes in August, with education sessions Aug. 12 and Sept. 5. ■

— Devin Leith-Yessian

PJM MIC Briefs

Stakeholders Narrowly Endorse Uplift Changes

VALLEY FORGE, Pa. — The Market Implementation Committee endorsed a joint PJM and Independent Market Monitor *proposal* to rework how uplift and deviation charges are calculated for market sellers depending on how they respond to market signals and dispatch instructions. It passed with 53.3% support and is set to go for a first read at the Markets and Reliability Committee on May 21. (See "First Read on Proposal to Overhaul Uplift," *PJM MIC Briefs: March 5, 2025*.)

The changes would establish a new tracking ramp-limited MW desired (TRLD) metric to replace the three existing MW desired metrics used in calculating balancing operating reserve (BOR) credits and deviation charges. The TRLD would follow how a unit responds to instructions over time, rather than focusing on individual five-minute intervals as the ramp-limited desired, dispatch and locational marginal pricing-desired metrics do.

PJM's Lisa Morelli said that would address scenarios where a unit ignoring dispatch and keeping its output steady can avoid deviation charges.

The TRLD would account for any dispatch instructions arising from ancillary services a market seller is responding to as well, such as regulation or sync reserve, allowing corresponding automatic exemptions from deviation to be eliminated.

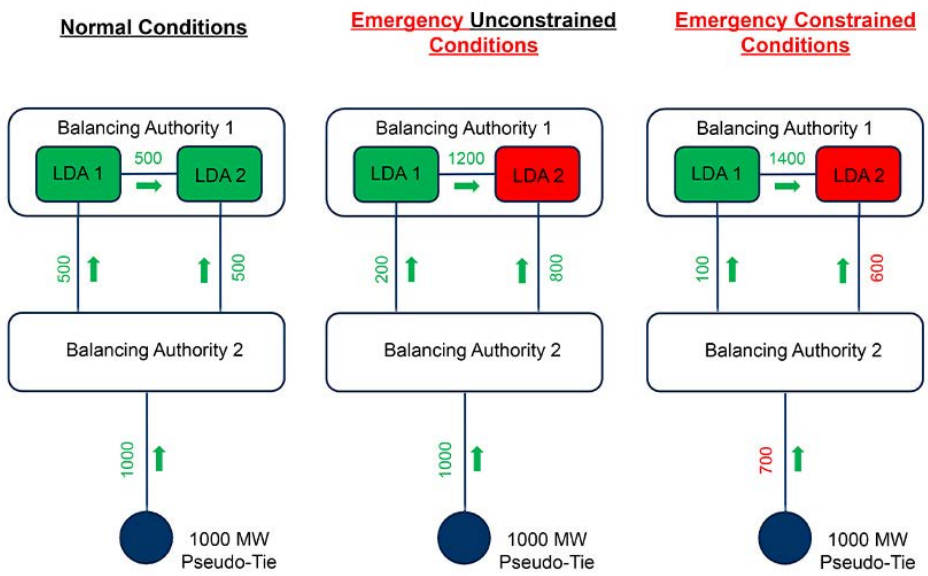
In past meetings, Morelli gave the example of a unit operating at 100 MW being dispatched down to 95 MW in accordance with its ramp rate. If that unit ignored the signal and stayed at 100 MW, it would not exceed the 10% margin that defines when a unit is deviating from dispatch under the status quo. Additionally, because dispatch is limited by ramp rates in the next interval, PJM could bring it down only to 95 MW in the following interval.

The proposal also would rework the BOR credit formula by taking the lesser of real-time output or the TRLD and adjusting for ramp parameters for each interval, which Morelli said would simplify the equation. The start and end points for uplift eligibility would be revised to align with when a market seller's commitment began and to run through either the end of that commitment or the unit's minimum run time.

Morelli said PJM's goal is not to reduce uplift and the changes are likely to be a net benefit for many participants, as they also address scenarios where generators are undercompensated in some scenarios.

If endorsed by the Members Committee in July, Morelli said PJM would aim to file tariff revisions at FERC in September. The changes would be implemented in two phases, starting with simulated results in market settlements reporting system (MSRS) reports before affecting actual settlements in late 2026 or early 2027.

Responding to stakeholders questioning how PJM could respond to any gaps or unintended consequences identified during the soft launch, Morelli said the intention is to have enough detail in the tariff language to give direction to how the TRLD would function, with finer detail spelled out in the manuals. Any edge cases stakeholders are concerned about could be addressed by adjusting the manuals without needing to make additional FERC filings. The governing document language likely would empower PJM to adjust the TRLD if there are instances where SCED would dispatch a unit inconsistent with locational marginal pricing or the unit's offers.



A PJM graphic shows how pseudo-tied resources could be required to be curtailed when an LDA they are connected to requires additional capacity. | *PJM*

Committee Endorses Manual 11 Periodic Review

Stakeholders endorsed *revisions* to Manual 11: Energy & Ancillary Services Market Operations drafted through the document's periodic review. The changes were deferred during the committee's March 5 meeting after concerns were raised with the language designating data centers as plug load. (See "Periodic Review of Manual 11 Deferred," *PJM MIC Briefs: March 5, 2025*.)

PJM's Joseph Tutino said the proposal was changed since the first read to include data centers and crypto mining as "business segment" load following feedback that plus load typically includes smaller devices, such as household appliances. He said the remaining changes are mainly typographical.

PJM's Maria Belenky told the committee in March that data centers are considered plug load for the purpose of curtailment service providers (CSPs) reporting load enrolled in demand response.

First Reads on Manual Revisions

PJM presented a first read on revisions to *Manuals* 6, 11, 28 and 29 to conform with FERC's May 2023 order accepting a PJM proposal on how it proceeds with settlement under a market suspension. PJM's transmittal letter states that a market suspension never has occurred but could result from "extraordinary circumstances such as a failure of computer systems." (See "Market Suspension," *PJM Market Implementation Committee Briefs: June 8, 2022*.)

The filing stated that the tariff has no way of determining energy and ancillary service prices when zonal dispatch rates cannot be calculated by software. Three different sets of rules are included for determining real-time prices when suspensions last less than six hours, between six and 24, or for longer. Shorter suspensions would use the average real-time prices for each hour prior to and following the outage; for moderate duration events, day-ahead prices would be used if available, otherwise real-time prices would be used; and for suspensions exceeding a day, an aggregate supply curve would be developed (*ER23-1431*).

The proposed Manual 28 language would use actual output for calculating energy offers during real-time energy market suspensions. Lost opportunity costs (LOC) would not be included for suspensions longer than one day, and BOR charges would be allocated to real-time load plus exports if a suspension exceeds one hour.

PJM also gave a first read on *revisions* to Manual 18 to conform with FERC orders granting several changes PJM sought to make to its capacity market in recent months (*ER25-682*, *ER25-785*, *ER24-2995*).

The bulk of the changes arise from FERC's Feb. 14 order granting a host of capacity market changes meant to address tightening supply and demand. The corresponding manual revisions would codify delayed Base Residual Auction (BRA) dates; model resources operating on reliability-must-run (RMR) agreements as capacity; continue the use of a combustion turbine generator as the reference resource; and clarify that market sellers do not hold "safe harbor" from claims of market power exercise by holding a categorical exemption from the requirement that all resources holding capacity interconnection rights (CIRs) must offer into the capacity market. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

It also includes the elimination of must-offer exemptions for intermittent, storage and hybrid resources, requiring market sellers to offer those units into capacity auctions starting with the 2026/27 BRA scheduled to be conducted in July. Stakeholders and intervenors argued the exemption artificially increased auction clearing prices, while many generation owners argued the existing and proposed market rules do not allow them to reflect the risk exempt resources would take on with a capacity obligation.

The final change would be to memorialize the removal of the energy efficiency addback and eliminate the resource class outright following the 2025/26 delivery year. PJM argued to the commission that the addback was a holdover from a prior set of rules and no longer was needed, as EE was captured in its load forecast. Removing capacity status for EE was sought as the RTO argued that it could not be demonstrated that capacity market revenues were used to reduce load. (See *PJM Asks FERC to Eliminate Energy Efficiency from Capacity Market*.)

Stakeholders Discuss Pseudo-tied Resources

The committee continued its discussions on how pseudo-tied generators are assigned to locational deliverability areas for the purpose of determining clearing prices and the amount of local capacity PJM models as available within a zone. The subject was brought up by the North Carolina Electric Membership Corp. (NCEMC) to explore whether a load-serving entity seeking to self-supply with pseudo-tied generation should receive the clearing price for an LDA or the RTO-wide clearing price, with the latter being the status quo.

PJM's Nebiat Tesfa *said* pseudo-tied resources are those that have an indirect connection to PJM, hold firm transmission service and are studied to ensure deliverability akin to internal resources. Those studies do not, however, determine whether any particular resource is deliverable to a specific LDA; to ensure the right to inject to an LDA, either incremental capacity transfer rights (ICTRs) or investment in qualifying transmission upgrades (QTUs) must be obtained. In some cases, modeling the flow from a pseudo-tied resource can use the reliability requirement for an LDA to increase, she said.

PJM's Tim Horger said the RTO's priority going into the topic is ensuring there are no inconsistencies between internal and pseudo-tied resources when modeling congestion or transmission.

In its own *presentation*, NCEMC said there were circumstances in the 2025/26 BRA where LSEs were exposed to price separation within their LDAs and were prevented from using their own resources adjacent to that zone and which they believe are electrically serving that load. It said analysis of dispatch data shows that those units are providing congestion management in Mid-Atlantic Dominion

Horger said PJM and stakeholders have to be careful when considering changes down the path of using distribution factor (DFAX) analysis to determine whether a given resource is helping a specific LDA.

Carl Johnson, representing the PJM Public Power Coalition, said if resources are tied to an LDA, especially when it's the same organization trying to serve load with its own resources, there should be a way of recognizing that the cost shouldn't be different just because an LDA separates.

PJM's Jonathan Kern said the CETL study is agnostic about which capacity resource is supplying an LDA, so there's going to be some association with the CETL and generation outside the LDA but not associated with any particular resource. ■

— Devin Leith-Yessian

PJM TEAC Briefs

PJM Presents Scope Change to RTEP Projects

PJM *presented* a $97 million increase to a project included in the 2022 Regional Transmission Expansion Plan (RTEP) Window 3. The change would remove two 230-kV lines between the Mars substation and Sojourner and Shellhorn facilities and reroute them to terminate at the south side of Mars to avoid intersecting with new lines being planned. The original scope is to build a 500-kV line between Mars and Golden and a 230-kV line from Mars to Lockridge and terminating at Golden. The changes bring the total cost to $439.9 million.

Projects included in the 2022 RTEP Window 3 also have obviated the need for two prior projects totaling $7.5 million. The rebuilding of a line between Loudoun and Morrisville will supplant a $4.5 million project to rebuild a 1.3-mile segment of that facility. A $3 million project to replace breakers at the Ox 500-kV substation also is being canceled as the same work is included in baseline projects.

Supplemental Projects

FirstEnergy *presented* a pair of projects amounting to $37.6 million to replace two 500/138-kV transformers and disconnect switches at its Pruntytown Substation in the APS zone due to the assets nearing end of life and experiencing maintenance issues. The projects are in the conceptual phase with in-service dates of Dec. 13, 2030, and June 13, 2031.

The replacement of another aging 500/345-kV transformer at Wylie Ridge is expected to cost $20 million with a projected in-service date of Dec. 13, 2030. The transformer has increased hydrogen and ethylene readings, moisture buildup and low dielectric strength, according to FirstEnergy.

American Electric Power *presented* a $50.4 million project to build a new 345-kV substation, to be named Navistar, in the AEP zone to serve a new customer bringing 437 MW of load to the New Carlisle, Ind., area. The facility would be cut into the Dumont-New Prairie 345-kV double circuit lines and would be configured as a breaker and a half with 11 345-kV breakers and two bus ties to the customer.

The project is in the scoping phase with a projected in-service date of March 15, 2027.

Dayton Power and Light *presented* a $480 million project to serve two 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 be expanded to breaker-and-a-half configurations to accommodate a 25-mile double circuit between the two sites, as 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 Jeffersonville load is 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.

PPL *presented* a $101 million project to expand the proposed Tresckow 230-kV substation to include a four-bay breaker and a half 69-kV yard to serve a customer expected to bring 300 MW of load to Hauto, Pa., in 2028. Four 230/69-kV transformers also would be installed, as well as two 69-kV double circuit lines connecting Tresckow to the Frac-Tres 69-kV No. 1 and No. 2 lines. The project is in the conceptual phase with a projected in-service date of May 30, 2028.

Duke *presented* a $49 million project to build a new 345-kV substation, to be named Gold Finch, along the Silver Grove-Red Bank 345-kV line to serve a new customer seeking to interconnect 300 MW in Clermont County, Ohio. Gold Finch would be configured as a ring bus with four 345-kV breakers and a control building. The project is in the scoping phase with an in-service date of June 1, 2028.

Dominion *presented* a $450 million project to upgrade several lines and transformers to address load drop and thermal violations on the Ladysmith CT-Fredericksburg and Ladysmith CT-Four Rivers 230-kV lines. The violations were identified in the 2025 do no harm analysis. The project is in the conceptual phase with an in-service date of July 1, 2029.

Phase 1 of the project, expected to be complete in January 2028, includes rebuilding 6.5 miles of the Summit DP-Fredericksburg Sub 230-kV line with higher capacity conductor; reconductoring 7.3 miles of the Ladysmith-Ladysmith CT line; adding two 500-kV capacitor banks to Ladysmith; and building a new 230-kV line running between Ladysmith, New Post, Lee's Hill and Allman using a mix of new structure and vacant arms.

Phase 2 would go online in July 2029 to expand the Kraken 500-kV switching station to cut into the Summit DP-Fredericksburg Sub 230-kV line, the St. Johns-Four Rivers 230-kV line and the planned Ladysmith-Allman 230-kV line. The St. Johns-Four Rivers and Four Rivers-Elmont lines also would be rebuilt. The 115-kV lines from Fredericksburg-Four Rivers, Pinewood-Four Rivers, Four Rivers-Elmont, and Pinewood-N. Doswell lines would be "wrecked" and a new double circuit 230-kV line would be built from Kraken to Allman, along with a single circuit line from Kraken to Elmont.

Several additional Dominion projects would serve new service requests across its footprint. A $10.1 million project would construct a 230-kV ring bus with four breakers at its Trabue substation; two new 230-kV substations, Ruther Glen and Carmel Church, would be added to the Ladysmith CT-Four Rivers line for $87 million; and two new 230-kV substations, New Post and Lee's Hill, would be built along the Fredericksburg-Ladysmith CT line for $43 million.

The Wabash Valley Power Alliance *presented* an $80 million project to construct a 15-mile, 345-kV line between AEP's Elderberry substation and NIPSCO's Stillwell substation. The line will be operated by MISO and is being submitted to PJM's supplemental planning process to allow study coordination. ■

— Devin Leith-Yessian

Brattle Report Stresses Need for Southeast Regional Tx Plan

Region's Current Planning Approach 'Insufficient,' Paper Contends

By Amanda Durish Cook

A new Brattle Group report spotlights the Southeast as the only major U.S. region without thorough transmission planning and recommends it develop a portfolio of projects or risk failing to keep up with the times.

The April 2 *report* — prepared for the Carolinas Clean Energy Business Association, Clean Energy Buyers Association and the Southern Renewable Energy Association (SREA) — concludes that "the status quo approach for planning and building the future region-wide Southeast grid is insufficient" to meet load growth and growing reliability risks brought on in part by weather extremes.

"Transmission development today is driven by utilities planning their systems in isolation, focusing primarily on their service areas (or in some cases the joint network within a state) instead of taking a broader, regional approach to grid expansion," authors J. Michael Hagerty, Peter Heller and Evan Bennett write. They asked Southeastern utilities to "think larger and embrace regional solutions that supplement utility-specific upgrades."

The Brattle report says a bolder planning approach is a must, especially since meaningful regional transmission projects have failed to materialize for more than a decade through the utility-created Southeastern Regional Transmission Planning Process (SERTP). It concludes that recent Southeast transmission projects conceived separately by utilities or even small groups of utilities such as the Carolinas Transmission Planning Collaborative and the Georgia Integrated Transmission System are lacking.

"Without a regional, forward-looking strategy that maximizes the value of transmission investments, Southeast utilities risk inefficiently investing in lower-value local reliability projects within their respective systems, resulting in rising transmission rates without achieving the greatest return on their transmission investments," the authors said. "Instead of maintaining existing systems, utilities should prioritize regional upgrades that supplement necessary local reliability upgrades and support a reliable grid, new energy generation and long-term load growth."

| Southern Co.

Why This Matters

The report says a bolder planning approach is needed, especially since meaningful regional transmission projects have failed to materialize for more than a decade.

In an April 2 webinar to review the report, Hagerty pointed out that the Southeast's big players — Southern Co., Duke Energy, Louisville Gas & Electric and Kentucky Utilities Co. — have quadrupled spending on local transmission needs since the early 2000s, when they collectively spent about $500 million per year. Now, those utilities have spent nearly $2 billion annually in the past five years. He and the two other report authors said the spending was mostly to replace aging infrastructure, connect new generation and support "moderate" load growth.

The report warned that conducting transmission planning largely in isolation leads to missing out on opportunities to build larger, more cost-effective projects and their resilience benefits.

The report said a $5 billion investment in three 500-kV lines that SERTP evaluated in 2024 could save $2.9 billion conservatively on production costs, $3.3 billion on load diversity and $1.6 billion on resilience benefits. However, the report said SERTP adopted an "overly narrow view of cost savings" and found no benefits of increased transfer capability among Duke Energy, Southern Co. and the Tennessee Valley Authority due to the three major upgrades.

However, the report said the Carolinas Transmission Planning Collaborative's in-progress *Multi-Value Strategic Transmission Study* could show promise for the two states and be replicated on a larger scale in the region.

'Lifelines' for SERTP

SREA Executive Director Simon Mahan said the Southeast's unprecedented projected load growth means new transmission "lifelines" are necessary. Without them, the Southeast grid risks higher energy costs and reliability disruptions.

"At the end of the day, lives are on the line without enhanced transmission solutions," Mahan said.

Lead author Hagerty said by 2035, the Southeast's electricity demand is expected to rise by 25% to 21 GW. He and the other authors noted that amount is similar to a doubling of New York City's demand, and said the Southeast will need regionally planned transmission to connect the estimated 80 GW in new generation to keep up while maintaining reliability.

Hagerty said SERTP planning is inadequate to take on the modern needs of the Southeastern grid. The report criticized SERTP's planning structure — composed of 10 sponsor utilities from 12 states with no independent staff — as too narrow to be effective. Mahan said the process, which isn't open to the public and state regulators aren't involved in, is mysterious.

Hagerty also said SERTP's single model doesn't produce a realistic future resource mix and the group should reach out to states to get a better view of future generation.

"The proof is in the pudding," Hagerty said, adding that over the last 11 years, SERTP hasn't proposed a single regional upgrade. He said the process is "unlikely to support the investment needed in the Southeast" as demand rises and that a lack of regional planning would correlate with higher costs, delays in serving new load and reliability troubles as more extreme weather stresses the grid.

Carolinas Clean Energy Business Association Executive Director Chris Carmody said Southeastern utilities are building "very tall silos" of new generation that could burden ratepayers with higher costs.

"Without transmission, it's going to be dressed up with nowhere to go," Carmody joked. He said the Southeast should adopt Eisenhower's attitude when trying to get the interstate highway system built.

Carmody added that "one weather event after another" seems to strike the Southeast, and regional transmission could stand in for hard-hit areas that lose service on lines.

The report said FERC's Order 1920 could provide the Southeast with an opportunity to create proactive planning that exceeds the federal rule's parameters. SERTP could use the multi-value and scenario-based planning that exists in other planning areas in the country and incorporate load forecasting to land on portfolios of transmission solutions or even interregional projects, it said.

Hagerty said the Southeast should view Order 1920 as a "floor" and go beyond the rule's requirements for an even more dependable grid.

The Brattle report asked SERTP to shed more light on its planning and share input assumptions, study results and project costs publicly. It also recommended SERTP adopt a "beneficiary pays" method for cost allocation of regional lines.

Carmody said Southeast utilities should ignore the instinct to build up their islands and work together to avoid leaving their systems vulnerable or missing out on a new manufacturing plant. He said utilities can either choose to continue driving a 1950s Rambler or "accept that that's not going to be safe or efficient for us" and make investments.

"Proactive transmission planning supports a growing economy," Clean Energy Buyers Association's Katie Southworth added.

SREA previously criticized SERTP's planning and *said* Order 1920 could nudge SERTP "away from a process that studies regional transmission lines to justify not building them."

SERTP did not respond to *RTO Insider*'s request for comment on whether there is room for improvement in its regional planning or its still-developing plans to comply with Order 1920.

Recent calls for stronger transmission planning in the Southeast also extend to MISO South.

Stakeholders at MISO's Board of Directors Week in March lined up during a public comment period to ask the RTO to engage in long-term planning in the RTO's South region. While MISO has designated two long-term portfolios at a combined $32 million in the Midwest, grid planners have yet to prescribe any long-term projects for the South region. (See *MISO Fields Divergent Calls for Stronger South Planning, IRA Reversal in Tx Futures*.) ■

MISO, SPP Solicit Feedback on Joint Transmission Studies

By Tom Kleckner

MISO and SPP staff asked for input on a joint system study in 2025 during their annual transmission issues evaluation March 28 with their Interregional Planning Stakeholder Advisory Committee (IPSAC), which was only too happy to discuss stakeholders' issues with the current process and suggest improvements.

Missouri regulators called for examining the region encompassing southwest Missouri, southeast Kansas, northeast Oklahoma and northwest Arkansas, rather than just Oklahoma and Arkansas. Clean energy groups urged the RTOs to increase the bidirectional interregional transfer capacity along the seam they say will generate billions of dollars in regional benefits. A transmission developer recommended that the staffs follow its road map in working with FERC to enable the "timely development" of interregional projects.

The staffs will use the feedback in determining whether or not they conduct a Coordinated System Plan (CSP) this year. They told the IPSAC in December that they will not perform a CSP in 2025 but will accept transmission issues for their annual review, as per their joint operating agreement (JOA). (See *MISO, SPP to Revise Joint Agreement, Focus on TMEP Process in 2025*.)

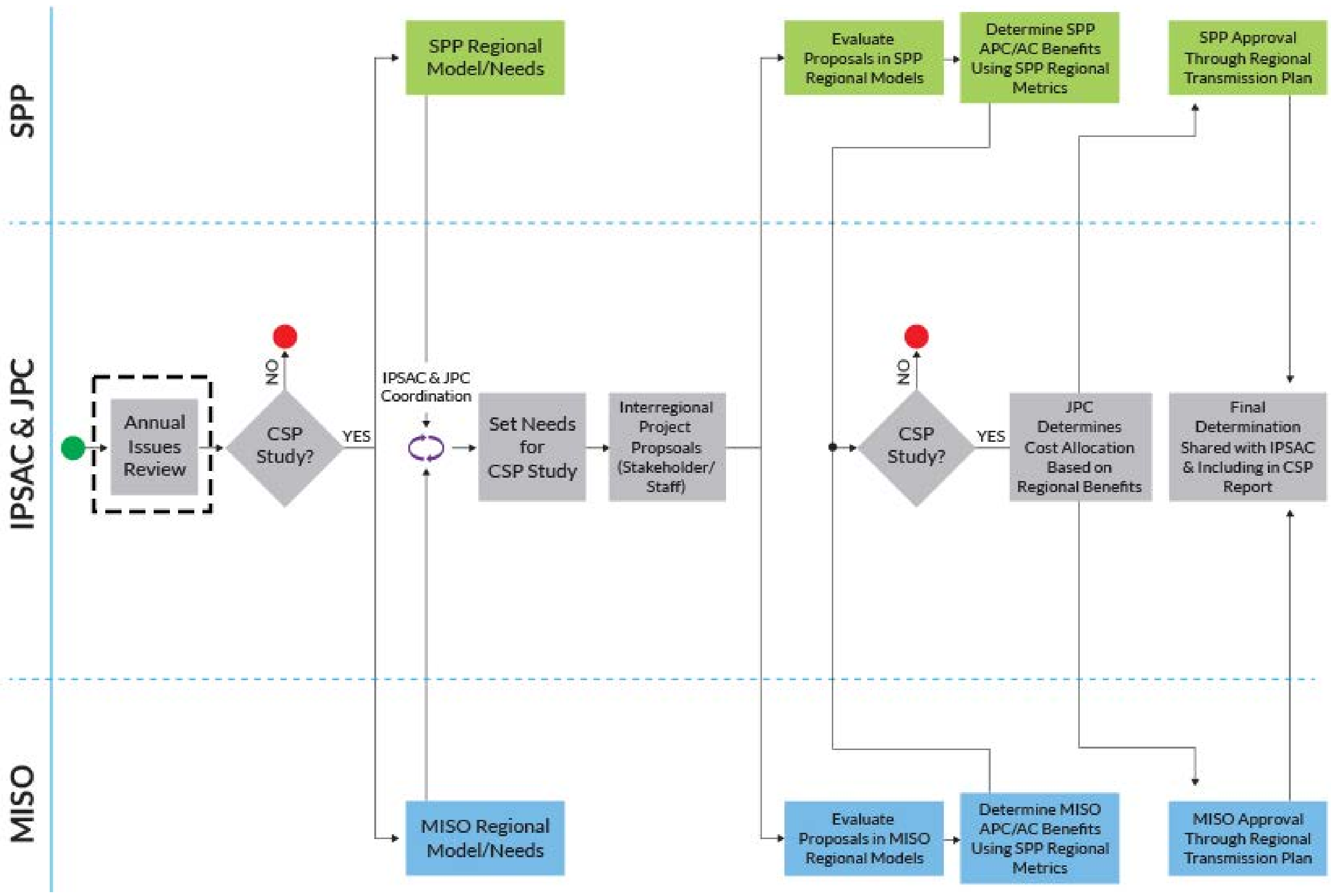
MISO's Jon George reminded stakeholders that the RTOs have proposed expanding the CSP's scope to yield a more robust and comprehensive interregional planning process in the 2024/25 planning cycle. They are focusing on identifying "immediately actionable" system upgrades that improve reliability and resilience and strengthening transfer capability between the two systems.

Why This Matters

MISO and SPP staff are asking for stakeholder input as they consider a joint system study in 2025. The staffs will use the feedback before they make a decision this year on a 2025 study.

The study incorporates reliability, economic and transfer analyses using forward-looking 10-year models and assumptions. It aligns with key elements of FERC Order 1920, staff said.

SPP and MISO have filed a waiver request with FERC for certain multiyear model-



The enhanced MISO-SPP Coordinated System Plan study process | *MISO, SPP* ing and benefit valuation requirements in their JOA. Staff said they believe the study can proceed as scoped, but that certain JOA provisions may prove challenging.

Stakeholders reacted positively to the RTOs' 2034 blended models for issue identification and benefits evaluation: economic, light-load reliability, and extreme hot and cold events. The blended models were also used in the 2023 CSP.

The Sustainable FERC Project and Natural Resources Defense Council's Natalie McIntire said the RTOs should be focused on building a bigger grid, given the increase in extreme weather.

"We really urge the RTOs to focus on the full seam for future comprehensive interregional studies," she said. "Things are changing so rapidly that we need to keep our focus on all parts of the seam and how we can optimize that for all consumers. The focus in this interregional transfer capability and resilience study on resilience during the extreme weather is great. We support that, but we think there's further work that can be done to really move away from the prior silo transmission planning frameworks that have been undertaken across the seam in the past."

The CSP builds on each RTO's respective regional process. The RTOs then coordinate on model development, issues identification and technical analysis throughout the evaluation process.

"We're already in a solution-submission window for the 2025 [SPP Integrated Transmission Planning portfolio], but to the best we can, we will definitely cross reference solutions from these studies," SPP's Spencer Magby said. "If we see something promising in these regions in the 2025 ITP, we'll be sure to screen them through this study as well."

The JOA, which was updated in 2019, requires that a CSP be performed every two years. Stakeholders have until April 23 to submit their final issues. At that point, the RTOs' Joint Planning Committee, which comprises staff from both grid operators, will meet and determine whether a study will be conducted.

Five previous CSP studies have failed to produce any joint projects over differences in allocating costs. That led the RTOs to try a different approach with the Joint Targeted Interconnection Queue, which identified a five-project portfolio estimated to cost as much as $1.6 billion that could support up to 29 GW of interconnecting generation along their seam. ■

Northeast news from our other channels

NYPA to Buy Former Power Plant Site for $206M — NetZero Insider

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

Company Briefs

Delta Acquires CenterPoint Distribution Companies in La., Miss.

Delta Utilities last week announced it has acquired CenterPoint Energy's three regulated natural gas local distribution companies that serve Louisiana and Mississippi.

The sale includes around 12,000 miles of main pipeline serving about 380,000 customers.

No financials were disclosed.

More: *KSLA*

Brookfield Nears $9B Deal for Colonial Pipeline

Brookfield Asset Management is said to be putting the final touches on a deal to acquire Colonial Pipeline, the largest U.S. fuel transportation system, for more than $9 billion including debt, according to people familiar with the matter.

Colonial's pipeline system stretches more than 5,500 miles from Houston to New York's harbor. It moves more than 100 million gallons of fuel daily, including gasoline, jet fuel, diesel and heating oil, according to its website.

A deal could be formally announced in the coming weeks, barring any last-minute snags, the sources added.

More: *Reuters*

APA Solar Invests $19.5M in Ohio Expansion

APA Solar, a solar racking company, last week announced it is planning to build a new 30,000-square-foot headquarters building in Ridgeville Corners, Ohio.

The company said it will invest $19.5 million and hire 133 people as part of the expansion. The investment follows an upgrade in 2023 in which the company invested $10 million to expand its Henry County manufacturing facility.

Construction of the headquarters is expected to be completed in early 2026.

More: *pv magazine*

Lithium Americas Reaches Final Decision for Thacker Pass

Lithium Americas last week said it has reached a final investment decision for constructing the first phase of the Thacker Pass lithium mine in Nevada.

The Thacker Pass project is a joint venture between Lithium Americas and U.S. automaker General Motors. Phase 1 of the project is expected to be completed in late 2027. Once open, it is expected to produce 40,000 metric tons of battery-quality lithium carbonate per year in its first phase, enough for up to 800,000 EVs.

More: *Reuters*

Federal Briefs

Venture Global's Calcasieu Pass LNG Facility Gets FERC Approval

FERC last week approved U.S. LNG developer Venture Global to commence service on the remainder of the facilities at the Calcasieu Pass LNG Terminal in Louisiana, according to a filing.

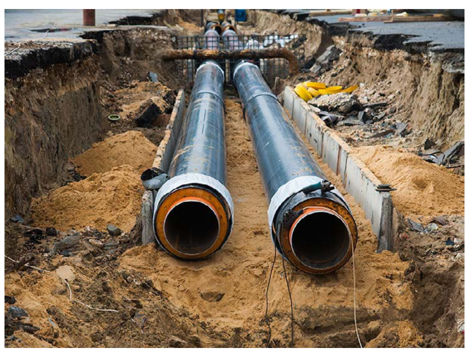
Venture Global recently asked FERC for permission to begin operations at its entire Calcasieu Pass LNG export facility and TransCameron pipeline project, the final step before moving to commercial operations.

More: *Reuters*

FERC Approves Pipeline Extension

FERC last week approved a 122-mile natural gas pipeline expansion cutting through East Tennessee.

The Ridgeline pipeline will stretch from Smith County to the TVA's Kingston power plant. To fuel the plant, Enbridge's pipeline company plans to extend its pipeline all the way to Roane County.



Construction is set to begin in the fall and be completed by fall 2026.

More: *WATE*

BLM Extends Public Comment Period for Oregon Lithium Project

The Bureau of Land Management last week extended the public comment period for a lithium exploration project in Oregon to April 25.

BLM has been reviewing Jindalee Resources' proposal to explore federal land for lithium since 2022. The agency published its resulting environmental assessment in late March and gave the public just five days to review and comment. BLM received more than 1,500 comments in those five days.

The proposal includes drilling at more than 260 sites across 7,200 acres of sagebrush desert in Malheur County, near the Oregon-Nevada border, in search of lithium.

More: *OPB*

State Briefs

REGIONAL

SouthCoast Wind Contract Delayed for a Third Time

SouthCoast Wind and utility companies in Rhode Island and Massachusetts last week announced a three-month extension to finish contract negotiations for the 147-turbine wind farm planned south of Martha's Vineyard and Nantucket.

The new June 30 deadline marks the third delay since Rhode Island and Massachusetts jointly unveiled plans in September to buy power from SouthCoast Wind following a solicitation that included Connecticut. Supply chain delays and inflationary pressures have driven up developer costs, prompting some companies, including SouthCoast, to renege on existing pricing agreements in hopes of a more lucrative deal. That has put more pressure on utilities and ratepayers to cover the rising expenses.

More: *Rhode Island Current*

COLORADO

Polis Signs Bill Recognizing Nuclear as Clean Energy

Gov. **Jared Polis** last week signed a bill that will have the state recognize nuclear energy as "clean energy."

This year's bill passed the Legislature with bipartisan support, with a 43-18 vote in the House and a 29-5 vote in the Senate.

Nuclear energy production in Colorado has been dormant since 1989, when the state's only nuclear power plant, Fort St. Vrain in Weld County, ceased operations.

More: *The Aspen Times*

IOWA

MidAmerican Energy Seeks New Natural Gas Fee

MidAmerican Energy last week filed a request with the Utilities Commission seeking approval to add a 0.4% capital investment charge to the bill of residential gas customers.

MidAmerican spokesman Geoff Greenwood said the charge, which would add about 17 cents to the average residential bill, would "cover costs that MidAmerican has already paid out that are associated with certain natural gas system costs."

More: *Radio Iowa*

MARYLAND

Gov. Moore Issues Executive Order that Could Delay EV Sales Penalties

Gov. **Wes Moore** last week issued an executive order that could delay initial penalties for EV manufacturers who do not meet sales goals under a prescriptive state plan that is supposed to take effect next year.

The order will maximize the Department of Environment's enforcement discretion "to ease compliance" with the rule — including by declining to enforce penalties for model years 2027 and 2028. Moore's order stated that President Donald Trump's tariffs and actions on electric vehicles, including rescinding funding for charging infrastructure, also pushed Maryland to intervene to assist manufacturers.

Maryland adopted Advanced Clean Cars II, which requires EVs to account for 43% of cars sold in the state by a manufacturer in the 2027 model year. The number grows to 51% in 2028, eventually reaching 100% by the 2035 model year. The state also adopted a similar rule for larger vehicles such as trucks. Moore's order also opens the door for the DOE to avoid enforcing penalties on those vehicles for model years 2027 and 2028, unless the agency releases an assessment on the rule by Dec. 1.

More: *Maryland Matters*

MASSACHUSETTS

DPU Acts Against National Grid over Billing, Service Issues

The Department of Public Utilities last week took action against National Grid, limiting how much it can collect from customers after months of billing failures and fining the company millions of dollars for service issues in 2023.

The DPU told National Grid in its letter that it was not allowed to bill customers for several months of energy usage, saying, "For each customer who has not received a bill since the beginning of the peak season, the company shall waive charges for any usage occurring more than 60 days prior to the date the company sends the customer its next bill. For customers who did not receive a bill for more than 60 days, the company shall either waive collection of amounts owed for usage more than 60 days prior to the date of said bills or, if the customer has already paid, the company shall credit or refund such sums to each customer."

The DPU also fined National Grid $15 million "for service quality failures in 2023."

More: *WBTS*

MONTANA

Committee OKs Bill to Give Gov. Power to Appoint 3 PSC Members

A bill that aims to give the governor and the Senate the power to appoint and confirm three of the Public Service Commission's five members passed the Energy, Technology and Federal Relations Committee with a 9-4 vote.

Currently, all five members are elected by voters in five separate districts and can serve two four-year terms back-to-back. If the bill were to be signed into law, only two of the members would be elected by voters in the state's two congressional districts. The other three would be appointed by the governor and would need confirmation by two-thirds of the Senate.

A similar bill introduced in the House earlier this year failed to get out of committee.

More: *Billings Gazette*

PENNSYLVANIA

Scranton Approves 1st Solar Farm

The Scranton Zoning Board last week voted 3-2 to approve what will be the city's first commercial solar farm.

Bear Peak Power of Denver will construct the 3.2-MW farm with 6,580 solar panels on 13.7 acres.

Further reviews could take 12-18 months, with construction beginning after that. If so, it could be until late 2026 or early 2027 before the facility is operational.

More: *The Times-Tribune*

VIRGINIA

Mecklenburg County Favors Solar Project

The Mecklenburg County Planning Commission last week voted 7-5 to recommend a special exception permit for the 7 Bridges Solar project.

The 80-MW project is slated for 499 acres.

The recommendation advances to the county Board of Supervisors, which is expected to take up the matter May 12.

More: *SoVaNow.com*

WYOMING

PacifiCorp Changes Plans for Dave Johnston Coal Plant

PacifiCorp last week altered its plans for the Dave Johnston coal-fired power plant while solidifying plans to stop burning coal at the Naughton power plant by the end of this year.

Rather than fully retiring two of four coal-burning units at the Dave Johnston plant in 2028, the utility now plans to convert those units to natural gas in 2029 and continue their operation. A third coal unit will be shut down in 2027, as previously planned, and the fourth, which had no retirement date, will now be converted to natural gas in 2030.

The company's plans for the Jim Bridger plant and the Naughton plant didn't change. Two of four coal units at Jim Bridger were converted to natural gas last year, and the company still plans to retrofit the other two units there with carbon capture technology by 2030 or 2032. At Naughton, the first of three coal units was converted to natural gas in 2020. PacifiCorp confirmed it still plans to take the two remaining coal units offline by the end of this year and resume operating them on natural gas in 2026.

More: *WyoFile*