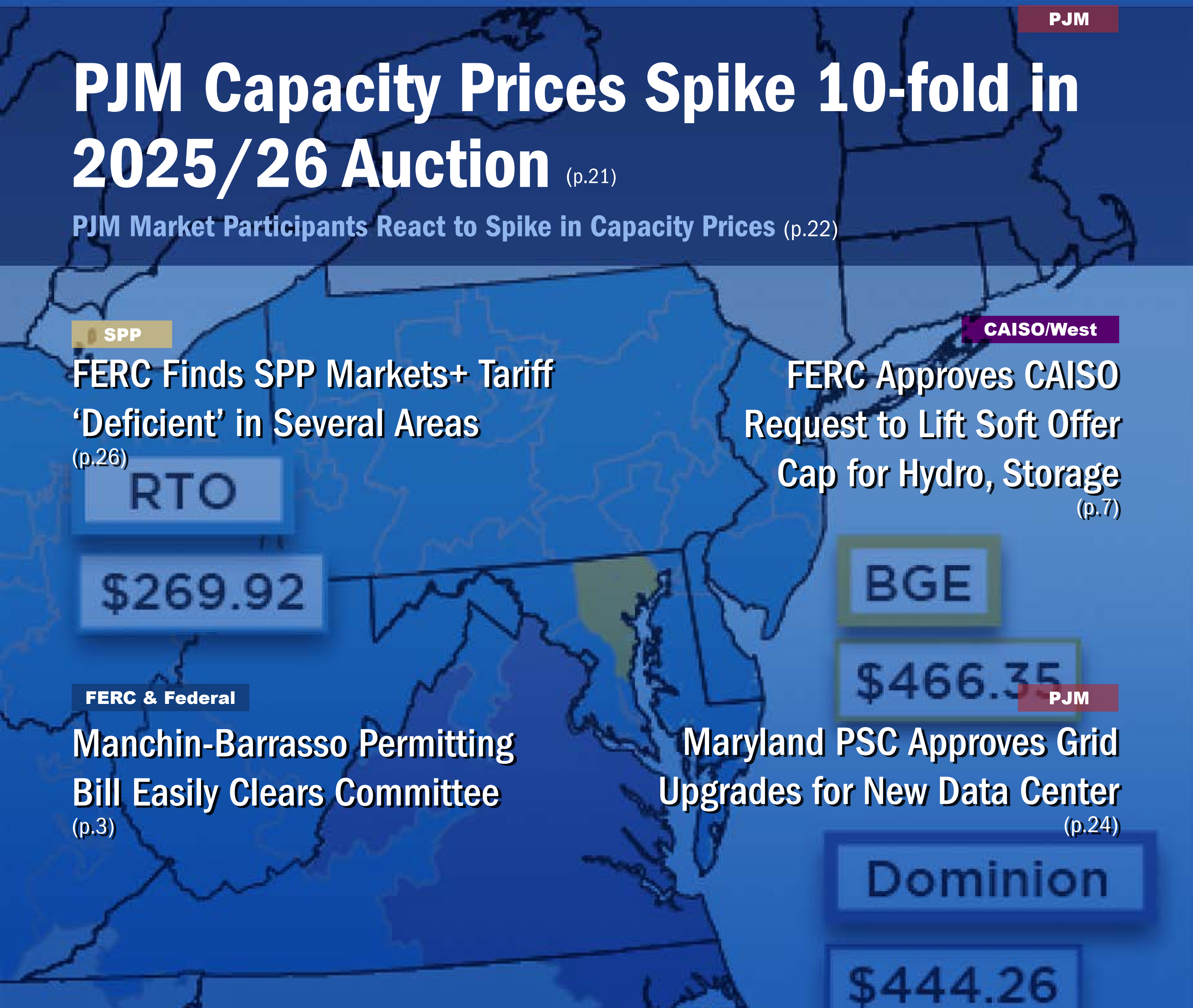
ISSN 2377-8016 : Volume 2024/Issue 31 ▪ August 6, 2024

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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



PJM

PJM Capacity Prices Spike 10-fold in 2025/26 Auction (p.21)

PJM Market Participants React to Spike in Capacity Prices (p.22)

SPP

FERC Finds SPP Markets+ Tariff 'Deficient' in Several Areas (p.26)

CAISO/West

FERC Approves CAISO Request to Lift Soft Offer Cap for Hydro, Storage (p.7)

FERC & Federal

Manchin-Barrasso Permitting Bill Easily Clears Committee (p.3)

PJM

Maryland PSC Approves Grid Upgrades for New Data Center (p.24)

COVER: PJM capacity prices increased nearly tenfold in the 2025/26 Base Residual Auction, with two regions reaching their zonal caps. *(Page 21) | PJM*

RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

Editor & Publisher
Rich Heidorn Jr.

Editorial

Senior Vice President
Ken Sands

Deputy Editor / Daily
Michael Brooks

Deputy Editor / Enterprise
Robert Mullin

Creative Director
Mitchell Parizer

New York/New England Bureau Chief
John Cropley

Mid-Atlantic Bureau Chief
K Kaufmann

Associate Editor
Shawn McFarland

Copy Editor / Production Editor
Patrick Hopkins

CAISO/West Correspondent
Ayla Burnett

D.C. Correspondent
James Downing

ERCOT/SPP Correspondent
Tom Kleckner

ISO-NE Correspondent
Jon Lamson

MISO Correspondent
Amanda Durish Cook

NYISO Correspondent
Vincent Gabrielle

PJM Correspondent
Devin Leith-Yessian

NERC/ERO Correspondent
Holden Mann

Sales & Marketing

Senior Vice President
Adam Schaffer

Account Manager
Jake Rudisill

Account Manager
Kathy Henderson

Account Manager
Holly Rogers

Director, Sales and Customer Engagement
Dan Ingold

Sales Coordinator
Tri Bui

Sales Development Representative
Nicole Hopson

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

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

FERC/Federal News

Manchin-Barrasso Permitting Bill Easily Clears Committee

By James Downing

The Senate Energy and Natural Resources Committee voted 15-4 on July 31 to advance the Energy Permitting Reform Act of 2024 to the floor.

The bill, *S.4753*, was backed by committee Chair Joe Manchin (I-W.Va.) and Ranking Member John Barrasso (R-Wyo.) and includes changes to transmission siting and planning, mining, oil and gas drilling, and judicial review.

The committee worked on the legislation over the course of this congressional session, holding many hearings on permitting and related issues, Manchin said at the committee's business meeting.

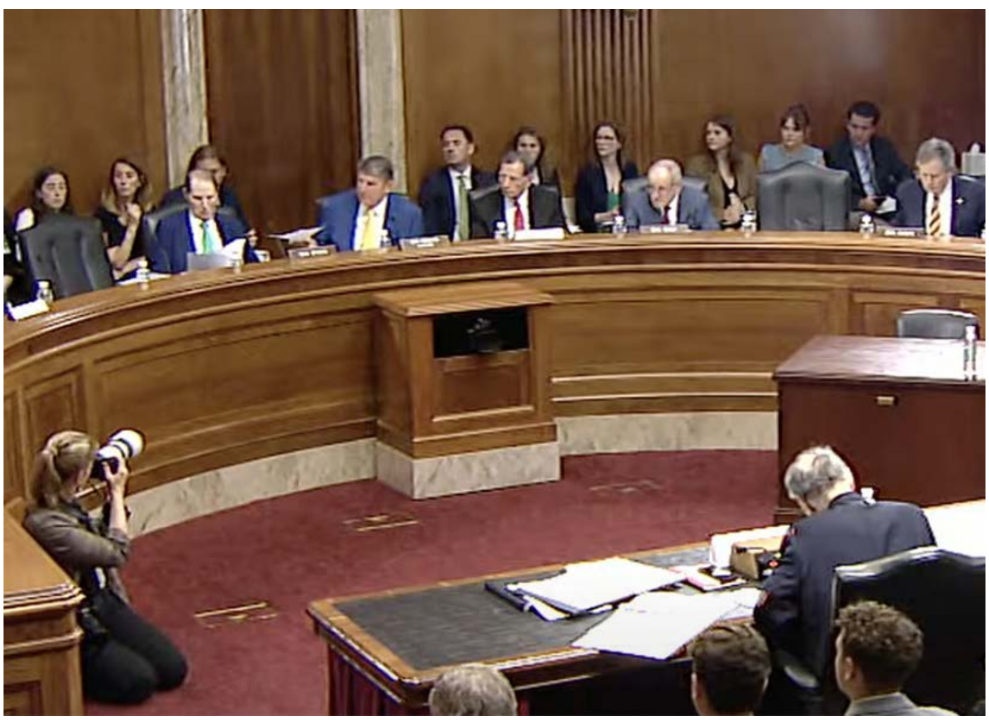
"I think the need for permitting reform has come up in almost every hearing that we've had this Congress," Manchin said. "No matter what side of the fence you may be on, everyone knows it can't happen unless we reform our permitting — how we do things. So, the time to act is now."

While the bill awaits a potential vote on the floor, the Senate's actual working days left this Congress are dwindling as lawmakers will take extended time off for the election this fall. The Senate leaves for summer break at the end of this week and is scheduled to be in session for only three more weeks before the election, with five weeks of a lame duck session on the schedule.

Numerous amendments were offered during the business meeting, but only one on forest restoration from Sen. Steve Daines (R-Mont.) passed. The committee voted down several others, including ones offered by Sen. Ron Wyden (D-Ore.) and Sen. Angus King (I-Maine) to ban offshore drilling off the West Coast and New England.

Sen. Josh Hawley (R-Mo.) offered the day's only amendment on transmission, which the main bill would give FERC authority to site. Hawley's amendment would have required any lines the commission sites to go through a regional planning process. Manchin said the language would threaten the existing backstop siting FERC implemented with Order 1977 and the committee rejected the amendment.

Other amendments, including one offered by Sen. Lisa Murkowski (R-Alaska) to make it easier for remote communities in her state to use small-scale hydroelectric and hydrokinetic generation, were withdrawn with promises from Manchin that changes could be made on the floor.


The Senate Energy & Natural Resources Committee during the business meeting where it advanced the Energy Permitting Reform Act of 2024. | *Senate Energy & Natural Resources Committee*

"After more than a year of bipartisan negotiations with Chairman Manchin, we are now one step closer to getting the bipartisan Energy Permitting Reform Act signed into law," Barrasso said. "Our bill is a true, all-of-the-above energy policy — targeted, timely and good for all Americans."

American Clean Power Association CEO Jason Grumet welcomed the bill, which he said would increase the resilience of the power sector and accelerate the deployment of clean energy.

"The leadership from the Senate Energy and Natural Resources Committee is critical to ensure that our nation can meet rapidly growing electricity demand," Grumet said. "The legislation is both bold and balanced, creating an effective policy framework for building new high-voltage transmission. Building out new transmission will help ensure affordable, reliable energy for American businesses and consumers."

The transmission language in the bill includes some language backed by Democrats and even environmentalists, with the House Sustainable Energy and Environmental Coalition's Reps. Sean Casten (D-Ill.) and Mike Levin (D-Calif.) welcoming those provisions. The two have introduced the *Clean Electricity and Transmission Acceleration Act*, which includes similar transmission reforms.

"While there are aspects of the bill that can be improved upon and provisions that we have concerns about, we are eager to continue the critical discussion on permitting reform as we strive to enact a law that will equitably accelerate adoption of clean energy and transmission," Casten and Levin said in a statement.

The Sierra Club found its opposition to the offshore drilling language and changes to permitting on federal law outweighed whatever benefits the transmission language would bring, saying it preferred the Casten-Levin legislation in the House.

"There are existing proposals that would offer real solutions to accelerate the deployment of clean energy without sacrificing the climate and public health for fossil fuel executives' profits," Sierra Club Beyond Fossil Fuels Policy Director Mahyar Sorour said in a statement. "It is possible, and necessary, to unleash renewable energy and supercharge the clean economy without undermining bedrock environmental laws. Congress must see through this ruse to give handouts to polluters and reject the Dirty Deal." ■

FERC/Federal News

RMI Report Urges States to Adopt Performance-based Regulation

Economic Regulations Aim to Align Utility Incentives with Customer, Societal Needs

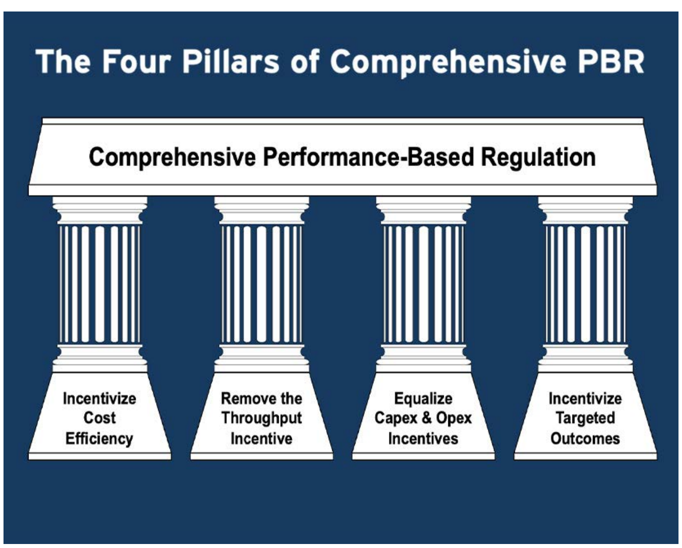
By James Downing

Performance-based regulation is a way to align utility incentives with the interests of customers and society, according to a new RMI report that seeks to get more states to adopt the practice over traditional cost-of-service regulation.

Traditional regulation has strong financial incentives for utilities to spend more money than needed on infrastructure, leading to affordability concerns as the industry invests to transition to a modern, cleaner grid, said the *report*, titled "How to Restructure Utility Incentives: The Four Pillars of Comprehensive Performance-Based Regulation."

"There's a number of reasons the traditional model just isn't really well aligned with the challenges today," report co-author Kaja Rebane, an RMI senior associate, said in an interview. "Affordability is a very big one of those. Right now, we are facing the need to invest a lot of money in the grid [to] modernize it, to deploy new technologies and to just build more capacity to supply clean power to customers."

Traditional regulation pays utilities for what they build, while performance-based regulation (PBR) focuses on what they achieve, she added. Utilities will consider a number of factors when they make investments, but regulations guaranteeing them a return on capital are a major influence.



| RMI

"That's not ... well-aligned with what the challenge is today," Rebane said. "We do need more capital spending that is important, but we need it to be cost-efficient in order to achieve what we want to achieve in an affordable manner."

Getting the right regulatory incentives sounds easier than it is because a full suite of performance-based regulations requires multiple changes to the cost-of-service model. The report said regulators can do "incremental PBR" and adopt some specific tools onto traditional regulation, or "comprehensive PBR," adopting the full suite of reforms to get utilities focused on outcomes in ways cost-of-service regulation cannot.

The report lays out four pillars of performance-based regulation: incentivize cost efficiency, remove the throughput incentive, equalize capital and operational spending incentives, and incentivize targeted outcomes.

Cost efficiency can be supported by an array of changes, such as multiyear rate plans, shared savings mechanisms, fuel-cost sharing mechanisms and metrics focused on spending trends.

Revenue decoupling is the main way to remove the throughput incentive, while equalizing returns for capital and operational returns is self-explanatory. Incentivizing targeted outcomes can be accomplished through metrics, scorecards and performance incentive mechanisms (PIMs).

"Although PBR can be powerful, it is not a silver bullet for every regulatory problem," the report said. "Even a well-designed comprehensive PBR framework will achieve the best results when it is part of a larger basket of synergistic reforms, such as widening opportunities for stakeholder input, adopting innovation policies, updating planning and procurement processes, and expanding regulatory commission authority and responsibilities."

PBR in Hawaii

The report highlights Hawaii as a jurisdiction that has adopted comprehensive PBR across the four pillars.

"We highlighted Hawaii, in part, because it really has adopted a framework we would consider comprehensive, meaning that all four pillars that we discussed in the report are supported," Rebane said. "There's also been a number of forward-looking reforms in Hawaii that are worth highlighting."

Hawaii has a five-year multiyear rate plan (MRP) with returns pegged to third-party indexes instead of utility forecasts, she added.

To mitigate excessive earnings or losses, the five-year rate plan comes with an earnings-sharing mechanism with a wide symmetrical deadband to ensure cost efficiency, the report said.

"Because of the deadband, which is centered around an allowed ROE of 9.5%, the MRP's full cost-containment incentive is preserved (i.e., Hawaiian Electric keeps all additional earnings and bears all deficits) when the realized ROE falls between 6.5 and 12.5%," the report said. "Outside of the deadband, sharing ramps up in a tiered fashion."

A shared savings mechanism encourages cost efficiency for operational costs not covered by the annual revenue adjustment in the rate plan, which covers fuel for generators, purchased energy and capacity costs, new projects not funded with the rate plan, and other items. A fuel-cost sharing mechanism trues up just 98% of the difference between expected and actual costs — subject to a $2.5 million annual cap, which gives Hawaiian Electric the incentive to operate its generation more efficiently.

Hawaii regulators have also adopted metrics and scorecards that provide visibility into the utility's cost trends, which include rate base per customer, operations and maintenance cost per customer, and annual revenue growth.

The term performance-based regulation has been around a while, and RMI hopes its report will help regulators better understand what it means and how it can improve outcomes in their jurisdictions, Rebane said.

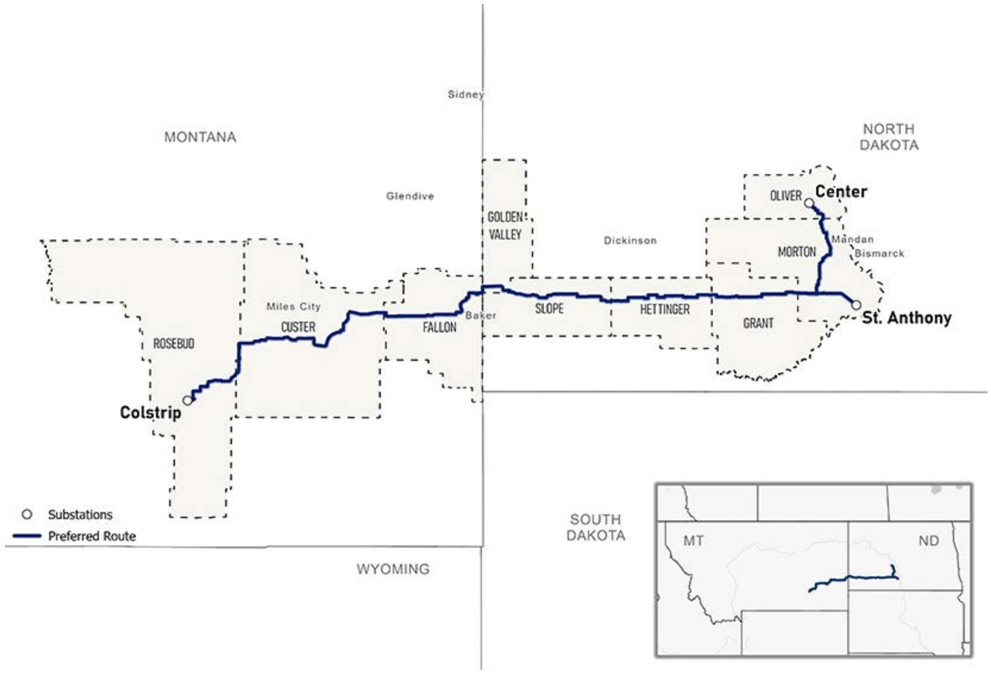
"We're trying to give regulators the tools they need to really reform incentives in their jurisdictions to achieve their policy goals," Rebane said. "We also, of course, in the report provide kind of a relatively basic overview of a number of the key PBR tools that can support each pillar and so, hopefully, that will provide something of a go-to reference for regulators who are interested in these things." ■

FERC/Federal News

DOE Announces $2.2B in Grid Resilience, Innovation Awards

2nd Round of GRIP Funding Goes to New Lines, GETs Projects

By K Kaufmann



The North Plains Connector transmission project running from Montana to North Dakota is getting a $700 million GRIP award. | *Grid United*

The U.S. Department of Energy on Aug. 6 announced its second round of grants for the Grid Resilience and Innovation Partnerships (GRIP) program, with $2.2 billion in federal dollars going to eight projects that could expand grid capacity, reliability and flexibility across 18 states.

Funded with $10.5 billion from the Infrastructure Investment and Jobs Act, the *GRIP program* is aimed at supporting "transformative" projects that will "enhance grid flexibility and improve the resilience of the power system against growing threats of extreme weather and climate change," according to DOE.

Announced in October, the first round of awards totaling $3.46 billion was focused primarily on improving grid resilience against extreme weather events at the distribution level, Energy Secretary Jennifer Granholm said during an Aug. 5 press briefing. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

The second tranche announced Aug. 6 is "specifically focused on transmission lines themselves, building more than 600 miles of new lines and reconductoring more than 400 miles of existing lines," Granholm said. "Altogether, those upgrades are going to add nearly 13 GW of capacity to the grid … to meet the needs of electrified homes and businesses and new manufacturing facilities and all of these growing data centers that are placing demands on the grid. …

"The first half of 2024 has already broken records for the hottest days in Earth's history, and as extreme weather continues to hit every part of the country, we must act with urgency to strengthen our aging grid to protect American communities," Granholm said in a DOE press release.

According to DOE, six of the projects will be using the GRIP grants to deploy grid-enhancing technologies (GETs) to expand capacity on existing lines. For example, California is getting more than $600 million to upgrade 100 miles of transmission with advanced conductors and dynamic line rating technology to increase the amount of renewable energy on the grid.

Similarly, a $57 million GRIP award will go to the North Carolina Department of Environmental Quality, which will partner with Duke Energy to upgrade a key transmission line with advanced conductors that will increase capacity and improve resilience as electricity demand continues to grow in the eastern part of the state.

Advanced conductors have a stronger core that can operate at higher temperatures than traditional grid lines, which allow them to carry more power. Dynamic line rating technologies allow grid operators to determine how much power a line can transmit based on real-time conditions rather than using a preset, static rating.

Of the projects building out new lines, Montana was selected to receive the largest award, $700 million, to support the North Plains Connector (NPC), a 415-mile HVDC line running from Montana to North Dakota. It will be the first transmission project that will connect three regions — MISO, SPP and the Western Interconnection — with bidirectional power flows that could open up 3,000 MW of new capacity, as detailed in DOE's project description.

The project will also help the Standing Rock Sioux Tribe develop wind power on their land.

That broad regional coverage could provide benefits by connecting meteorologically diverse regions that have demand peaks at different times of the day or in different seasons, according to a recent study by Astrapé Consulting. The difference in generation and load profiles could improve the grid's reliability on both sides of the project without adding any new capacity, project developer Grid United said. (See *Study: Significant Benefits for Merchant Tx Line*.)

All GRIP awards are supported by public-private partnerships, with individual states and their commercial partners at least matching or exceeding the federal funds. The $700 million for NPC is being matched with close to $2.9 billion in other funding, according to DOE.

DOE estimates the projects will create about 5,000 jobs, with six of the eight projects partnering with local labor unions.

Getting GRIP Projects Permitted

Other GRIP awards will support initiatives that tackle critical grid challenges, including responding to rapidly growing demand from data centers and connecting offshore wind projects to onshore lines.

Home to the greatest concentration of data centers in the country, Virginia is receiving $85.5 million for a project that will build up distributed energy resources at data centers

FERC/Federal News

to provide flexible power to the grid. The funds will go to install battery energy storage systems at the Iron Mountain data center in Manassas, Va., and to deploy solar, storage and a natural gas turbine at the Grace Complex, an industrial innovation hub being developed in Lancaster, S.C.

A $389.3 million grant is going to Power Up New England, a joint project of six new England states, ISO-NE and public utilities that will provide new substations in Southeast Massachusetts and Southeast Connecticut to connect up to 4,800 MW of offshore wind power to the onshore grid. And Northern Maine will get a long-duration energy storage system with multiday capacity to improve grid resilience and the integration of renewable energy.

"With Power Up, we are shifting the way we bring offshore wind into our grid," said Rebecca Tepper, Massachusetts' secretary for energy and environmental affairs. "We've done the hard work to coordinate with ISO New England and developers to ensure we're making smart, targeted investments to ready our electric grid."

Speaking at the Aug. 5 press briefing, both Granholm and National Climate Advisor Ali Zaidi said Power Up and other GRIP projects would benefit from DOE's efforts to streamline and accelerate federal permitting processes, such as the Coordinated Interagency Authorizations and Permits (CITAP) program announced in April.

Under the initiative, DOE will take the lead on permitting transmission projects and coordinate environmental and permitting processes between federal agencies, with a goal of limiting permitting timelines to two years. (See *DOE CITAP Initiative Aims to Permit New Transmission in 2 Years*.)

Reconductoring projects may be eligible for categorical exclusions, the lightest level of environmental review, under *revisions* to permitting rules DOE released also in April, providing "a permitting ecosystem that has been vastly improved," Zaidi said.

Responding to a reporter's question, a senior DOE official declined to speculate on the potential impact of the bipartisan permitting bill authored by Sens. Joe Manchin (I-W.Va.) and John Barrasso (R-Wyo.), respectively the chair and ranking member of the Senate Energy and Natural Resources Committee.

The Energy Permitting Reform Act of 2024 would increase FERC's power to authorize new transmission projects and require interregional transmission planning. The bill passed the committee on a 15-4 vote on July 31, days before Congress adjourned for its August recess. The Senate will have three weeks to pass the bill before Congress again goes into recess for the election. (See *Manchin-Barrasso Permitting Bill Easily Clears Committee*.)

DOE favors removing barriers to permitting and accelerating the ability to do concurrent environmental reviews, the official said, adding that the department is even doing a pilot on using artificial intelligence on permitting.

A third round of GRIP awards will be announced this year or early in 2025 for two other programs under the initiative, DOE said. The Grid Resilience Utility and Industry Grants will target private sector efforts to upgrade the grid, and Smart Grid Grants will support technologies that expand grid capacity. ■

CAISO/West News

FERC Approves CAISO Request to Lift Soft Offer Cap for Hydro, Storage

By Ayla Burnett

FERC on July 31 accepted CAISO's proposal to allow for storage resources to bid above the ISO's $1,000/MWh soft offer cap in the real-time market to account for their intraday opportunity costs (*ER24-2168*).

The approved tariff revisions also remove the requirement that scheduling coordinators submit reference level adjustment requests (RLCR) to raise their default energy bids (DEBs) above $1,000/MWh when their DEBs would, by their own calculations, rise above $1,000/MWh.

The proposal is the result of work by CAISO's Price Formation Enhancements Working Group and the Storage Bid Cost Recovery and Default Energy Bids initiative. It revises the process under FERC Order 831 by which the ISO verifies a unit's cost-based offers in the energy market. (See *CAISO Moves for Expedited Change to Soft Offer Cap*.)

View of the Tehachapi Energy Storage Project in Tehachapi, Calif. | *Sandia National Laboratories*

Issued in 2016, Order 831 set a "soft" cap on energy bids of $1,000 that could be exceeded, up to a "hard" cap of $2,000, to reflect a resource's verifiable costs. Each grid operator was required to propose a process for verifying offers over the soft cap.

CAISO, however, found that the new paradigm, approved in 2020, inhibited storage and hydroelectric resources, two types vital to maintaining adequate supply during the summer.

"For resources that operate based on finite resources like reservoir levels or state-of-charge, supplying energy earlier in the day often means that they cannot supply energy later at the time of higher demand," FERC said in its order. "CAISO states that this is a significant concern because if these resources are depleted earlier in the day, CAISO must depend on a more limited pool of resources to meet its later net peak demand."

Removing the RLCR restriction will enable cost-justified bidding, promoting more efficient dispatch on constrained days, FERC said. "The artificial restriction to cap DEBs at $1,000/MWh is unnecessary and counterproductive to using DEBs for cost-verification."

CAISO's Department of Market Monitoring agreed, having argued that requiring scheduling coordinators to submit RLCRs is unnecessary because the formulas used to calculate DEBs are well established and reflect the marginal cost of a resource. The department also agreed the cap should be removed for energy-limited resources because of the technical limits they face. Portland General Electric and the California Energy Storage Alliance also supported the proposal.

While the DMM generally supported the tariff revisions, it also said the proposed changes should not apply to the entire day because a static bid cap cannot target specific hours when intraday opportunity costs are most likely to exceed $1,000/MWh.

The California Public Utilities Commission also argued that the proposed changes are not targeted enough to address the intraday opportunity costs of hydro resources. Lifting the cap in the day-ahead market is not necessary because the market is already able to optimize resource schedules, it said.

"DMM and CPUC assert that the bid cap proposed by CAISO would allow energy storage resources to bid substantially in excess of their intraday opportunity costs during high priced hours when the system is tight and the opportunity cost is known to approach zero," FERC summarized.

The department also raised concerns about the tariff revisions' potential to exacerbate existing flaws in bid cost recovery, an issue being addressed in the ISO's bid cost recovery initiative. (See *CAISO Kicks Off Storage Bid Cost Recovery Stakeholder Initiative*.)

The CPUC also argued that the hydro DEB formula was not designed for above-cap bidding and therefore does not result in values that satisfy Order 831 cost justification requirements.

CAISO responded by reiterating its belief that artificially capping any resource's DEB at $1,000/MWh in the day-ahead market could lead to inefficient scheduling. CPUC's arguments regarding the hydro DEB formula were outside the scope of the proceeding, the ISO argued, and neither it nor the DMM provided evidence that proposing a static bid cap throughout the day rather than targeting specific hours was unreasonable.

FERC disagreed with the DMM's and CPUC's arguments.

"We find that CAISO's proposal will help to ensure that energy-limited resources are able to reflect their opportunity costs in their cost verified bids, similar to other resources," FERC stated. "We find that accounting for these opportunity costs will enable CAISO to more optimally manage these resources' energy limitations over the day, and thereby improve CAISO's ability to reliably and economically meet its net peak demand."

The tariff revisions become effective Aug. 1. Commissioners Lindsay See and Judy Chang did not participate in the order. ■

CAISO/West News

WEIM Yields $365M in Q2 Benefits with Hot Start to Summer

CAISO Leading Exporter During Quarter, Followed by PacifiCorp, NV Energy

By Robert Mullin

CAISO's Western Energy Imbalance Market (WEIM) provided its 22 participants with $365.04 million in economic benefits from April to June this year, down 4% from the same period a year ago.

Cumulative benefits since the 2014 launch of the real-time market have hit $5.85 billion, according to CAISO's second-quarter WEIM benefits *report*, released July 30.

June saw an extremely hot start to summer for most of the West. During that month, the solar-heavy CAISO area was the WEIM's leading net exporter, sending more than 1.1 million MWh of energy to other market participants, up 7% from June 2023. In the WEIM, a net export represents the difference between total exports and total imports for a balancing authority area during a particular real-time interval.

"The transfers helped balance supply and demand when some of the WEIM entities were experiencing higher electricity usage due to a heat wave that saw temperatures climb 7 to 16 degrees above normal for several days across the West," CAISO said in a *press release* accompanying the report.

The ISO was also the biggest net exporter over the full quarter at 2.86 million MWh, followed by PacifiCorp's East and West BAAs' combined exports of 584,555 MWh, NV Energy at 464,133 MWh and Salt River Project at 395,542 MWh.

The largest net importers were Powerex (965,287 MWh), the Balancing Authority of Northern California (BANC) (534,382 MWh) and SRP (473,319 MWh).

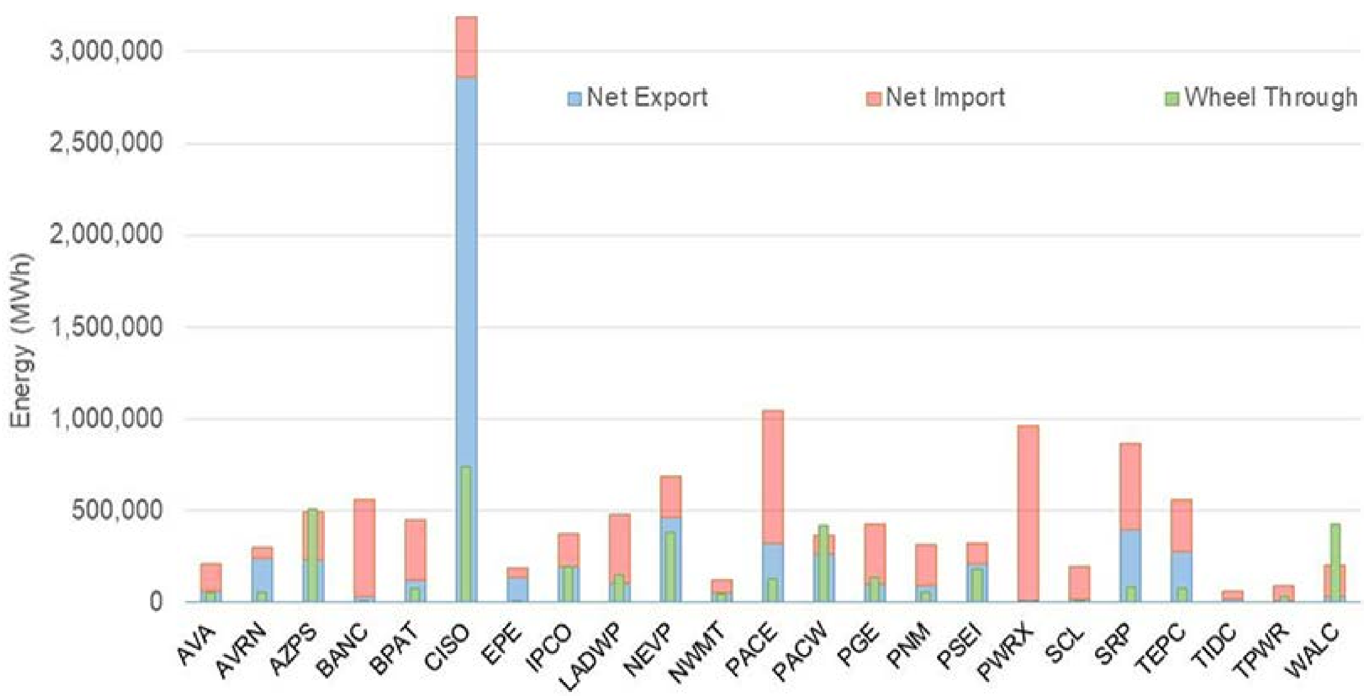
CAISO was also the location of the largest volume of wheel-through transfers during the quarter at 736,433 MWh, followed by Arizona Public Service (508,707 MWh), the Western Area Power Administration's Desert Southwest Region (DSW) (430,880 MWh) and PacifiCorp-West (419,025 MWh). WEIM participants currently receive no financial benefits from facilitating wheel-throughs through the market, with only the source and sink of the transfers benefiting, although stakeholders have discussed the possibility of changing that in the future.

"More recently, subsequent to the June 30 closing of the second quarter, the real-time market also provided an important platform for energy trading during the record-setting heat wave in July that caused triple-digit temperatures across much of California and the West," the ISO said. "Market participants provided similar assistance with robust energy transfers throughout the region."

DSW, which joined the WEIM in 2023, reaped the greatest economic benefit during the second quarter, at $50.57 million. DSW this year withdrew from participating in the second phase of developing SPP's Markets+ — a potential competitor to the WEIM — after finding it would see few benefits from participating in either Markets+ or CAISO's Extended Day-Ahead Market. (See *WAPA DSW Cites Lack of Benefits in Markets+ Withdrawal*.)

BANC realized the second-largest share of benefits ($49.9 million), followed by CAISO ($36.02 million), NV Energy ($33.65 million) and the Los Angeles Department of Water and Power ($30.52 million).

CAISO's report said WEIM operations in the third quarter also helped market participants avoid 55,921 metric tons of greenhouse gas emissions through reduced curtailments of emissions-free resources. The market has prevented over 1 million MT of emissions since 2015, the ISO estimates. ■



CAISO was by far the WEIM's largest energy exporter during the second quarter and the site of the highest volume of wheel-throughs between participant balancing authority areas. | CAISO

CAISO/West News

'Operational Surprises' Contributed to CAISO July 2023 Emergencies

ISO's Market Surveillance Committee Points to Problems with Flexiramp Product, HASP

By Ayla Burnett

CAISO's own systems may have contributed to a set of "operational surprises" that forced it to declare a series of energy emergency alerts in July 2023, a member of the ISO's Market Surveillance Committee (MSC) said July 30.

"It is our understanding that CAISO/Western EIM operators were surprised by near-real-time changes in the CAISO/Western EIM supply demand balance on July 20 and July 25, 2023," MSC member Scott Harvey, a consultant at FTI Consulting, said during a presentation at the MSC's monthly meeting. "There are also indications that CAISO systems and operator actions may have contributed to operational surprises for Western EIM balancing area operators."

High levels of self-scheduled exports out of CAISO's balancing area to support stressed conditions in other parts of the West prompted the ISO to issue an EEA 1 on July 20 and EEA watches on July 25 and 26. (See *CAISO DMM: High Exports to Southwest Led to July EEAs*.)

On July 20, CAISO was close to being unable to deliver exports that had received hour-ahead awards, though no load was ultimately curtailed. But on July 25, the ISO was unable to award several thousand megawatts of self-scheduled exports.

As a result, CAISO imposed import limits from the WEIM into the CAISO balancing authority area between July 25 and Nov. 16, leading to increased transmission congestion in the 15-minute market and lower prices in the five-minute market, the ISO's Department of Market Monitoring said in March. (See *DMM: CAISO Transfer Limitations During Q3 Heatwaves Led to Price Disparities*.)

Although the DMM previously said it was unclear why CAISO chose to implement transfer limits through November, Guillermo Bautista Alderete, CAISO's director of market performance and advanced analytics, provided additional color by identifying two key market issues. The first, he said, was an inaccurate display of dispatchable capability in the market, where information presented to operators showed an imprecise calculation of storage resources, impacting operators' ability to take proactive action.

"One of the purposes of that display and that information is to project how the ramp capabilities position for the near future," Alderete said. "If they see that the ramp capability is getting thinner and thinner, they may start taking action rather than applying load conformance."

The second was related to scheduling and tagging processes. When clearing transactions in the WEIM between Oregon and California, a change in practice led to double counting, which exacerbated congestion and kept flexible ramping product (FRP) "stranded in the north."

Additionally, export reductions projected in the hour-ahead scheduling process (HASP) led to uncertainties in the real-time market due to exports not materializing.

"We had about 2,400 megawatts of additional demand that HASP was not projected as having to meet, and now the [real-time dispatch] has to meet that extra obligation in real-time," Alderete said.

The issues weren't fully addressed until Nov. 16, when the ISO stopped imposing transfer limits.

MSC Questions Flexiramp, HASP Structure

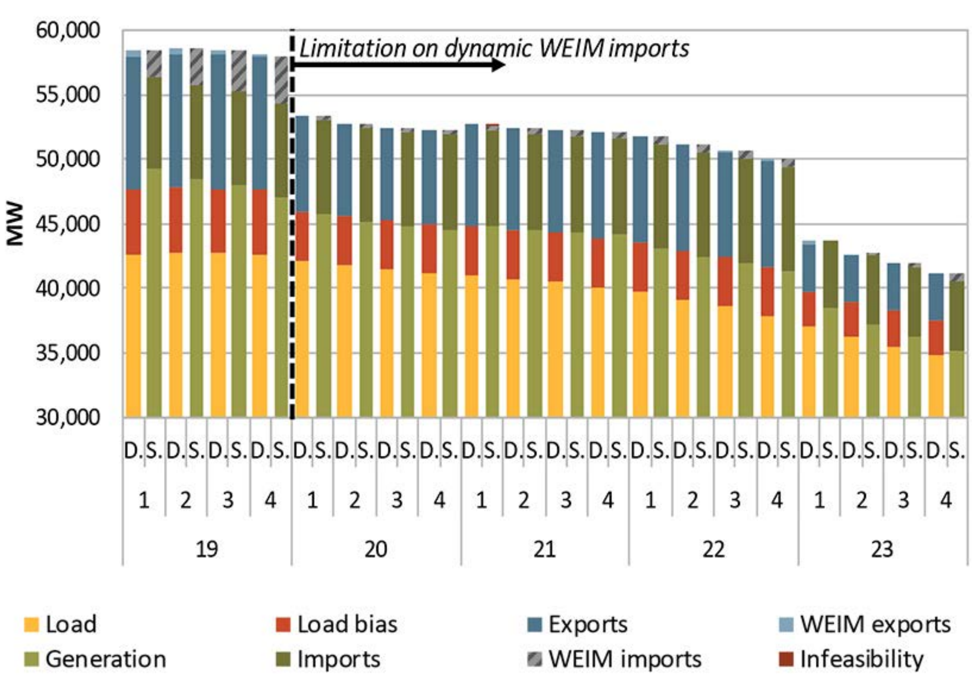
The "operational surprises" associated with July's events also included problems identified with HASP and CAISO's flexible ramping product (flexiramp).

While the role of HASP has "evolved dramatically" since it was implemented in 2014, the structure has not, Harvey said.

The HASP originated as a tool to schedule interchange transactions between CAISO and adjacent balancing areas in conjunction with the scheduling of CAISO balancing area resources. While HASP still serves that role, it "has developed into an hourly spot market for the purchase of capacity to meet the [WEIM's] resource sufficiency evaluation," Harvey said.

In 2014, almost all imports and exports scheduled in HASP were with balancing areas that didn't belong to the WEIM. As of July 2023, nearly all imports and exports scheduled in HASP sourced or sank within the EIM.

As a result, stakeholders questioned the implications of the resource sufficiency evaluation of HASP transactions included in WEIM base schedules but not clear in HASP.



CAISO imposed transfer limitations in July 2023 as a result of bad weather conditions outside of California. | *CAISO*

CAISO/West News

"A core issue is that when CAISO clears HASP to schedule hourly interchange between ... CAISO and other Western EIM balancing areas, day-ahead market exports that do not clear in HASP improve the CAISO resource balance relative to the day-ahead market, appearing to increase supply in both ... CAISO and the Western EIM," Harvey's presentation said.

"However, market exports that do not clear in HASP may be included in the base schedules of EIM entities," it said. "The current HASP structure models the improvement in CAISO supply when day-ahead exports do not clear but does not model the potential reduction in Western EIM supply. Hence, HASP can appear to show a supply demand balance in the Western EIM when there actually is a large supply gap."

If WEIM entities find out only after HASP posts that exports included in their base schedules will not flow in real time, they will have less time to take remedial action, as was the case in July.

"It seems that this HASP structure is creating an information problem, that it isn't set up to tell us the truth for the Western EIM," Harvey said. "It's going to tell the truth for what the CAISO needs to do to avoid load shedding in terms of having supply that it can point to, but it isn't looking necessarily at … the big picture."

Harvey also questioned the effectiveness of flexiramp and pointed to its potential to create more "operational surprises." In the case of July's events, flexiramp product couldn't reach CAISO's balancing area due to congestion.

"If we're going to reduce the load conformance, we have to make sure that the flexiramp is deliverable, and it looks to me like part of the problem on the 20th was that it wasn't," Harvey said.

Additionally, flexiramp is designed only to cover net load uncertainty and does not procure capacity in real time to cover all types of supply changes, such as those that occurred in July.

To avoid another emergency event, Alderete highlighted a few ways CAISO could improve.

"We have realized there needs to be better awareness for operators to get a sense of the wider picture, how many transfers they have and potentially give them more confidence of how much of those could be realized," Alderete said.

Staff also took steps to increase transparency, including using market messages to communicate information on transfer limits.

"We realized that we could have communicated better, and I think we can do better for whenever the next time is going to be," Alderete said. ■

ERCOT News

ERCOT Evaluating RMR, MRA Options for CPS Plant

San Antonio Utility Retiring 859 MW of Coal Generation in 2025

By Tom Kleckner

ERCOT has issued a *request for proposal* seeking alternatives to a reliability-must-run contract with CPS Energy, compensating for the utility's planned retirement of a power plant.

The ISO said in a July 25 *market notice* that CPS Energy's decision to retire three aging coal-fired units, with a combined summer seasonal net maximum sustainable rating of 859 MW, would have a "material impact on identified ERCOT system performance deficiencies." The grid operator's staff has said the units' retirement would load existing transmission facilities above their normal ratings under pre-contingency conditions.

ERCOT's determination triggered the grid operator's obligation to issue an RFP for must-run alternatives (MRAs) and begin RMR negotiations with CPS Energy. The San Antonio utility has proposed suspending the three V.H. Braunig units after March 2025. (See *CPS Energy Plans to Retire 859 MW of Gas Resources*.)

Qualified scheduling entities (QSEs) can submit proposals for one or more MRA resources to address system performance deficiencies more cost effectively than by committing one or more Braunig units through a more expensive RMR contract. QSEs can offer the resources for one or more seasons during April 1, 2025, through March 31, 2027. Eligible resources include types of generation, storage and demand response.

RFP offers are due Sept. 9. ERCOT will host a workshop Aug. 15 to discuss the RFP and answer questions. After reviewing all proposals, staff will make a recommendation to the ISO's board during its October meeting.

An RMR contract would be ERCOT's first since 2016. The grid operator entered into an agreement with NRG Texas Power over a previously mothballed gas unit near Houston. The RMR contract ended in 2017, thanks partly to transmission facilities that increased imports into the region. (See *ERCOT Works to Address Loss of San Antonio Units*.)

$24.4B in Energy Fund Requests

The Public Utility Commission said July 29 it has received 72 applications for loans through the *Texas Energy Fund*'s in-ERCOT Generation Loan Program. The applications request $24.41 billion to finance 38.37 GW of proposed dispatchable, or thermal, power generation.

Lawmakers have set aside $5 billion for this TEF program, one of four.

"Texans have made it clear that they expect reliable electricity today and well into the future, and I am pleased to see industry leaders responding to that call and planning for major investments in dispatchable power for the state," PUC Chair Thomas Gleeson said in a *news release*.

Commission staff will evaluate the applications before the commission determines which projects will proceed to due diligence during the PUC's Aug. 29 open meeting. The in-ERCOT program will provide low-interest loans to finance up to 60% of new construction or upgrades to existing dispatchable facilities. A proposed project must add at least 100 MW of new generation to the ERCOT grid to be eligible. Approved loans' initial disbursements will be issued by Dec. 31, 2025.

The in-ERCOT program and three other TEF programs were established in March because of *state legislation* passed last year. The PUC says the program can support up to 10 GW of new or upgraded generation capacity in ERCOT. (See *Texas PUC Establishes $5B Energy Fund*.) ■

CPS Energy plans to retire three units at its V.H. Braunig facility. | *CPS Energy*

ERCOT News

ERCOT Technical Advisory Briefs

Staff Implement ECRS Changes, Withdraw Related NPRR

ERCOT staff have withdrawn a protocol change and updated control room procedures following the regulatory commission's rejection of modifications to the grid operator's new ERCOT contingency reserve service (ECRS) product.

The Public Utility Commission on June 25 rejected the nodal protocol revision request (*NPRR1224*) by removing the proposed $750/MWh price floor and directing ERCOT to separately implement the revision's trigger mechanism for the service. (See *Texas Commission Rejects ECRS Rule Change*.)

"I think my lawyers would say that they did not direct us to do anything, but that they expressed some support for the concept of releasing ECRS when we hit the triggers that were described, so we're going to roll with that," ERCOT's Jeff Billo, director of operations planning, told the Technical Advisory Committee during its July 31 meeting.

Staff and stakeholders had been working since late last year to reach a compromise on NPRR1224. Stakeholders added the price floor for ECRS's deployment. The trigger mechanism takes effect when there is a 40-MW power balance violation for at least 10 minutes.

ERCOT *introduced ECRS last year*. It procures capacity resources that can be brought online within 10 minutes and sustained at a specified level for two consecutive hours. The Independent Market Monitor has opposed the new ancillary service, saying it produced "massive" inefficient market costs totaling more than $12 billion in 2023. (See *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)

Billo said ERCOT has updated its real-time desk procedures to incorporate the trigger mechanism, which became effective Aug. 1.

The grid operator also withdrew *NPRR1232*, which staff had begun developing during the NPRR1224 negotiations. Billo said after the PUC's discussion of NPRR1224's price floor and stakeholders' concerns over NPRR1232's implementation and timeline, staff decided to withdraw the latter and its similar price floor concept.

Staff discussed NPRR1232's withdrawal with the IMM, Billo said. He said he understood the monitor was "agreeable" with the withdrawal.

ERCOT's Jeff Billo (back) briefs TAC on staff's plans to implement PUC's direction on ECRS. | *ERCOT*

$29M in Firm Fuel Service

ERCOT staff told TAC it procured 3,319.9 MW of firm fuel supply service (FFSS) capacity with a projected standby cost of $29.88 million between Nov. 15, 2023, and March 15, 2024.

The grid operator contracted with 32 generation resources at $9,000/MW. Three of those either tripped offline during a watch or had mechanical failures unrelated to fuel or cold weather, leading ERCOT to claw back $976,818 from the resources. The clawback was offset partly by $781,342 in fuel replacement costs, resulting in a total FFSS payment of $29.42 million.

The *FFSS ancillary service product* is a result of legislative requirements and a PUC order to provide additional grid reliability and resiliency during extreme cold weather and compensate generation resources that meet a higher resiliency standard. Under ERCOT protocols, staff will provide a report to TAC when the product is deployed.

The ISO issued a *request for proposal* for FFSS during the next obligation period (Nov. 15, 2024-March 15, 2025) on July 31.

In other staff reports:

- Matt Mereness told TAC that ERCOT's highly anticipated real-time co-optimization (RTC) and battery project expects to announce a go-live date by the end of September. The project's tentative go-live date is 2026. In September, staff will simulate RTC, covering data from June 2023 onward, using their simulator for feedback on price formation.
- Bill Blevins, who chairs the Large Flexible Load Task Force, said more than 5 GW of load has been authorized and is waiting to be energized. The task force has discussed going into hibernation; members raised concerns over dissolving the group because they value the interconnection queue updates.

$272.6M Project Endorsed

TAC endorsed a $272.6 million regional project in Central Texas by adding it to the combination ballot. The Tier 1 project, requiring board approval, would address thermal violations in the Temple and Killeen area between Austin and Waco.

ERCOT staff said the Oncor Temple Area Regional Planning Group Project improves long-term load-serving capability, is the least-cost solution and requires the least amount of a certificate of convenience and necessity for the options that meet all ISO and NERC reliability criteria.

Oncor originally proposed a smaller project, but ERCOT staff's study found additional thermal and voltage violations and recommended the alternative project after analyzing 11 options. The price tag more than doubles Oncor's $120.7 million projection.

The project involves converting 69-kV circuits to 138 kV, upgrading more than 65 miles

ERCOT News

of 138-kV lines, removing existing 138-kV circuits from 345-kV structures, and building a new substation.

Error Forces NPRR's Withdrawal

ERCOT staff told the committee it has pulled back an NPRR previously approved by TAC over an error in the protocol language that needs to be resolved before it can go to the board.

NPRR1215 clarifies that the day-ahead market energy-only offer credit exposure calculation zeros out negative values. However, ERCOT's Austin Rosel said an error introduced an unintended change in the E2 credit formula by adding a price variable that wasn't part of the original system design. Comments will be filed to address the error.

"We think this is the best way to get it back to get it corrected," Rosel said.

TAC approved the change in June. It originally was scheduled to go before the board in August but will now have to wait until October.

Changes to CDR's Methodology

Members approved two NPRRs in separate votes. NPRR1219 passed 21-2 with four abstentions; TAC's consumer segment provided both dissenting votes and both abstentions. It proposes changing the methodologies for the capacity, demand and reserves (CDR) report's preparation and incorporates a report release schedule. The NPRR also includes new definitions to support the methodology changes and revisions to address outdated terms and add clarity to the methodology descriptions.

Members raised concerns about using effective load-carrying capability (ELCC) for renewable resources and a rushed process and potential implications of changing the reporting methodology. They warned of confusion over differences in the CDR's reliability metrics and ERCOT's new reliability standard being developed.

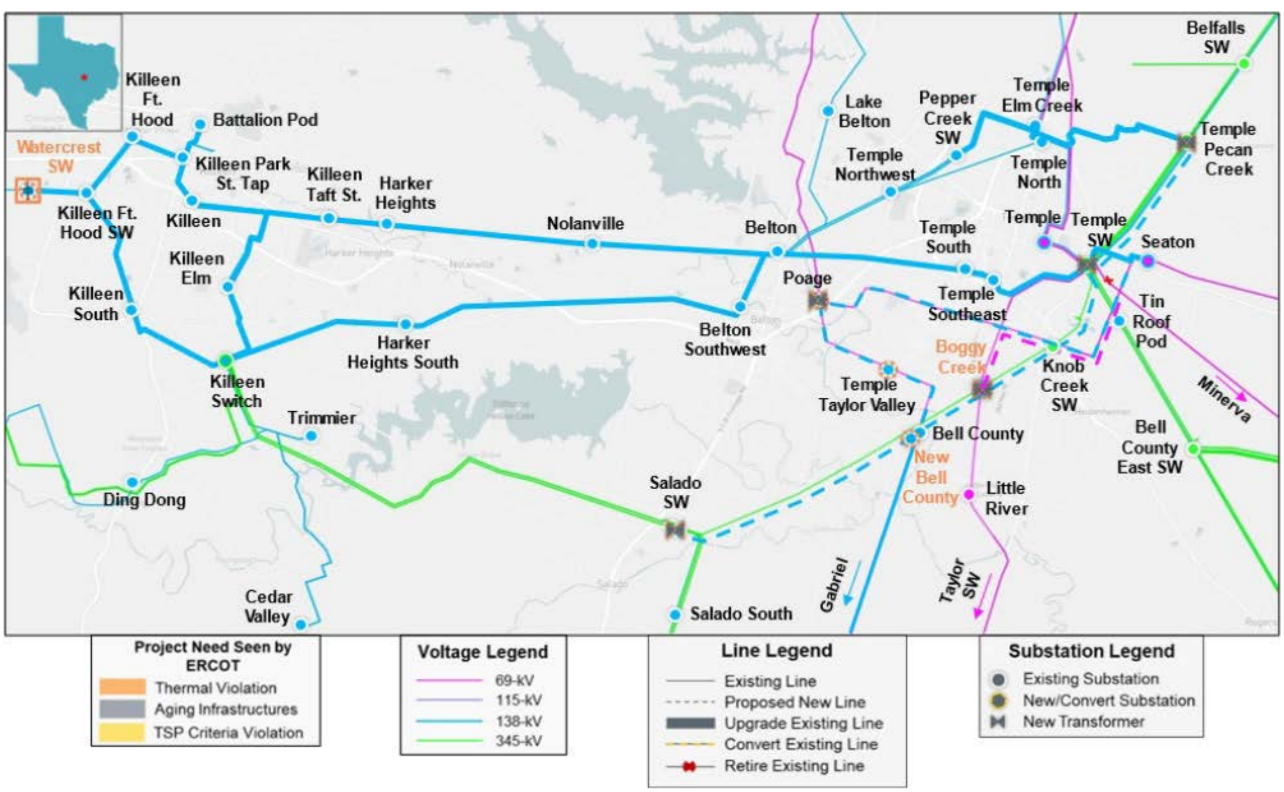
TAC endorsed NPRR1230 23-2, with four abstentions. The four-person cooperative segment cast a dissenting vote and three abstentions over the proposal to establish a shadow price cap for congestion affecting interconnection reliability operating limits.

Members supported the measure because of its market-based approach and operational efficiency. It proposes to manage transmission flows with market mechanisms, rather than manual control room interventions. Cooperatives raised concerns about increased cost to load.

The combo ballot included three other NPRRs, another binding document request and a change to the Verifiable Cost Manual that, if approved by ERCOT's Board of Directors as required, would:

- NPRR1217: Remove the requirement for load resources and emergency response service resources to be deployed with a verbal dispatch instruction (VDI) from ERCOT.
- NPRR1231: Provide more clarifications and improvements to the firm fuel supply service.
- NPRR1233: Add a flat fee for federally owned generation units and adjust the weatherization inspection fee for transmission service providers.
- OBDRR051: Align the methodology for implementing operating reserve demand curve to calculate real-time reserve price adder with system changes required for the emergency pricing program.
- VCMRR040: Remove the need for ERCOT to buy an annual coal price index subscription for use in calculating the quarterly coal fuel adder. The VCMRR describes a methodology for a qualified scheduling entity to submit "actual coal fuel adders" similar to the current process for natural gas resources. ■

— Tom Kleckner



The proposed Oncor project in Central Texas. | *ERCOT*

NEPOOL Participants Committee Briefs

Despite above-average temperatures, the ISO-NE energy market value was *down slightly* in July 2024 relative to July 2023, ISO-NE COO Vamsi Chadalavada said at the NEPOOL Participants Committee (PC) meeting Aug. 1.

| © RTO Insider LLC

Driven by the elevated temperatures, ISO-NE hit its highest peak load of the year July 16 at 24,816 MW, he added.

Chadalavada also provided more information on the capacity scarcity event on the evening of June 18, which lasted about 25 minutes.

The scarcity conditions were caused by about 1,600 MW of generator outages and reductions and a 600-MW generator tripping offline, Chadalavada said. The capacity performance payment rate was $5,455/MWh, and ISO-NE collected $14 million in pay-for-performance charges from underperforming resources.

Votes

The PC *voted* to approve new data collection requirements for distributed energy resources. The new standards would include information on DER size, location and operating characteristics. Data is currently collected through voluntary submissions. (See *NEPOOL Reliability Committee Briefs: July 16, 2024*.)

The committee also supported updates to the financial assurance policy to account for the delay of the 19th forward capacity auction. ■

— Jon Lamson

ISO-NE News

New England States Raise Alarm on Eversource Asset Condition Project

By Jon Lamson

The New England States Committee on Electricity (NESCOE) is raising the alarm on Eversource Energy's planned rebuild of the X-178 transmission line in New Hampshire, arguing the company has not adequately justified the need for the full $385 million project.

Eversource initially presented the replacement project for the 115-kV line to the ISO-NE Planning Advisory Committee (PAC) in *February*. It provided a follow-up presentation to the PAC in June, concluding that a full line rebuild would be more cost-effective than a partial rebuild in the long term. (See *ISO-NE PAC Briefs: June 20, 2024*.)

"Based on the information that Eversource has shared to date, NESCOE is not persuaded that this investment is a reasonable use of consumer dollars," NESCOE wrote in a *memo* published Aug. 1, adding the company has not sufficiently responded to NESCOE's requests for information on the project.

"Absent information showing that this use of consumer dollars is well-supported and reasonable, NESCOE is prepared to use its full resources to explore all available options to dispute the reasonableness of the investments, including but not limited to action at FERC," the committee added.

Escalating costs from asset condition projects, which are intended to upgrade aging and degrading transmission infrastructure, have been a major concern of the New England states over the past year. NESCOE has pushed New England transmission owners for reforms to the asset condition review process at the PAC to provide greater transparency and allow for more stakeholder engagement.

NESCOE noted in a June *memo* that the transmission owners have introduced more than $3 billion in asset condition projects to the PAC since the committee first called for reforms in February 2023.

The $385 million project at issue in the memo is not the largest asset condition project proposed this year; in May, National Grid *presented* a nearly $500 million project. (See *ISO-NE Planning Advisory Committee Briefs: May 15, 2024*.)

Eversource's X-178 project has drawn additional scrutiny in part because Eversource's evaluation of the line identified just 43 of the line's 594 structures as high-priority concerns, and many of the structures are younger than their projected lifespans.

In response to NESCOE's prior calls for asset condition process reforms, the transmission owners have made changes to allow for more stakeholder feedback and have added a new asset condition project forecast *database* and a *process guide*.

NESCOE has called the process updates inadequate and wrote Aug. 1 that Eversource's decision to push forward with the X-178 project despite the objections raised by stakeholders shows more work needs to be done.

"Eversource's persistence in claiming this project is cost-effective without providing the necessary cost details to allow stakeholders to ascertain the reasonableness of this statement underscores the continued need for a comprehensive Asset Condition Needs and Solution Guidance document," NESCOE wrote.

The PAC review process for asset condition projects exists strictly for informational purposes and has no regulatory authority. The prudency review of asset condition projects is under federal jurisdiction, while states have jurisdiction over local land and environmental impacts.

Eversource spokesperson William Hinkle said in a statement the company is reviewing NESCOE's memo, adding that the company is complying with all regulatory requirements for the project and has undertaken "extensive community outreach efforts" beyond what is required for the project.

"Line rebuilds such as this, and asset condition projects more generally, are critical to enhancing reliability for customers as we make the transmission system more resilient to the increasingly extreme weather we're experiencing in New England and addressing aging infrastructure that in many cases was originally built over 50 years ago," Hinkle said.

At an *investor call* Aug. 1, Eversource CEO Joe Nolan said replacing aging transmission infrastructure is a key component of the company's business strategy amid its retreat from the offshore wind business.

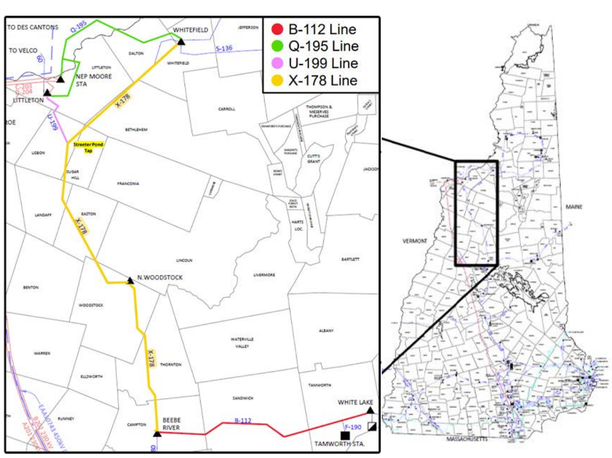
Nolan said the company is focused on "resiliency investments to address aging infrastructure and minimize customer outages," in conjunction with investments to enable load growth and clean energy resources.

He added that the company's five-year plan includes $3 billion in investments to replace aging transmission infrastructure, $1 billion for building and upgrading substations, and $600 million for transmission upgrades to enable new renewable generation.

New Hampshire Consumer Advocate Don Kreis said NESCOE's strongly worded complaint is significant given the committee's typically diplomatic approach, as comments from NESCOE represent the collective views of all six New England governors.

Kreis said it's important that the memo "really isn't just talking about the X-178 line," but instead is aimed at the broader lack of oversight on asset condition projects.

While states cannot review the prudence of the investment, Kreis expressed his hope that the New Hampshire Site Evaluation Committee will take up a review of the project. He said a potential state review process "could be a test of [FERC Commissioner Mark Christie's] hypothesis that the states can and should play a key role in determining whether projects like this go forward." ■



Map of Eversource's X-178 transmission line | *Eversource*

ISO-NE News

ISO-NE Capacity Accreditation Reforms Spur Energy Storage Concerns

By Jon Lamson

As ISO-NE undertakes major capacity market accreditation reforms, New England storage developers are voicing concerns that potential flaws in the RTO's modeling methodology could discourage new investments in storage resources.

The resource capacity accreditation (RCA) project has been in motion for more than two years, and the development process could continue *into 2027* following the RTO's three-year delay of its 19th capacity auction, which applies to the 2028/29 capacity commitment period. (See *NEPOOL Markets Committee Restarts Work on Capacity Market Changes*.)

The RCA project is intended to better align the capacity procurements with real-world reliability benefits, mirroring similar reform efforts in MISO, NYISO and PJM.

Prior to FERC's approval of the full three-year delay — which will give ISO-NE time to reform the timing of the capacity auction process along with accreditation — the RTO published RCA impact analysis *results* that painted a dire picture for storage resources. (See *FERC Approves Additional Delay of ISO-NE FCA 19*.)

While the analysis indicated that the accreditation changes would increase the overall pool of capacity revenue by 11%, it showed a 37% revenue reduction for storage resources, equivalent to about $58 million. (See *ISO-NE: RCA Changes to Increase Capacity Market Revenues by 11%*.)

While these results are subject to change as ISO-NE refines the methodology and accounts for the transition from a forward annual capacity market to a prompt-seasonal capacity market, the analysis served as a wakeup call for many of storage companies participating in the capacity market. (See *ISO-NE Moving Forward with Prompt, Seasonal Capacity Market Design*.)

The concerns about storage accreditation derating come as several New England states are looking to rapidly ramp up the deployment of storage resources; Connecticut, Massachusetts, Maine and Rhode Island all have storage targets in the hundreds of megawatts.

State programs also are a key revenue component for storage developers, as the current levels of revenue from ISO-NE wholesale markets alone are not enough to support the resources, said Alex Chaplin of New Leaf Energy, adding that "storage provides significant reliability benefits to New England which need to be adequately measured and compensated for in the ISO-NE markets."

Chaplin noted that most storage in the region is concentrated in Connecticut and Massachusetts due to their state incentives for storage. Massachusetts' *clean peak energy standard,* which is aimed at cutting emissions and air pollution from fossil peaker plants, is a key revenue source for storage resources in the state. (See *Panel Provides Update on Energy Storage in Mass*.) Decreasing capacity revenue could lead to more pressure on states to support the resources to hit their storage deployment goals and cut emissions.

"Capacity market revenues are typically an irreplaceable and indispensable source of revenue for the financeability and viability of resources, and storage is no exception," said Alex Lawton of Advanced Energy United. He added that the energy market and ancillary services market do not provide "the scale or certainty needed for investors to back storage projects."

The crux of the issue, Lawton said, appears to stem from how ISO-NE is artificially scaling up load in its model to evaluate the reliability benefits of different resource types, which ultimately will determine how much capacity each resource can sell into the market. This modeling shows capacity scarcity events that significantly exceed the duration of events historically experienced in the region.

While the *longest capacity scarcity condition* New England has experienced since the implementation of pay-for-performance rules in 2018 lasted two hours and 40 minutes, the RCA project is modeling events that typically exceed four hours, and — according to a March *presentation* — 36% of modeled shortfall events lasted more than eight hours.

"As soon as you exceed four hours in duration — because most storage is between two and four hours — the marginal reliability impact (MRI) of storage just tanks," Lawton said.

There is broad consensus that the region's power grid will face longer-duration periods of shortfall risk in the future as it trends toward a winter peaking system, but there is uncertainty around when these longer-duration risks will show up, and how they should be weighed against higher-likelihood, shorter-duration events.

Over the long term, ISO-NE has stressed the need for dispatchable resources that can balance intermittent generation over extended periods of time. (See *ISO-NE Outlines Economic Challenges of Decarbonization*.)

Frank Swigonski of Jupiter Power said the weighting of extreme winter storms in the methodology compared to more frequent, shorter-duration events "is an open question … that stakeholders should explicitly discuss in this process."

Swigonski noted the stakeholder engagement process for PJM's accreditation reforms did not spend significant time discussing this question, which led to rehearing requests with FERC.

"It ultimately had a massive impact on the final accreditation numbers," Swigonski said. "We're hoping that we don't have the same experience in New England."

Swigonski also disagreed with the notion that shorter-duration storage resources are unable to provide significant resource adequacy benefits during longer-duration events. Storage resources likely still will be able to recharge off-peak during extended events, and operators eventually will gain experience with dispatching storage to avoid depleting all available storage in the first hours of an event, he said.

Responding to questions about the RCA methodology, ISO-NE spokesperson Mary Cate Colapietro emphasized that the methodology is still a work in progress and that stakeholder engagement is ongoing. ISO-NE recently solicited comments on the scope of its Capacity Auction Reform (CAR) project, which included requests from storage companies for ISO-NE to evaluate the underlying modeling methodology.

"Establishing a durable capacity market that provides the necessary reliability services as the power system evolves is a vital component of New England's clean energy transition," Colapietro said. "While we plan to continue pursuing an accreditation design based on capacity's marginal reliability impact, the additional time afforded by the delay gives us time to work with stakeholders on possible improvements to that design."

Bruce Anderson of the New England Power Generators Association declined to comment on the treatment of specific resource types but stressed the need for ISO-NE to prioritize implementing a "sound market design" that provides efficient signals for resources to enter and exit the market. ■

MISO News

Research Firm Emphasizes MISO Queue's Wait Times, Bigger Projects, Tx Influence

By Amanda Durish Cook


| Alliant Energy

A recent webinar from U.K.-based analytics firm Aurora Energy Research drew attention to promising and troubling trends alike in MISO's interconnection queue process, including longer wait times, larger projects, solar's significance and major transmission's influence.

Joe Rand, energy policy researcher for Lawrence Berkeley National Laboratory, said the progression from MISO interconnection request to agreement in 2023 has lengthened to about 45 months, with natural gas projects moving the fastest and wind projects moving the slowest.

"The queue duration has become longer and longer," Aurora researcher Annie Liu agreed during the July 31 presentation. She said while MISO's approximately 300-GW queue has grown rapidly in the past two years, 40% of active projects in the queue have not begun interconnection studies.

While the wait times have increased, so too have the size of projects.

Rand said increasingly bigger solar and storage projects have entered MISO's queue over the past decade, with the mean capacity of a solar plant entering the queue in 2022 now at 186 MW, up from about 100 MW in 2016. Rand also said the mean size of storage facilities has risen almost 500% in the past 10 years to about 200 MW apiece.

Rand said as of late 2023, 20% of proposed solar projects in MISO's queue and 6% of proposed wind farms are planned as hybrid configurations with storage on site.

But Rand said the number of projects and capacity withdrawing from MISO's interconnection queue is on the rise, as it is with other grid operators.

Aurora acknowledged the stronghold solar holds on the MISO queue.

Solar represents most of MISO's interconnecting capacity, at 166 GW; over the past three queue cycles, solar has accounted for 47% of projects, Aurora found.

Liu said that many of the solar and battery projects that entered the 2023 cycle are concentrated in the MISO Central region, which includes Michigan, Wisconsin, Illinois, Indiana and portions of Missouri and Kentucky. Liu said 21 GW of battery storage and 22 GW of solar projects from the 2023 class are vying for locations in MISO Central. But she said MISO South also is attractive to solar developers, with 24 GW of project potential entering 2023 cycle alone.

"There's a strong developer interest in MISO South, especially in Arkansas and Louisiana," Liu said.

Interest in storage is shooting up too, researchers said.

Aurora researcher William Eastwick noted that more than 60 GW of standalone battery storage projects have entered the queue in the past three cycles. They tend to select locations near solar hot spots, hoping to leverage a "technologic synergy" between solar and storage, he said.

Eastwick also predicted MISO's long-range transmission plan (LRTP) portfolios will shape future developer behavior, with many opting to site projects near future lines.

He said while developers have "cooled off" on siting wind projects in Iowa — which now is notorious for curtailments and some of the lowest prices in MISO — MISO's second, $25 billion LRTP portfolio has the potential to beckon developers again to Iowa, where new LRTP projects can transport wind generation to eastern load centers in Wisconsin and Illinois.

Aurora Energy Research MISO market lead Jose Munoz said developers should be able to make more informed siting decisions for their generation projects after MISO's Board of Directors votes to approve the second LRTP portfolio at the end of the year. He added the 2023 class of potential capacity has a "strong correlation" with MISO's first LRTP portfolio.

However, Eastwick said MISO's recent stepped-up rules requiring more capital upfront and more financial risk have the "potential to affect cashflows" of MISO's developers.

MISO last year doubled developers' first milestone fee from $4,000/MW to $8,000/MW and instituted automatic monetary withdrawal penalties. The RTO still is attempting to find a plan that FERC can agree with to cap the number of megawatts it will accept annually into the queue. (See *MISO Sets Sights on 50% Peak MW Cap in Annual Interconnection Queue Cycles*.)

Munoz said MISO's higher-stakes financial environment hasn't deterred developers so far.

"Despite passing a suite of reforms making the interconnection queue process more restrictive, MISO saw the second-largest queue cycle size to date, with 115 GW of capacity submitting applications to interconnect," Munoz said. ■

MISO News

Environmental Groups Seek Rehearing of MISO Sloped Demand Curve

By Amanda Durish Cook

MISO's offices in Eagan, Minn. | *© RTO Insider LLC*

The Sierra Club, Natural Resources Defense Council and the Sustainable FERC Project are seeking a rehearing of MISO's sloped demand curve in its capacity auction, arguing that it's unreasonable for the RTO to require utilities to procure capacity beyond resource adequacy needs.

FERC last month allowed MISO to replace the vertical demand curve it had been using since 2011 with downward-sloping demand curves. (See *FERC Approves Sloped Demand Curve in MISO Capacity Market*.)

The trio claimed in a July 29 filing that FERC's June acceptance violates the Federal Power Act and Administrative Procedure Act by requiring load-serving entities that opt out of MISO's voluntary capacity auction to buy more capacity than what MISO deems acceptable (*ER23-2977*).

When it installs a sloped demand curve for the 2025/26 Planning Resource Auction, MISO will impose an "x% adder" on load-serving entities that decide not to participate in the capacity auction. The adder will require load-serving entities to secure more capacity than necessary to meet MISO's planning reserve margins, which are derived from a one-day-in-10-years system reliability standard. The adder will be based on how much excess capacity is procured through the auction in previous years using the sloped demand curves.

The Sierra Club, NRDC and the Sustainable FERC Project said use of the adder would impose "significant artificial costs" on ratepayers and distort market signals.

"It is both arbitrary and improper to impose the excess reserve margins created by a market construct whose principal purpose is to vary reserve margins in order to mitigate extreme price fluctuations and better guide resource investment decisions back on entities who are not participating in that market," the three argued.

They said forcing load-serving entities to procure extra capacity undermines MISO's "carefully measured" resource adequacy standard.

They also said MISO put too much emphasis on using the adder to prevent non-participating load-serving entities from benefiting unfairly from potential excess capacity from other LSEs participating in the auction. Equally as important, the three argued, is the possibility that LSEs using the PRA benefit from opted-out LSEs' obligation to meet their individual reserve margins in the years when the PRA clears below its reserve margins.

"The adder is not about ensuring comparability but instead functions as a one-way ratchet to require excess procurement of capacity by utilities that opt out of the PRA," they told FERC. ■

WEC Energy Group Concentrates on Natural Gas, Solar to Meet Data Center Growth

By Amanda Durish Cook

WEC Energy Group's second-quarter earnings call zeroed in on the new natural gas and solar generation the company plans to bolster Wisconsin's economic resurgence.

WEC Energy Group CEO Scott Lauber said a surge in economic activity in Wisconsin underscores the need for the company's largest-ever, $24 billion, five-year capital plan.

He said the plan as it stands today focuses on "low-risk and highly executable" projects heavy on natural gas and solar generation.

Lauber said at the end of May, WEC Energy Group closed on its second option at Alliant Energy's 730-MW West Riverside Energy Center, which has the company trading $100 million for 100 MW of combined cycle natural gas generation.

He also reminded shareholders the company will spend a total of $2.1 billion on 1.2 GW in natural gas generation at its existing Paris and Oak Creek power plant sites. That amount includes a 2-billion-cubic-foot LNG storage facility and a 33-mile gas line to serve the Oak Creek site, which is planned to be converted from coal to gas over multiple years with construction of a combustion turbine plant.

Lauber said the company continues to make meaningful progress on reducing greenhouse gas emissions. He pointed out that in May, the company shuttered coal Units 5 and 6 at the Oak Creek plant, representing more than 500 MW.

"Including these units, since 2018, we have retired nearly 2,500 MW of older, fossil fuel generation," Lauber said.

Lauber said the company hopes for a decision from the Wisconsin Public Service Commission before the end of the year to spend $580 million to purchase a 90% ownership interest in Invenergy's 300-MW High Noon Solar Energy Center in southern Wisconsin. High Noon features 300 MW of solar generation and 165 MW of battery storage and is planned to begin operating in 2026.

He said WEC Energy Group's infrastructure segment expects two more solar farms it will have majority stakes in to come online by the end of the year. Invenergy's 300-MW Delilah I solar project northeast of Dallas was delayed from its original operational date in June by damage from a hailstorm in northeast Texas. WEC plans to spend about $460 million for a 90% ownership interest in the farm. WEC also will invest $360 million for an 80% ownership interest in Invenergy's 250-MW Maple Flats solar farm in Illinois.

WEC Energy's Oak Creek plant undergoing expansion in the mid-2000s | *Bechtel*

Meanwhile, Lauber said Microsoft is making "good progress" on its data center campus in southeast Wisconsin.

Microsoft announced in spring that southeast Wisconsin will be the site of a $3.3 billion *investment* in cloud computing and AI infrastructure through the end of 2026.

Lauber said the company is formulating a refreshed five-year capital plan that he plans to share in the fall that accounts for more data center development.

"We are currently working with Microsoft and developing our plans for our next five-year plan," Lauber said.

He said WEC Energy Group so far has contemplated only the energy needs of Microsoft's first 315-acre purchase on the southeast Wisconsin site. Microsoft last fall purchased an additional 1,030 acres, and last week bought a further 173 acres in the area.

"We've been working with Microsoft on the needs for the area. Wisconsin's got a lot of development opportunities, and we want to make sure we hit the capacity requirements we need for the area to support the growth — not just Microsoft, but all the other growth we're seeing in the region," Lauber said.

Lauber pledged more filings to add renewable capacity soon. He also said the company is focused on Transmission Co.'s transmission expansion plans in Wisconsin, as well as its own growing distribution needs.

"We're factoring all that in as we pull together our five-year plan," he said.

Lauber also said the company hopes for a decision from the Wisconsin PSC by the end of the year on a requested $800 million in electric and gas rate hikes for We Energies and Wisconsin Public Service customers. If approved, a residential customer's bill would rise by $10 to $11 over 2025 and 2026. Citizens Utility Board has *said* the proposed increase would drive energy costs too high.

During the quarter, WEC Energy Group *reported* net income of $211.3 million ($0.67/share), down from $289.7 million ($0.92/share) in the second quarter last year, a 25-cent/share decrease year over year. Revenues were bruised by a warm end of winter, storms and higher operating costs and interest rates. ■

MISO News

MISO in June: Unchanged Pricing, Lower Peak than Expected

By Amanda Durish Cook

June brought MISO a peak 2 GW lower than anticipated and unchanged real-time and fuel prices from last year, the RTO said in its monthly operations report.

MISO encountered a 113-GW peak on June 24 as a sustained heat wave sent temperatures into the high 90s across the Central and South portions of the footprint. However, the month's *peak* was lower than MISO's 115-GW probable demand *forecast* for June that it published in the days leading up to the season.

The peak demand for June this year was higher than last year's 111-GW apex but well below 2022's 121 GW. Load averaged 82 GW, slightly higher than last June's 81-GW average.

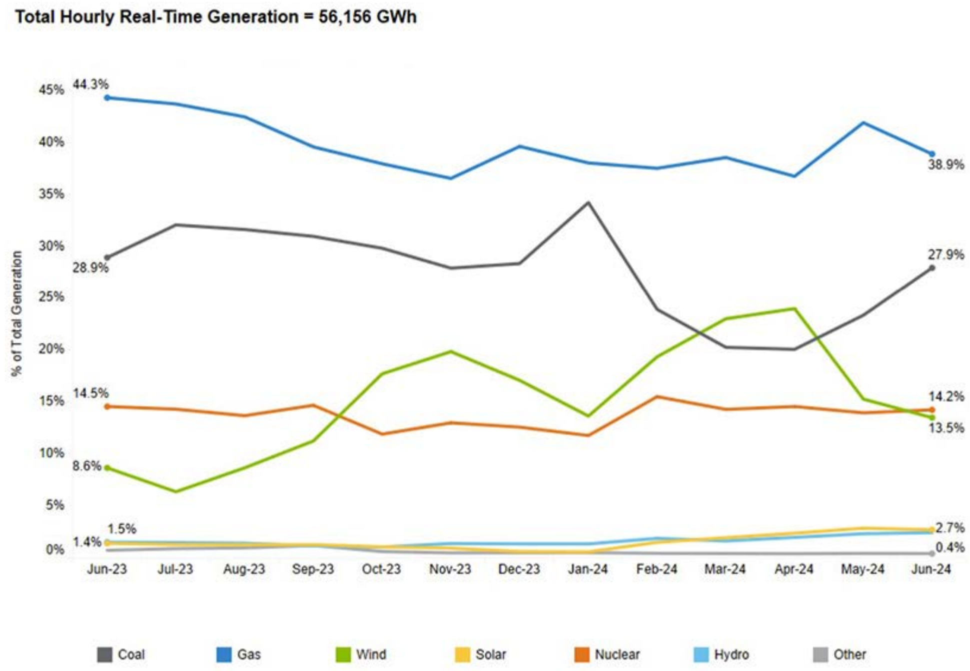
The RTO's average natural gas and coal prices did not budge from last June, staying about $2/MMBtu. Similarly, real-time LMPs reflected no change year over year, hovering at $28/MWh.

MISO matched a 6.2-GW all-time solar peak it set in May on June 14, when the collective panels of the footprint managed about 12% of load for a brief period.

The RTO's approximately 56 TWh of production for the month were supplied 39% by natural gas generation, 28% by coal generation, and about 14% apiece by wind and nuclear generation. Hydro and solar power each contributed almost 3%.

Daily generation outages stood at an average of 35 GW, lower than 2022 and 2021's 40 GW and 2023's 38 GW.

MISO ultimately issued conservative operations instructions for its North region on June 25 and for its North and Central regions on June 28 because of above-normal temperatures.



MISO's hourly real-time generation mix from June 2023 to June 2024 | *MISO*

However, MISO has yet to issue emergency instructions this summer, including this month. Though MISO issued a capacity advisory for its North and Central regions and conservative operations for the entire footprint on July 15, the combination of forced generation outages, hot weather and transfer capability issues did not rise to an emergency level.

Currently, MISO is *navigating* a capacity advisory for its Central and North regions and conservative operations for the entire footprint through July 31 because of heat, forced generation outages and higher-than-forecasted load.

On July 30, MISO relied heavily on its coal (41 GW) and gas (44 GW) resources to meet a 115-GW peak. Prices ranged from $39 to $49/MWh. ■

PJM News

PJM Capacity Prices Spike 10-fold in 2025/26 Auction

Load Growth, Deactivations, Risk Modeling Changes Cited as Causes

By Devin Leith-Yessian

PJM capacity prices increased nearly tenfold in the 2025/26 Base Residual Auction (BRA) as a trifecta of load growth, generation deactivations and changes to risk modeling shrank reserve margins.

The clearing price for most of the RTO jumped to $269.92/MW-day, far above the $28.92/MW-day for the 2024/25 auction. Two regions surged to their price caps, reaching $466.35/MW-day in the Baltimore Gas and Electric (BGE) zone and $444.26/MW-day in the Dominion zone. (See *PJM Capacity Prices Jump in 5 Regions.*)

"The significantly higher prices in this auction confirm our concerns that the supply/demand balance is tightening across the RTO. The market is sending a price signal that should incent investment in resources," PJM CEO Manu Asthana said in a July 30 *announcement* of the BRA results.

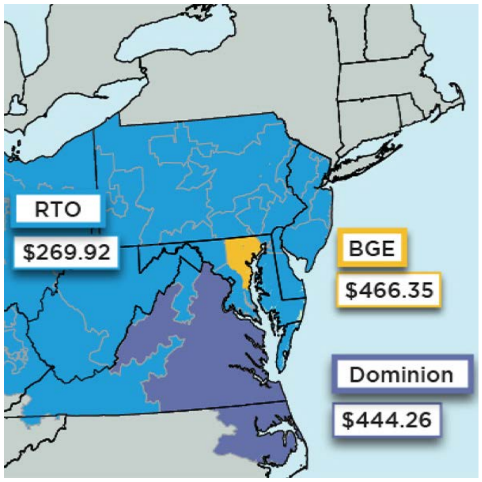
PJM forecasts a peak load of 153,883 MW for the 2025/26 delivery year, up 3,243 MW from the previous year. The auction procured 135,684 MW of capacity at a record $14.7 billion to serve that load, with an additional 10,886 MW supplied through fixed resource requirement (FRR) plans.

The total installed capacity was around 182 GW, resulting in an 18.5% reserve margin, just over the 17.8% installed reserve margin (IRM) target. The Dominion and BGE zones landed just under their reserve requirement and are transmission-constrained, causing prices to jump to the zonal cap.

PJM Executive Vice President of Market Services and Strategy Stu Bresler said the auction procured adequate supply and sent a signal that investments in capacity are needed for future delivery years. He cautioned that capacity costs remain just one component of consumers' bills and the results should not be read as causing a multifold increase in retail rates.

"Auction prices were significantly higher in this auction and those steep increases, we believe, do signal the need for investments," he said during a press conference July 30.

The auction followed a yearslong trend of declining supply, with around 6.6 GW retiring or being approved for a must-offer exemption, which signals their intent to deactivate. Bresler



PJM capacity prices increased nearly tenfold in the 2025/26 Base Residual Auction, with two regions reaching their zonal caps. | *PJM*

said the tension between supply and demand demonstrates the reliability concerns the RTO highlighted in a February 2023 Energy Transition in PJM *white paper*. (See "PJM White Paper Expounds Reliability Concerns," *PJM Board Initiates Fast-track Process to Address Reliability.*)

Bresler said PJM is searching for solutions to speed the generation interconnection process to facilitate new resource development; however, 38 GW of resources have cleared the generation interconnection process but have yet to enter commercial operation.

"Interconnection process reform is proceeding, but hurdles remain for many projects outside of our process," Bresler said in the announcement accompanying the auction results. "We are considering ways to accelerate those who can successfully overcome those challenges and build."

In addition to tighter supply and demand, Bresler said the cost increase was driven by a shift in how PJM models reliability risks and matches them with resources accreditation (*ER24-99*). (See *FERC Approves 1st PJM Proposal out of CIFP.*)

The changes use PJM's marginal effective load-carrying capability (ELCC) framework to accredit all resources, except energy efficiency, and rely on its hourly probabilistic modeling to calculate capacity needs through the reserve requirement study. The new approach concentrated reliability risk into the winter and led to several resource classes seeing reduced accreditation. (See "Revised Reserve Requirement Study Values Endorsed," *PJM MRC/MC Briefs: March 20, 2024.*)

Auction Conducted After Several Delays

The timing of the auction has been repeatedly delayed from the original May 2022 schedule to implement several market changes, including reversing an order establishing a forward-looking energy and ancillary services (EAS) offset, followed by the CIFP changes. (See *FERC Approves PJM Capacity Auction Date Changes.*)

An additional delay approved in February pushed the opening of the auction from June 12 to July 17 to grant market participants additional time to understand how the RTO will calculate effective load-carrying capability (ELCC) ratings to accredit the capacity resources can provide. (See *FERC Approves PJM Capacity Auction Delay.*)

EPSA Says Increased Prices Reflect Increased Risks, Manufacturers Skeptical

Electric Power Supply Association (EPSA) CEO Todd Snitchler said the increased capacity prices are an encouraging first step in meeting the mounting reliability risks PJM has identified.

"While there is still work to be done, these price signals recognize the situation PJM faces and should begin to incentivize the investment needed to deliver a reliable system in PJM and in other U.S. markets," Snitchler said in a statement. "Reliability watchdogs, regulators, policymakers and PJM itself have been sounding the alarm that the misalignment of power resource retirements and additions poses a serious reliability risk to the grid — especially in the face of rising demand spurred by data center and manufacturing growth among other factors like electrification, extreme weather and policy choices."

Ryan Augsburger, president of the Ohio Manufacturers' Association, said in a statement that auction delays will translate to higher capacity costs for consumers.

"Markets work — but after years of delay of PJM's critical capacity auction, prices are rising to attract generation in a hurry. PJM's capacity auction will yield billions more for generators that locate in its territory to serve healthy customer electric load, but customers will bear the brunt of PJM's costly auction delays," he said. ■

PJM Market Participants React to Spike in Capacity Prices

By Devin Leith-Yessian

Manu Asthana, PJM CEO | *© RTO Insider LLC*

Generation owners point to the nearly 10-fold increase in capacity prices seen in the 2025/26 Base Residual Auction (BRA) results announced July 30 as the price signal they need to invest in new development. Meanwhile, consumer advocates say they worry a compressed auction schedule and backlogged interconnection queue will limit the ability for market participants to react.

The clearing price for most of the RTO jumped to $269.92/MW-day and two regions surged to their price caps, reaching $466.35/MW-day in the Baltimore Gas and Electric (BGE) zone and $444.26/MW-day in the Dominion zone. The "rest-of-RTO" price in the previous auction was $28.92/MW-day. (See related story, *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

PJM said the increase was driven by tightening supply as generation resources retire, increased demand as data center load is expected to come online and a shift in how PJM forecasts reliability risks and determines the capacity contribution for resources.

Nearly half of the capacity that cleared the auction was supplied by gas generation, at 48%, followed by 21% nuclear and 18% coal. Demand response made up 5% of cleared capacity. Hydro fell to 4% and wind and solar were at 1%.

"The significantly higher prices in this auction confirm our concerns that the supply/demand balance is tightening across the RTO. The market is sending a price signal that should incent investment in resources," PJM CEO Manu Asthana said in a July 30 *announcement* of the BRA results.

Consumer Advocates, Enviros: Sluggish Planning and Market Design

Illinois Citizens Utility Board Executive Director Sarah Moskowitz said PJM has been slow to adapt and failed to design a capacity market that sparks new generation investments without creating a windfall for developers.

"The power grid operator's compressed auction schedules mean generators can't build and come online quickly enough to respond to prices and bring down costs. Just as concerning, PJM has dragged its feet on interconnection and long-term transmission policy reforms that could speed up its approval process and bring needed clean, affordable energy online more quickly. Similarly, we have concerns about the accuracy of PJM's load forecasting, as detailed in a recent *letter* from consumer advocates to PJM," she said.

Susan Bruce, representing the PJM Industrial Customers Coalition (ICC), said the auction results differ significantly from simulated results PJM presented in the stakeholder process and it remains unclear what led to that gap.

"Regardless, the auction results will have a serious impact on customers. Given the timing of the auction relative to the 2025/2026 delivery year, customers have little to no opportunity to take action to minimize the cost consequences. And with delays in the interconnection queue, there is real concern about what may happen in the next auction," she said. "Focused and dedicated efforts must be undertaken — post haste — to ensure that PJM market design can both facilitate new entry and retention of resources, without market power being exercised, better accommodate single point load integration, and properly reflect the value of non-weather sensitive customers' demand response capability."

Tom Rutigliano, of the Natural Resources Defense Council, said the price jump is the result of a reliance on fossil fuel generation at the expense of designing a market and grid set up to facilitate the development of clean energy. Gas-fired resources in particular, he said, have failed to live up to the promise of delivering reliability at low cost.

"Make no mistake: This was foreseeable and preventable. This is what happens when regulators sideline a wealth of historically affordable clean energy resources waiting at their doorstep and the transmission needed to bring them online. For years, the largest grid operator in the eastern U.S. has all but refused to diversify its resource mix and bring new energy online, and instead opted to depend excessively on an aging fossil fuel fleet while ignoring its reliability failures. This sticker shock is a direct result of recent regulatory changes made to address those reliability failures."

He argued the cure to high capacity costs lies in the renewable energy projects pending in PJM's interconnection queue.

"Diverse power grids are critical for reliability, and now we see just how critical they are for affordability. With wind and solar only making up an abysmal 2% of resources in this auction, but the overwhelming majority of PJM's project queue, it is clearer than ever that PJM needs to rapidly scale up new energy resources to protect customers and resilience," he said. "The cost of PJM's interconnection delays has now reached billions of dollars. Leaders in PJM states must demand accountability and solutions from their grid operator before they have to pay billions more in the next auction just five months from now."

PJM spokesperson Dan Lockwood said the RTO is in the process of implementing a FERC-approved reworking in how it conducts generation interconnection studies, which uses a cluster-based approach to determining any necessary network upgrades and allocat-

PJM News

ing costs. He said that approach is expected to process 72 GW of resources in 2024 and 2025.

"Today, about 38,000 MW of resources that have already cleared PJM's interconnection process have not been built due to external challenges that have nothing to do with PJM, including financing, supply chain and siting/permitting issues. PJM remains concerned with this slow pace of new generation construction and is considering ways to accelerate those who can successfully overcome those challenges and build," Lockwood said.

Transmission Owners See Regulated Generation as Solution

During the utility's July 31 earnings call, FirstEnergy CEO Brian Tierney said the high capacity prices and sluggish resource development suggest state administered capacity procurements may have a part to play in augmenting PJM's marketplace, pointing to those run by the New York State Energy Research and Development Authority (NYSERDA) and New York Power Authority (NYPA).

The utility has limited ability to own capacity assets in many states. However, conversations about permitting it to develop dispatchable generation with a regulated return could allow it to respond to price signals when other market participants are not. In states where FirstEnergy does own generation, like West Virginia, he said that could take the shape of new combined cycle gas resources, while in Pennsylvania, that would take legislative changes.

"There are people that get upset and say, 'You're going back to regulation.' I don't think you have to go back to regulation. I think you can still have energy markets. I think you can still have retail choice where you have it today. But I also think you could have constructs like NYSERDA or NYPA where they could buy on behalf of the state's residents. And that doesn't have to be an end to competition," Tierney said. "And they can even have auctions where all people could participate in that: utilities, independent power producers and others. So, for the people that say it has to be one or the other, I just don't think that's a valid premise."

Part of the difficulty Tierney outlined is the disparity between the amount of time it takes to plan and develop new generation resources, compared to how quickly new loads can come onto the grid. He said new resources built in response to the higher prices could take as long as six years to come online, falling toward the end of the period PJM said it's concerned about resource adequacy in a February 2023 *white paper*. (See "PJM White Paper Expounds Reliability Concerns," *PJM Board Initiates Fast-track Process to Address Reliability*.)

While he said new resources with a regulated return could be part of the solution, Tierney said developing new competitive generation is off the table.

"The thing we wouldn't be willing to do would be start competitive generation of our own. That's something that we've recently come out of. We paid a heavy price for that. We've rebuilt our balance sheet in the wake of that, and that's not a place that we're going to be going back to. But other things, other opportunities that could benefit our customers have the capacity that they need be responsive from a price standpoint are all things that are on the table and are all things we're talking to our states about," he said.

In a statement, Exelon said the results show a need for new generation and transmission assets, particularly within the constrained BGE zone. In its announcement of the auction results, PJM said the higher zonal prices for BGE and Dominion were the result of insufficient generation within the zones and limited transmission to import from other regions.

"The recent PJM auction results underscore a critical need for strategic investments within the Exelon footprint, particularly in our BGE service territory in Maryland. The elevated price levels in this area, as well as others, reflect both a scarcity of resources and transmission constraints. Even with Exelon's ongoing investments, including $34.5 billion over the next few years to upgrade the energy grid, additional transmission projects are still needed to ensure the strength and reliability of the energy grid now and in the foreseeable future," the utility said.

During Exelon's Aug. 1 earnings call, CEO Calvin Butler said all options are being pursued in response to a question asking whether the utility is looking at authorization for including peaker generation in rates.

"We're working with our commissions on all types of scenarios. We shouldn't take anything off the table because we need to address this issue and ensure affordability and equity [are] at the forefront of all discussions," he said.

Generators Say Auction Delivers Needed Investment Signal

Enel North America Head of Energy and Commodity Management Roberto Rosner said the auction tells generation developers that now is the time to build new capacity resources.

"The signal from the auction is unmistakable: PJM needs more clean generation and more flexible demand-side resources. Power producers like Enel are eager for PJM to implement its interconnection reform so we can add more clean, affordable megawatts to the grid. As load forecasts rise from electrification and data center buildout, the value of demand response for maintaining reliability has never been clearer. It's also clear that the substantial derate of capacity through ELCC ratings had a meaningful impact on the outcome."

Voltus President Matthew Plante said the results were predictable given the number of generation retirements and PJM's load forecasts. However, shifts in resource accreditation also had a large impact on the amount of supply able to offer into the auction. PJM's shift to marginal effective load carrying capability (ELCC) and reworked risk modeling led to the focus on when resources can perform shifting from summer to winter.

"As the grid changes, we're no longer in a situation where peaks are always during the summer months. In fact, the last time PJM dispatched the emergency load reduction program was December 2022 ... so now it's more likely that PJM will need these resources in the winter than in the summer," he said.

For demand response, that led to a 25% derate in the capacity resources could offer, reducing DR supply by about 3,000 MW. Nonetheless, Plante said the high price point is likely to turn around a yearslong decline in DR participation in PJM's capacity market. Asset-backed DR resources — such as smart thermostats, batteries or anything requiring a capital investment — are especially likely to be buoyed by the high prices.

"It's hard to find a customer that doesn't want to take advantage of the value proposition that now exists," he said.

Technological barriers have limited DR participation in the past, but most of those have been alleviated in recent years, Plante said. PJM and DR providers are working on addressing remaining regulatory barriers. He called the ELCC derate a "sledgehammer solution" and said the whiplash of frequent rule changes could affect market participation.

"I think regulators need to understand that there's sometimes we change the rules too frequently and are reactive to things, and yes, a whiplash on rules in particular leads to volatility in the number of megawatts enrolled," he said. ■

PJM News

Maryland PSC Approves Waiver for Data Center Grid Expansion

Data Center Hub in Frederick Will Connect to Virginia's Data Center Alley

By K Kaufmann

Maryland is setting itself up to compete with Northern Virginia's Data Center Alley with a 2,100-acre data center campus in Frederick County, and on July 31, the Maryland Public Service Commission granted a waiver for Potomac Edison Co. to install two 230-kV lines to help connect four data centers from the campus to a new substation.

The 3-1 vote on the waiver allows Potomac Edison to begin construction on the lines in September without first requesting a certificate of public convenience and necessity (CPCN), a much longer and more expensive process.

Commissioner Bonnie Suchman cast the single no vote, arguing the waiver could open the door for more waiver requests for similar line additions for more data centers, with other customers picking up the bill.

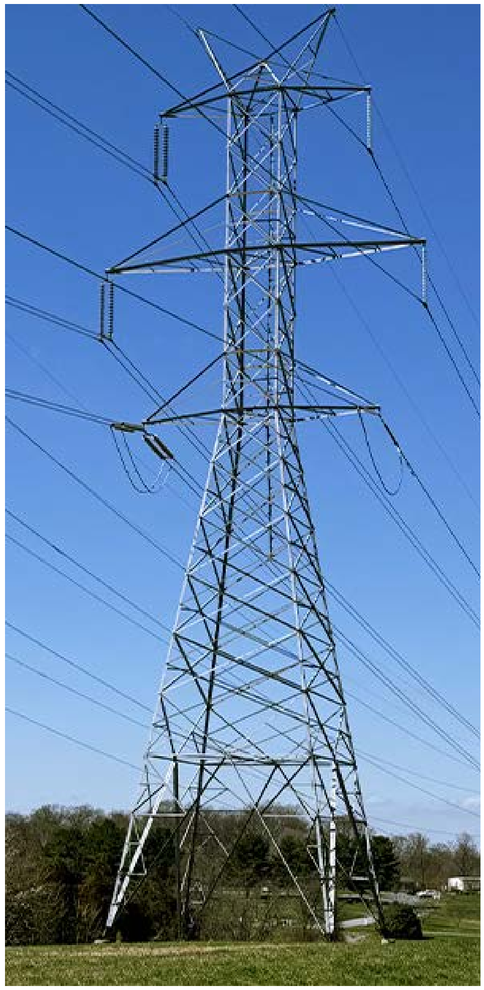
Potomac Edison's customers in Frederick County don't need the upgrades at present, Suchman said. "Upgrades are only coming because of this new data center. … You're going to get more data centers coming in, and more data centers are going to put more burdens on the system, and then you're going to come to us for a waiver, and we're going to sort of rush all this stuff through.

"The data center may come or not, but the one thing I am seeing is an increase in the cost for the network that's going to be borne by the ratepayer," she said.

According to commission staff, however, the project meets specific legal standards in the state's public utilities code that require the PSC to grant the waiver: The new lines won't require the utility to secure new property or rights-of-ways or to install bigger or taller structures for increased voltage or larger conductors.

The Potomac Edison lines will be "loop lines" that run from an existing 230-kV line to a new substation to be built for the data center and then back to the main line. Each line will be 1,100 feet long and use the same type of wires as the existing line, and will include eight new poles, none of which will be taller than existing poles.

The staff report also said the new lines and other system upgrades, including a switching station expansion, will mitigate potential thermal overloads and voltage violations the new data centers could cause on the main line, as identified by PJM.



| © RTO Insider LLC

"PJM did that specifically for reliability reasons … not only to take into consideration [the data center's] anticipated load, but the other load currently being served and to be served in that area, altogether about 1,350 MW," said Joey Tsu-Yi Chen, corporate counsel for Potomac Edison. "We do not want to see a situation, in fact, cannot, where we have no more than 300 MW of load that would be interrupted by any particular criteria."

However, PJM spokesperson Jeff Shields said the RTO neither planned nor approved the two lines. Rather, FirstEnergy, which owns Potomac Edison, included the project in a supplemental filing to the RTO's Transmission Expansion Advisory Committee in October 2023.

Data Center Alley North?

Reliability aside, Chen told the commission the waiver was needed so the new lines could be built to meet the data center's timeline. A full CPCN review would not meet "their timing needs for their project," he said — underlining the disconnect between digital and regulatory time frames, and Suchman's concern Potomac Edison's waiver request could be the first of many.

Maryland has been promoting itself as a nearby, attractive alternative to Northern Virginia, home to hundreds of data centers and skyrocketing power demand. Gov. Wes Moore (D) rolled out the welcome mat in May when he signed the Critical Infrastructure Streamlining Act of 2024 (*S.B. 474*), waiving the need for data centers to get CPCNs for their fossil fuel-powered backup generators.

The Frederick County data centers could provide a glimpse of what's to come. The developer for the project is Rowan Digital Infrastructure, which provides "turnkey data center campus solutions" with "de-risked development timelines," according to the *company website*.

The data centers will cover about 145 acres in the larger, 2,100-acre Quantum Frederick data center campus being planned by developer Quantum Loophole. Rowan's website describes its project as a multi-building facility with 300 MW of power to start and the potential to expand to 450 MW.

The Frederick County site offers "near-term power interconnection dates [and] competitive power pricing … [and can] deliver the initial 300 MW by late 2025, providing a high-value alternative to the congested Ashburn corridor" in Northern Virginia.

Quantum also has big plans for the site, which it intends to connect to its data center hub in Northern Virginia with a 40-mile fiber optic network ring.

"At full capacity, the 34 conduits will hold more than 235,000 strands of fiber to transmit data between the two hubs in under one millisecond Round Trip Time (RTT)," a company press release said. ■

PJM News

DC Circuit Vacates Pipeline Approval FERC Issued over NJ's Objections

By James Downing

The D.C. Circuit Court of Appeals on July 30 vacated and remanded an order by FERC approving a natural gas pipeline in New Jersey that state regulators said was unneeded (*23-1064*).

FERC last year approved Transcontinental Gas Pipe Line Co.'s Regional Energy Access Expansion Project to boost gas delivery by 829,400 dekatherms/day to bring gas from Pennsylvania into New Jersey over the objections of New Jersey regulators and others (CP21-94). (See *FERC Approves Pipeline Expansion Despite New Jersey's Worries*.)

Before the gas project came to FERC for approval, the New Jersey Board of Public Utilities opened a proceeding on the future of natural gas in the state, which determined it did not need additional pipeline capacity through at least 2030. That proceeding was opened in February 2019; Transco applied to FERC in March 2021; the BPU issued a final order in the proceeding in June 2022; and FERC approved the pipeline expansion in January 2023.

About 73.5% of the project's gas was destined for customers who signed contracts in New Jersey, but the rest was for Delaware, Maryland and Pennsylvania.

The New Jersey Conservation Foundation, New Jersey Division of Rate Counsel, New Jersey Attorney General's Office and others challenged FERC's approval after the commission upheld it on rehearing.

The court found that FERC failed to make a significance determination when it came to the project's greenhouse gas emissions and failed to discuss mitigation measures.

FERC quantified the emissions associated with the project, finding construction could add 43,548 metric tons of CO_2 equivalent, while operation would add 562,044 metric tons per year. Using the fuel downstream from the pipeline would add just over 16 million metric tons. The higher estimates are that the project would use 39% of the total annual emissions budgets of New Jersey and Maryland.

The commission said counting the emissions was enough and that it did not have to weigh their significance for the project as it had an open proceeding looking into such issues generically.

FERC "did not explain, however, how the pendency of that generic proceeding affects its ability in the meantime to make a case-specific determination here, when it was able to do so in *Northern Natural*," the court said, referencing the first time the commission assessed the greenhouse gas emissions of a proposed natural gas infrastructure project and its impact on global climate change. (See *FERC Assesses Climate Impact of Gas Project for 1st Time*.)

"The anticipated emissions from this project are more than a hundredfold higher than the 100,000 metric tons per year of CO_2e that the commission's interim guidance suggests as a significance threshold," the court said. Even if FERC was not obliged to make a determination, choosing not to do so on the basis of an arbitrary explanation is a violation of the Administrative Procedure Act, it said.

The court also found FERC acted arbitrarily in granting the certificate under the Natural Gas Act because it failed to explain why it discredited New Jersey's study finding no need of new pipelines for the rest of the decade. It also failed to give weight to the state's climate law that requires sizeable and continuous cuts in natural gas use by utilities.

FERC had criticized the New Jersey study for relying on the continued availability of 619 million dekatherms/day of off-system peaking resources that are not under long-term, firm contracts.

"The commission did not, however, identify any past event in which such resources — despite being subject to short-term contracts — were unavailable when needed," the court said. "In fact, the commission recognized that 'downstream capacity has been available to New Jersey shippers in the past through short-term peaking contracts and may be available in the future on the same short-term basis.'"

The project had contracts for the new capacity. Normally such precedent agreements are used to show a market need, but the court faulted FERC for failing to respond to challenges to its reliance on those. While New Jersey local distribution companies signed up for capacity, it is not guaranteed that they will use it to serve their customers.

"If ratepayers assume the cost even when they do not need the capacity, LDCs can afford to contract for additional unneeded capacity, which they can then resell at a profit, even in a soft capacity market," the court said. "Because the commission failed to respond to that challenge to its reliance on precedent agreements with LDCs who subscribed to a majority of the pipeline's capacity, the commission acted arbitrarily." ■

| Shutterstock

FERC Finds SPP Markets+ Tariff 'Deficient' in Several Areas

SPP Expresses 'Full Confidence' it Can Address Commission's Concerns

By Robert Mullin

SPP's Markets+ hit a snag July 31 after FERC issued a deficiency letter outlining 16 problems the RTO must address in the tariff it filed for the proposed Western day-ahead market in March (*ER24-1658*).

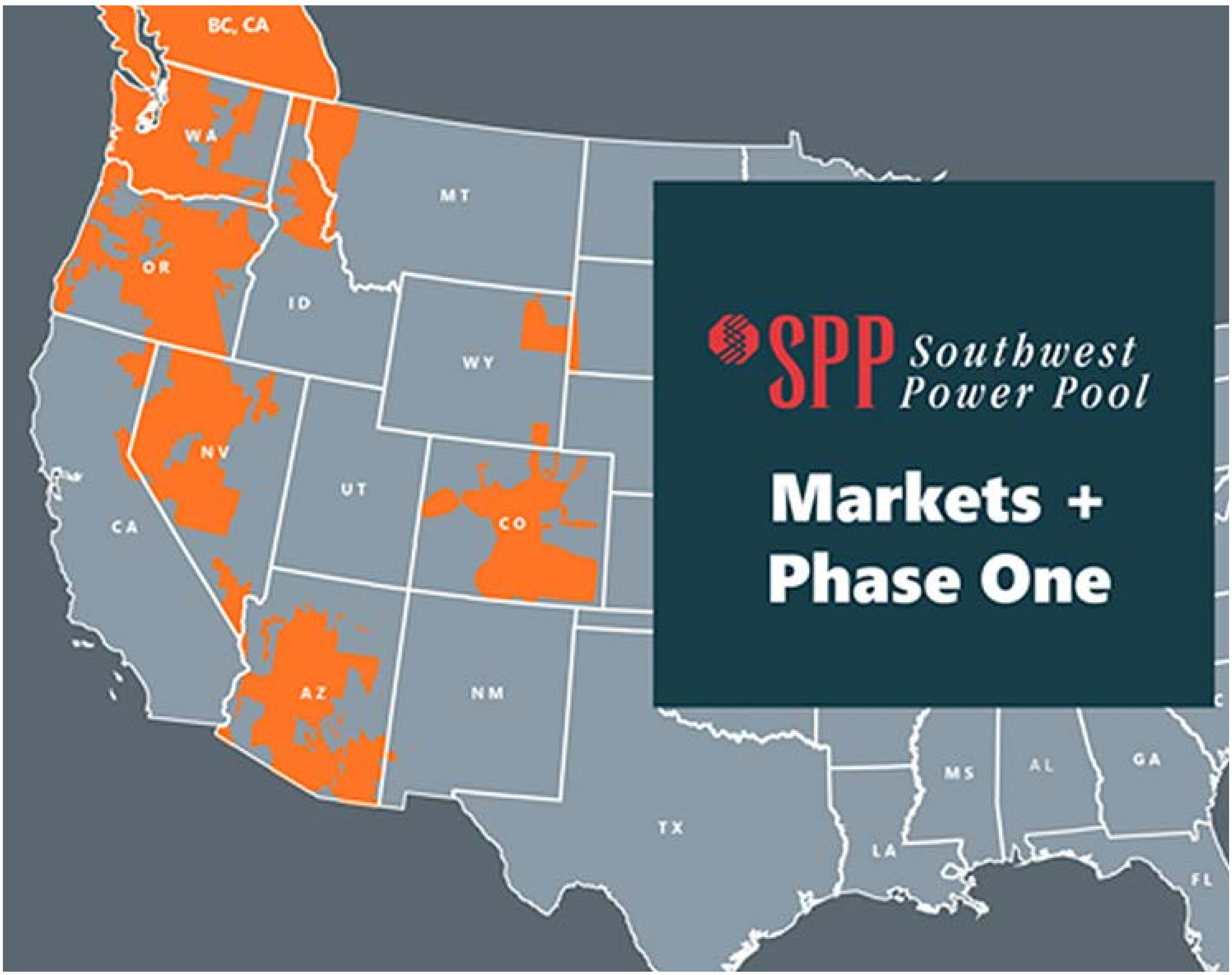
How significant a snag remains an open question.

The commission's letter stipulates that SPP has 60 days to respond. Sources involved in Western market developments, but not authorized to speak for attribution, shared mixed views with *RTO Insider* about SPP's ability to adequately resolve the issues on that timeline, particularly if it must consult with stakeholders on any of them.

They also wondered whether the development would shift decision timelines for entities leaning in favor of joining Markets+. They acknowledged uncertainty about the gravity of the deficiencies, but one source pointed to the seeming "structural" nature of some of FERC's concerns.

For its part, SPP played down the significance in a statement released shortly after FERC released the letter.

"The limited scope of the commission's requests for additional clarity indicates its broad understanding and acceptance of the Markets+ design as proposed, with a need for more detail on some specific, nuanced market characteristics," SPP said. "The additional work necessary to respond to the commission's questions will not negatively impact the Markets+ timeline."



FERC outlined 16 issues SPP must address before winning approval for the RTO's Markets+ tariff. | *SPP*

SPP News

"The Markets+ development timeline has always had flexibility," Antoine Lucas, SPP vice president of markets, said in the statement. "We allowed ourselves time expecting an extended review at FERC, and we're prepared to spend the time necessary to assure the commission we've accounted for every possible contingency in the market's operation."

The deficiencies outlined in the commission's letter deal with multiple subjects in the market's rules, including treatment of transmission, integration with the Western Power Pool's Western Resource Adequacy Program (WRAP), self-schedules, greenhouse gas pricing provisions and offers from hydroelectric resources.

Under the transmission category, the commission asked SPP to clarify provisions around when capacity is considered unavailable for use in Markets+ and explain the process and timeline for communicating unavailability to market participants.

The commission also sought clarity on how "SPP expects that transmission capacity that is opted out [of the market] but that is not otherwise scheduled will be made available for use" — and on the workings of the opt-out process.

Another deficiency relates to the tariff's "Markets+ transmission contributors" provision, which allows participants to contribute their transmission rights to a system operated by a transmission service provider not participating in the market, a rule that prompted a protest from PacifiCorp. (See *SPP Markets+ Tariff Sparks Concerns for PacifiCorp, NV Energy*.)

The commission asked SPP to explain "whether SPP or the Markets+ transmission contributor will be responsible for coordinating transmission schedule changes, curtailments and other operational concerns with the nonparticipating transmission service provider and how this information will be shared, as necessary" and "whether and how ancillary service needs for contributed transmission capacity will be communicated to the Markets+ transmission contributor's nonparticipating balancing authority."

It also asked whether Markets+ or the transmission contributor would be responsible "for potential costs associated with usage of the nonparticipating transmission system, including redispatch costs incurred because of schedule changes."

Regarding the day-ahead market's integration with WRAP, FERC asked SPP to cite the tariff provisions describing "how Markets+ would ensure that WRAP-related exports, imports or wheel-through transactions' firm transmission priorities would be treated and/or retained in the Markets+ framework, and how 'high priority within the market clearing processes' would ensure preservation of a WRAP-related transaction's associated transmission priority."

'Full Confidence'

The deficiency letter additionally seeks clarity on rules related to the treatment of hydroelectric resources, provisions important to Canada-based Powerex and federal power agency Bonneville Power Administration — whose staff in March recommended the agency choose Markets+ over CAISO's Extended Day-Ahead Market. (See *BPA Staff Recommends Markets+ over EDAM*.)

FERC's concerns centered around the calculation of the seasonal hydroelectric offer curve (SHOC), which is designed to estimate the opportunity costs for hydroelectric resources so those costs can be factored into their market offers.

FERC's deficiency letter comes a week after all four U.S. senators from Oregon and Washington sent a letter to BPA Administrator John Hairston urging the agency to delay its decision on joining a day-ahead market until more developments play out around Markets+ and EDAM. (See *NW Senators Urge BPA to Delay Day-ahead Market Decision*.)

"The SPP Markets+ tariff was filed at FERC in April and is still under review," the senators wrote. "FERC has a new slate of commissioners, and it remains unclear whether the tariff, as submitted, will be approved or found deficient. Indeed, deficiency letters for novel filings are common and require additional time and effort to resolve."

"The innovative and complex market structure of Markets+ is proposed under a standalone tariff," SPP's Lucas said in the RTO's statement. "We've always anticipated that a deficiency letter from FERC was a possibility given the intricacies of the market structure. We have full confidence we can quickly and effectively address FERC's request."

CAISO's EDAM tariff won relatively clean approval from FERC last December, with the commission only rejecting a "separable" and temporary measure designed to ensure interim compensation for transmission providers that suffer financial losses during their transition into the new market. The commission approved the ISO's revised version of that measure in June. (See *FERC Approves EDAM Tx Revenue Recovery Plan*.) ■

Company News

PPL Backs Utility-owned Generation in Pa. After PJM Capacity Price Spike

By James Downing

PPL reported GAAP earnings of $190 million for the second quarter and executives focused on changing market dynamics in PJM during a teleconference with analysts Aug. 2.

The call came just days after PJM released the results of its latest Base Residual Auction, which showed significant spikes in capacity prices. (See related story, *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.) CEO Vince Sorgi said PPL is supporting legislative changes in Pennsylvania that would allow the utility to invest in generation.

"With increasing demand and tight supply, we need to do everything we can to protect our customers from such price volatility, including investing further in transmission upgrades to alleviate constrained zones, incorporating additional grid-enhancing technologies to get as much as we can from existing lines, and advocating for legislative changes in Pennsylvania that would drive needed generation development, including authority that would support regulated utility investments in new generation," he added.

PPL is a wires-only firm, having split off its generation when it created Talen Energy in 2015, but given the shift in the generation fleet as demand is on the rise from data centers, PPL would support a major shift in Pennsylvania's regulatory framework.

The capacity auction results show that PJM has a clear need for investment in the transmission system and for new generation, Sorgi said.

Panda Patriot Power Plant located in Clinton Township, Pa. | *Casey Monaghan, CC-BY-SA-2.0, via Wikimedia Commons*

"I think those auction results also would reinforce our strategy in working with the state of Pennsylvania and the other [electric distribution companies] in the state to help resolve the resource adequacy concerns that many of us have been talking about for a while now, in particular in PJM," Sorgi said. "And so we're not going to just sit back and wait for this issue to resolve itself."

PPL has an obligation to serve its customers, and it will do that by expanding the grid and by pursuing legislative changes, he added.

One of the analysts asked Sorgi about the last time restructured states in PJM backed generation, which led to the Supreme Court rejecting a Maryland subsidy that was based on the RTO's capacity auction prices in *Hughes v. Talen Energy Marketing* in 2016. (See *Supreme Court Rejects MD Subsidy for CPV Plant*.) At the time, PPL still owned 65% of Talen, making it the lead complainant in the case.

The biggest difference between now and then is what is in the generation queue, Sorgi argued.

"What we're seeing right now is significant amounts of dispatchable generation being retired with very little dispatchable generation coming on," Sorgi said. "And, so … the big issue is not so much the energy play as the capacity play and making sure that we have enough capacity to serve 24 hours a day, seven days a week, 365" days a year.

PPL will be watching to see if the results from the most recent auction entice new, dispatchable resources to bid into the market in next year's BRA for the 2027/28 delivery year.

"We suspect that the [independent power producers] will want to see more than just this one data point before they're committing to building new dispatchable gen like natural gas," Sorgi said. "So, we'll be keeping an eye on that."

Pennsylvania is taking the issue seriously, Sorgi said, and PPL looks forward to continuing to work with other parties on legislation.

The capacity auction results could lead to PPL's average customers paying $10 to $15 more per month, but Sorgi noted other factors could offset that. The utility has significant interest from new data centers in its territory, with 5 GW worth of interconnection requests at a high level and 17 GW overall, though Sorgi said some of that larger number represents developers submitting speculative projects to find open, economic space on the grid.

Just building out the transmission grid to serve those 5 GW of more secure data centers would lead to them paying more of the transmission side of the bill, offsetting the capacity market's impact to residential consumers, Sorgi said. ■

Company News

Entergy Touts Louisiana Settlements, Beryl Response in Q2 Earnings

By Amanda Durish Cook

Grand Gulf Nuclear Station in Port Gibson, Miss. | *Entergy*

Entergy promoted its response to Hurricane Beryl during its second-quarter earnings call Aug. 1, along with a pair of pending settlements with Louisiana regulators over rates and the Grand Gulf Nuclear Station.

Entergy CEO Drew Marsh told investors to expect settlement filings soon at the Louisiana Public Service Commission to resolve Entergy Louisiana's disputed rate case and claims of mismanagement at the Grand Gulf Nuclear Station in western Mississippi.

Marsh said the Entergy subsidiary System Energy Resources Inc. (SERI) and the Louisiana PSC have struck a $95 million settlement agreement in principle that will *resolve* their longstanding clash over Grand Gulf's poor performance. SERI operates and owns 90% of Grand Gulf and sells the plant's output to Entergy's Arkansas, Louisiana, Mississippi and New Orleans affiliates.

Louisiana regulators are the last to accept a settlement agreement related to Grand Gulf; officials in New Orleans, Mississippi and Arkansas have already accepted nearly $500 million in settlements. (See *Entergy Earnings Call Focuses on La. Resilience Plan, Nuclear Outage and Settlements* and *Former Employee Details Failures at Entergy's Grand Gulf*.)

"Pending approval, this settlement substantially resolves the major litigation at SERI and removes an ongoing challenge for many of our stakeholders," Marsh said. He said Entergy will file a full settlement agreement in the coming days and that he expects the Louisiana PSC to address the settlement at its next business and executive meeting Aug. 14.

The PSC maintained for years that ratepayers are owed hundreds of millions of dollars because Entergy mishandled plant operations, undertook an expensive and excessive plant expansion, and engaged in improper accounting and tax violations that shifted costs to ratepayers.

Marsh said a second settlement with the PSC is on the horizon, this one involving Entergy Louisiana's requested formula rate plan (FRP). He said the settlement involves Entergy dispersing $184 million in customer credits, which includes an increase in income tax benefits for customers, stemming from a 2016-2018 IRS audit of the utility.

The CEO said a successful settlement will mean the utility resolves "all of its outstanding base ratemaking proceedings," including all issues with FRPs prior to the 2023 case.

Last year, Entergy Louisiana sought an approximately 3% rate increase from customers, or about $173 million (U-36959). The utility *argued* that its recent FRPs have not provided it a "reasonable opportunity to recover the costs of serving its customers."

Marsh said the two settlements will provide "important clarity" for stakeholders and will allow Entergy and Louisiana regulators to look ahead to focus on "capturing the significant growth opportunities in front of us." Entergy has identified 5 to 10 GW of new hyperscale data center growth potential across its service territory, he noted.

"We appreciate the hard work of all parties to get to this point," he said of the negotiations.

Marsh also said Hurricane Beryl in early July affected roughly half of Entergy Texas' half-million customers. Uprooted trees caused most of the damage and outages, he said. (See *MISO: Hurricane Beryl Caused Electrical Island in Texas*.)

Entergy estimates that it will recover about $75 million to $80 million in total Beryl-related costs.

"We brought a lot of experience and lessons learned from past storms into this effort, which led to timely, safe and cost-effective power restorations," Marsh said.

He said the storm underscores the need for Entergy Texas' recently filed Ready Resilience Plan, which calls for spending $335 million over an initial three-year period. However, he said about $200 million is contingent on a grant from the Texas Energy Fund.

Entergy Texas is also planning to spend a combined $2.2 billion on new combustion turbine plants in Texas: the 754-MW Legend Power Station in Port Arthur, and the 453-MW Lone Star Power Station in Cleveland, Marsh said. Both plants are expected online in the summer of 2028.

Marsh also said that Entergy will accelerate clean energy development, as exemplified by its early June joint development agreement with NextEra Energy Resources for up to 4.5 GW of solar and energy storage.

"Many of our large customers have clean energy goals, and we are expanding our clean energy capacity to support those objectives," Marsh said.

Entergy reported second-quarter earnings of $49 million ($0.23/share) on an as-reported basis, or $411 million ($1.92/share) on an adjusted basis. This compared to second-quarter 2023 earnings of $391 million ($1.84/share) on an as-reported and an adjusted basis.

The company said the year-over-year decline was mostly attributable to a $317 million settlement charge stemming from a group annuity contract purchased in May to "settle certain pension liabilities." ■

Company News

Dominion Highlights Demand Growth, OSW Progress

By James Downing

Dominion Energy earned $572 million in the second quarter of 2024 and logged six peak demand records in July on the back of Virginia's continued electricity consumption growth, the company said during an earnings call Aug. 1.

"For full-year 2024, we expect DEV sales growth to be between 4.5% to 5.5%, driven by economic growth, electrification and accelerating data center expansion," CEO Robert Blue said during the call.

So far this year, Dominion has connected nine data centers to its system, and it plans to connect an additional six, which will match its recent annual average of 15, Blue said. But the scale of those data centers and their number are growing, while data center developers want them up and running on shorter time frames.

"We're taking the steps necessary to ensure our system remains resilient and reliable," Blue said. "We have accelerated plans for new 500-kV transmission lines and other infrastructure in Northern Virginia, and that remains on track. We were awarded over 150 electric transmission projects totaling $2.5 billion during the PJM open window last December."

The current "open window" for PJM's competitive planning process is expected to be as big, or even larger, due to data center development in Northern Virginia and other parts of the RTO's footprint, Blue added.

The growth of data centers has led the Virginia State Corporation Commission to shift around who is paying for wires in the state, Blue said. Since 2020, residential customers' share of transmission costs has been cut by 10%, while that paid by "GS4" consumers — the largest energy users — has gone up by 9%.

Dominion is also working to expand generation to meet higher demand, looking into small modular nuclear reactors, natural gas storage, and an additional wind farm off the coast of North Carolina once it finishes with Coastal Virginia Offshore Wind (CVOW).

The 2.6-GW wind farm is currently under construction off the coast of Virginia Beach, with 42 monopiles installed so far this season and an additional 30 having been delivered to the utility on shore, which represents 40% of the project's total monopiles.

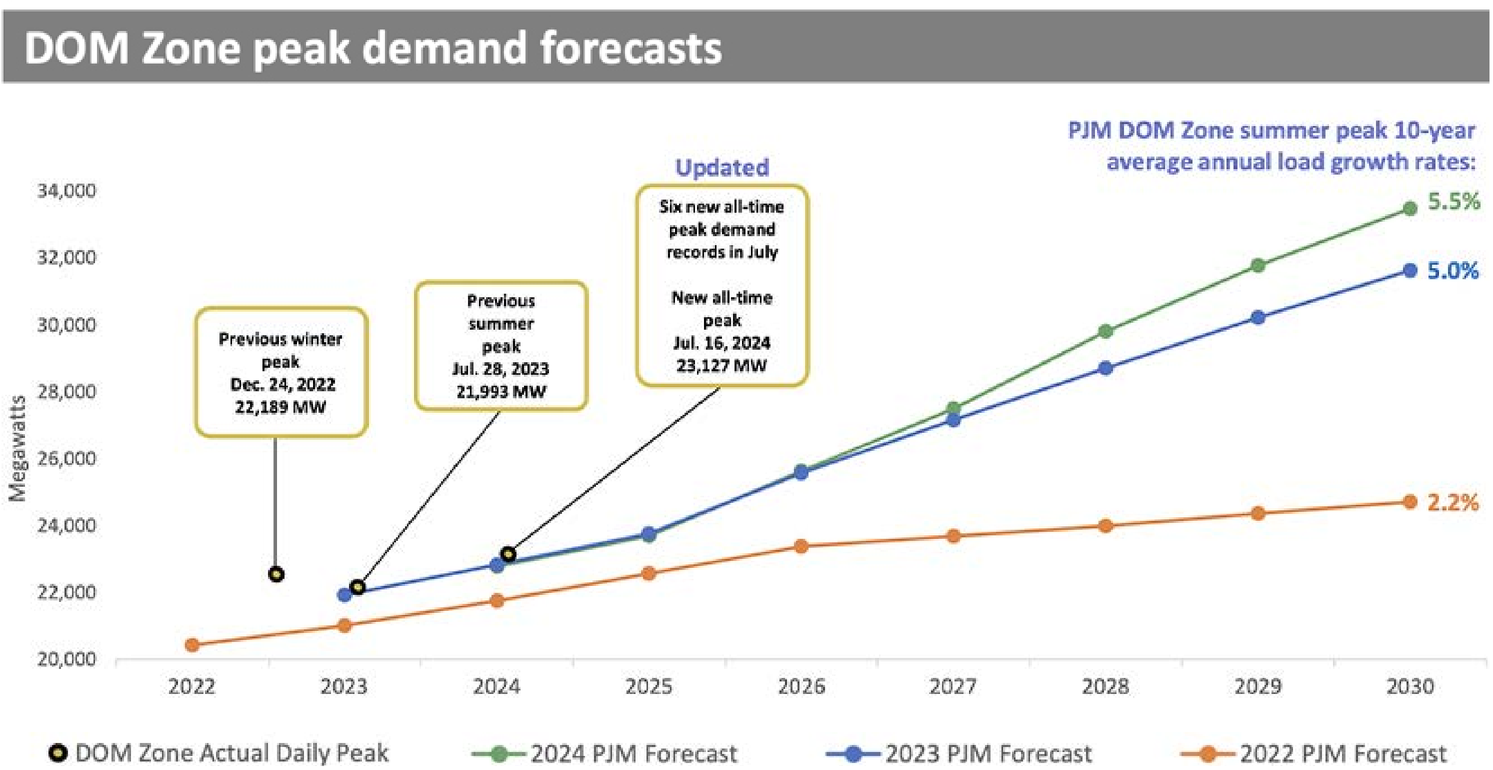
"After a startup period, during which we successfully calibrated our sound verification process in accordance with our permits, we've been able to ramp the installation rate markedly, including achieving two monopile installations in a single day on July 21, and again on July 28," Blue said.

Other parts of the massive project continue to be on schedule, with Blue saying Dominion should install the first cable to connect the power plant to the grid during the third quarter.

"The schedule for the manufacturing of our turbines remains on track," Blue said. "Fabrication of the towers for our turbines began in June."

Dominion will not install its first turbines for the CVOW until 2025, but Blue said that process has begun for the Moray West wind plant off Scotland, which is using the same Siemens Gamesa turbines and has already shipped power to the United Kingdom's grid.

"The lessons learned from that project will benefit our project installation in the future," Blue said. ■



A chart from Dominion showing how demand forecasts for its territory have gone up in recent years, with actual peak demand records for its footprint. | *Dominion Energy*

Company News

AEP Planning for 15 GW of Data Center Load

By Tom Kleckner

American Electric Power executives say they're embracing large loads and, fortunately for them, they say they have firm commitments for more than 15 GW of load coming from just data centers by 2030.

AEP told financial analysts during its July 30 second quarter earnings call with financial analysts that it's seeing "unprecedented" load growth, split primarily between Texas and its PJM footprint. Commercial load has increased 12.4% over the second quarter of last year as new data processing facilities came online, the company said.

"We continue to see strong interest in Ohio and Texas, as well as several of our vertically integrated states, from customers looking to develop new data processing facilities," interim CEO Ben Fowke said during the company's call. "Affordability remains top of mind, and we're working to ensure that the investments made in the grid to support this increased demand are allocated fairly and provide benefits to all customers."

Noting AEP's system-wide peak at the end of last year was 35 GW, Fowke said the company continues working with data center customers to meet their increased demand, but also ensuring contracts and new initiatives are "fair and beneficial" for all customers. He said AEP would provide details on its generation and transmission capital investment necessary to meet demand later this year.

"I want to emphasize that it's critically important that costs associated with these large loads are allocated fairly and the right investments are made for the long-term success of our grid," Fowke said.

AEP subsidiary Public Service Co. of Oklahoma (PSO) in June announced it will seek regulatory approval of an agreement to purchase Green Country, a 795-MW natural gas facility.

Data center growth means AEP will have to build more transmission. | *AEP*

Peggy Simmons, executive vice president of utilities, said the transaction will help PSO meet SPP's higher planning reserve margin, which was increased to 15% from 12%.

"This was a very proactive approach that the team took to go out and find some affordable assets that we can bring onto the system," she said.

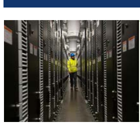
AEP *reported* second-quarter earnings of $340 million ($0.64/share), down from 2023's second quarter earnings of $521 million ($1.01/share). The company reaffirmed its 2024 operating earnings guidance range of $5.53-$5.73/share and its 6%-7% long-term growth rate.

Incoming CEO Bill Fehrman, who takes over AEP's top job Aug. 1, did not participate in the call. Fehrman replaced Julie Sloat in June after his predecessor parted ways with AEP in February following just one year as CEO. (See *AEP Selects Industry Veteran as Next CEO*.)

"With Bill's expertise and diverse background, you can anticipate a smooth transition and continuity of strategic direction. Expect more focus on execution," said Fowke, who served as interim CEO and will advise Fehrman during a transition period.

The company's share price rallied late July 30 to close at $98.14, up $1.07 from its previous close. ■

Northeast news from our other channels



Summit to Focus on Developing Energy, Economy

NetZero Insider

Mass. Lawmakers Fail to Pass Permitting, Gas Utility Reform

NetZero Insider

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

Company News

PSEG Planning for EV, Data Center Growth

Utility Unconcerned by Talen Controversy, Election Fallout

By Hugh R. Morley

Public Service Enterprise Group is seeing "slow but steady" electric vehicle growth in New Jersey but has yet to turn down any interconnection requests for EV chargers to handle the increase, CEO Ralph LaRossa said in the utility's second-quarter earnings call July 30.

"We have the capacity," he said. "But we're upgrading that last mile. So that's really playing out exactly the way we expected it to."

Because of the unique "condensed nature of our housing and our commutes" in New Jersey, he said, EVs "have not had the same challenges and pressure that maybe the rest of the country has seen as far as the expansion that was expected."

New Jersey last year put an additional 62,426 new EVs on the road, a 68% increase over 2022, which has prompted some advocates to suggest the state is in reach of its goal of having 330,000 EVs in the state by 2025. The rise occurred as some analysts say EV uptake elsewhere around the nation is slowing.

The New Jersey Coalition of Automotive Retailers says that the state's affluent population is less bothered than drivers in some states by the higher price of an EV, but the organization is skeptical that the target can be reached. (See *NJ EV Incentives Target Low-income Buyers*.)

LaRossa said the rise in EV charging, along with growing interest from developers in putting data centers in the state, "is expected to drive load growth and system investment in these in the future." Responding to a question from an analyst, he said he sees little risk in investing for continued EV growth, even if former President Donald Trump is re-elected this year.

"The only question, and we've talked about this before, is will you have 100% EVs by 2035, or will we get a 50% on that test?" he said. "And a 50 on that test is still going to be quite a bit of market penetration for the electric vehicle industry here."

Data Centers

LaRossa said the utility is heavily focused on positioning itself to take advantage of interest from data centers in locating in the state, and especially those interested in co-locating next to the three nuclear plants owned and operated by PSEG in South Jersey.

He said the utility has "experienced an increase in new business requests and feasibility studies from potential data center customers across our service area compared with 2023 activity, which, combined with increased electric vehicle charging, is expected to drive load growth and system investment in these in the future."

PSEG takes proposals seriously once the developer has moved beyond the engineering phase, he said. He added that "we're seeing several hundred megawatts of data centers that are moving into that scenario here in New Jersey," and two or three times as many projects that are in earlier stages.

LaRossa noted that Gov. Phil Murphy on July 25 signed a law (*S3432/A4558*) creating a $500 million program to offer tax credits to encourage artificial intelligence companies to locate in the state.

He said a co-located data center has two benefits for the state's economic development ambitions.

"It's not necessarily just that it's co-located," he said. "It's the fact that it's a hyperscale data center. It's going to provide a clear signal to AI companies that are looking to locate here in New Jersey and in the region, that the infrastructure is here up and running and ready to go for their businesses to thrive," he said.

Talen Controversy

LaRossa said his attitude has not changed in response to the recent controversy over Talen Energy's deal to divert capacity from its Susquehanna Nuclear Plant to serve a data center on the same site.

The project, which Talen developed next to its northeastern Pennsylvania plant and sold to Amazon Web Services, has drawn protests at FERC from parties who argue that it could siphon power meant for other clients, shifting costs and threatening reliability. (See *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC*.)

"That's not shifting us in any way, shape or form," LaRossa said, adding that the utility will be guided by its commitment to supporting Murphy's economic development plans. "We are going to continue in that effort.

"I will say this to you. I'm a little bit concerned about co-located load as it impacts other industries," he said. "If you really think about co-located load, that doesn't just apply to data centers. That's for combined-heat-and-power plants; it's for cogeneration units.

| Shutterstock

"So, depending upon where this goes, while I'm concerned about data centers, I'm just as concerned about everything from rooftop solar behind the meter to cogeneration that might be taking place."

Still, he added in response to a question from an analyst, whatever outcome emerges from the Talen case would not affect, or even delay, any proposal that might emerge for co-locating a facility next to PSEG's three nuclear plants.

"Every deal is going to be very specific. I think the way our nuclear facilities are configured will be different than a nuclear facility down the street." he said. "So, each one of those will be looked at differently, whether it's by PJM, in its current rules that coexist for co-located load, or FERC when they come out with some sort of a process, if they do under the current challenge that's there."

PSEG's second-quarter results this year fell short of those in 2023. The company reported net income of $434 million ($0.87/share), compared with $591 million ($1.18/share). It brought in about $2.4 billion in total revenue during the quarter, a slight increase from last year. ■

Company News

Xcel Energy Beefs up Wildfire Mitigation Plans

By Tom Kleckner

Xcel Energy says it relies on industry best practices and its own experience in beefing up wildfire mitigation plans for its operating companies.

In Colorado, where its affiliate faces nearly 300 lawsuits after the 2021 Marshall fire destroyed more than 1,000 homes, killed two people and caused more than $2 billion in property damage, Xcel recently filed a $1.9 billion wildfire mitigation plan that updates the previous one. It will serve as a template for wildfire mitigation plans in Texas and New Mexico and the company's other states.

"I'm really proud of what we're going to accomplish on the operational side to provide the real-time risk reduction that we need today to give us the time to make the necessary enhancements and system resiliency and hardening for our system over time," Xcel CEO Bob Frenzel told financial analysts during the company's second-quarter earnings call Aug. 1.


Xcel Energy is focused on wildfire mitigation in its service territory. | *Xcel Energy*

The Colorado plan integrates industry experience, incorporates evolving risk assessment methodologies, adds new technology and expands the scope, pace and scale of programs reducing wildfire risk, Frenzel said. It also benefited from the "hard work of the people that have come in front of us in California," he said.

"We expect to dramatically reduce our wildfire risk based on their experiences and doing some of the lessons learned from all of those organizations. But that shouldn't be taken as anything other than a huge focus that we also have in Texas and in [New] Mexico around our plans there," Frenzel said.

Xcel has been linked to February's Smokehouse Creek fire in the Texas Panhandle, the largest in state history. It has acknowledged its infrastructure likely started the fire. The company plans to file a resiliency plan in Texas for its Southwestern Public Service subsidiary later this year.

The Minneapolis-based company reported second-quarter earnings of $302 million ($0.54/share), as compared to the same period a year ago of $288 million ($0.52/share). Xcel's ongoing earnings reflected the recovery of increased infrastructure investments and warmer than normal weather, partially offset by increased depreciation, interest charges and operations and maintenance expenses.

The company reaffirmed its year-end guidance of $3.50-3.60/share. It has met year-end expectations 19 straight years.

Xcel's share price closed at $59.75, up 2.5% after the earnings release. ■

Company Briefs

Vistra Gets OK to Operate Comanche Plant Through 2053

Vistra announced last week that the Nuclear Regulatory Commission approved its request to extend the operation of Comanche Peak Nuclear Power Plant in Texas an additional 20 years beyond its original licenses.

The 1,259-MW Unit 1 began operation in 1990, and the 1,245-MW Unit 2 in 1993; with the approval they can now operate through 2050 and 2053, respectively.

"With demand for electricity growing at a rapid pace, reliable sources of power, like Comanche Peak, are going to be absolutely essential to meeting that need," Vistra CEO Jim Burke said in a statement.

More: *Vistra*; *Nuclear Engineering International*

Chevron to Move HQ to Houston from California

Chevron, the second-largest U.S. oil company, is moving its headquarters to Houston from California, formalizing a long-expected breakup with a state that has pushed aggressively to address climate change.

The company's center of gravity has been in the Houston area, where it employs roughly 7,000 people, compared with around 2,000 at its current headquarters in San Ramon, near San Francisco. Relocating to Houston will "enable better collaboration and engagement both internally and externally," CEO Mike Wirth said last week.

Chevron's announcement came as the company reported second-quarter earnings last week that missed the expectations of Wall Street analysts. The company said profit fell 26%, to $4.4 billion, from a year earlier.

More: *The New York Times*

BP Raises Dividend as Q2 Profit Beats Expectations

BP last week reported stronger-than-expected net profit for the second quarter and raised its dividend, despite previously warning of significantly lower refining margins.

The company posted underlying replacement cost profit, used as a proxy for net profit, of $2.8 billion for the second quarter, a slight increase over the $2.6 billion earned in the same period last year.

BP increased its dividend by 10% to 8 cents per share, up from 7.27 cents. CFO Kate Thomson last week said that the firm's decision to boost shareholder returns "reflects the confidence we have in our performance and outlook for cash generation."

More: *CNBC*

Federal Briefs

Hydropower Industry Sues Feds over New ESA Rules

Hydropower companies are challenging in court an Endangered Species Act rule change that the Biden administration says protects vulnerable fish but that the industry considers burdensome and unjustified.

In a lawsuit filed last week, the National Hydropower Association and the Northwest Hydroelectric Association seek to reverse the administration's rule that mitigation measures can be required as a condition of obtaining a hydro license.

The Fish and Wildlife Service and NOAA Fisheries imposed the changes in May as part of a broader effort to update and strengthen ESA regulations.

More: *E&E News by POLITICO*

DOE Funds $63M Battery Recycling and Industrial Modernization

The Department of Energy last week announced $63 million in funding to help state and local governments expand battery recycling and make technologies such as advanced sensors and modelling more accessible to small- and medium-sized manufacturers.

"The funding announced today will equip small- and medium-sized manufacturers with cutting-edge technologies to improve operations efficiency and expand battery recycling, removing barriers to advancement and bolstering the nation's competitive standing," Secretary Jennifer Granholm said in a statement.

The funding includes $41 million for the second phase of the $50 million granted by the Infrastructure Investment and Jobs Act for state and local government battery recycling programming. In the first phase, DOE selected battery recycling projects that are expected to catalyze more than $14.4 million in investments. The second phase will "boost state and local governments' ability to support statewide and local battery recycling programs," according to the department.

More: *Power Technology*

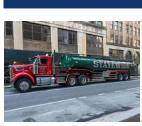
FERC to Hold Tech Conference on Co-location of Large Loads

FERC announced last week that it will convene a commissioner-led technical conference this fall to discuss issues related to the co-location of large loads at generating facilities.

The commission did not set a date for the conference, which will be held at its headquarters in D.C. and be open to the public. "A supplemental notice will be issued with the date and time of the technical conference, as well as further details regarding the agenda and any changes in logistics," FERC said.

More: *FERC*

Northeast news from our other channels



Opposing Sides Want to Speed, Slow NY Cap-and-invest

NetZero Insider

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

State Briefs

FLORIDA

Judge Sentences Former JEA CEO Zahn to Prison

U.S. District Judge Brian Davis last week sentenced former JEA CEO Aaron Zahn to four years in prison on conspiracy and wire fraud charges.

Zahn, 44, led JEA when the utility's board put the company up for sale in 2019 and also approved an employee incentive plan that prosecutors say would have stolen hundreds of millions of dollars of sales proceeds from taxpayers and given them to employees. Prosecutors said Zahn conspired to create the plan and then hid the high cost of it from the board.

In addition to the four-year prison sentence, Zahn will serve one year of supervised release. Davis agreed to give Zahn up to 90 days to turn himself in to start the sentence.

More: *Jacksonville Florida Times-Union*

IDAHO

Ada County Rejects Solar Farm

Ada County Commissioners last week moved to reject a proposed 1,419-acre solar farm.

Commissioners cited extensive community opposition and personal reservations in rejecting the solar farm. Concerns about the environment and how the farm would alter the character of the surrounding agricultural community were principal factors amongst residents.

Commissioners emphasized the move was not a referendum on solar energy, but rather an effort to retain the character of the farming and agricultural community.

More: *Boise Dev*

ILLINOIS

Feds Reject Argument that Supreme Court Ruling Saves Madigan

Federal prosecutors last week rejected the notion that charges against former Illinois House Speaker Michael Madigan should be tossed because of a recent U.S. Supreme Court ruling.

The prosecutors took the position as they continue to fend off potential damage from the high court's decision in the appeal of former Portage, Ind. Mayor James Snyder. The justices found that a statute criminalizing bribery among state and local officials does not also criminalize after-the-fact rewards known as "gratuities." Madigan's attorneys sought dismissal earlier this month of 14 of the 23 counts against him, partly because of the ruling. Prosecutors countered that Madigan and his co-defendant, Michael McClain, "intended to engage in quid pro quo bribery."

More: *Chicago Sun-Times*

MISSOURI

Evergy Seeks 13.99% Rate Increase

The Public Service Commission last week held a public hearing on Evergy's 13.99% rate increase request.

Evergy spokesperson Gina Penzig said the increase is needed to increase grid reliability and add generation resources.

More: *KQ2*

NORTH DAKOTA

PSC Gathers Info on Natural Gas Providers' Rate Increases

The Public Service Commission last week held a public hearing on rate increases requested by Northern States Power Company and Montana-Dakota Utilities.

Northern States Power Company is seeking an estimated $8.5 million in revenue. It would add roughly $6.75 per month for the average residential customer. Montana-Dakota Utilities is seeking $11.6 million in revenue, which would increase the average monthly gas bill by about $5.90.

Northern States said the increase is needed to recoup costs for meter replacements and upgrading outdated infrastructure, while Montana-Dakota said it's necessary for pipeline replacement projects and to operate and maintain its natural gas system.

More: *News from the States*

PENNSYLVANIA

PUC Files Complaint on Peoples Gas for Safety Violations in 2021 Explosion

The Public Utility Commission last week filed a 22-count complaint against Peoples Natural Gas for alleged safety violations stemming from a 2021 explosion that killed one person, injured four others and leveled a home.

A serviceman sent to the scene of a gas leak — that was caused by a contractor's drill piercing a main — failed to shut off the gas supply, notify emergency services or evacuate nearby homes before the explosion, the PUC stated. The explosion happened 40 minutes after he arrived and 18 minutes after he reported "a serious incident involving suspected bore or missile damage" to his supervisor, according to the complaint.

The PUC is recommending an $800,000 fine and a series of procedural reforms designed to enhance the company's response to future reports of leaking gas.

More: *Altoona Mirror*

TENNESSEE

Enviro Groups Urge TVA to Deny xAI Supercomputer Power

Environmental groups last week sent a letter to the TVA Board of Directors with a list of concerns about Elon Musk's Memphis supercomputer.

The Southern Environmental Law Center sent the letter on behalf of Memphis Community Against Pollution; the Young, Gifted and Green; the Sierra Club Tennessee Chapter and the Sierra Club Chickasaw Group. The letter cites the supercomputer's impact on the air, water and electrical supply in Memphis and Shelby County. The groups also expressed frustration with how quickly the supercomputer facility is being built without local approval or management.

Musk's "Gigafactory of Compute," the world's largest supercomputer, requires 150 MW.

More: *WMC*