ISSN 2377-8016 : Volume 2024/Issue 5 ▪ February 6, 2024

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

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FERC Gets Dueling Competition Studies in Transmission NOPR Docket

Pro-competition Group Responds to December Study from Incumbent Utilities

By James Downing

With FERC potentially issuing a final rule on transmission planning this year, the issue of whether it should curtail competition is the subject of dueling reports filed in the Notice of Proposed Rulemaking's docket (RM21-17).

The Electricity Transmission Competition Coalition (ETCC) filed supplemental *comments* Feb. 1 with a report extolling transmission competition's benefits in response to a *report* filed in December from a group called Developers Advocating Transmission Advancement (DATA) arguing the opposite.

DATA is made up of transmission owners Ameren Services, Eversource Energy, Exelon, ITC Holdings, National Grid USA, Public Service Electric and Gas, and Xcel Energy.

"Contrary to their plea to revisit the commission's prior determinations supporting competitive solicitations under Order No. 1000, the incumbent TOs fail to demonstrate that cost-of-service regulation is as effective as competition in establishing just and reasonable transmission rates," ETCC said.

Competition disciplines cost, but regulated utilities with monopolistic rights and guarantees projects will have an incentive to press for the highest returns possible, it said.

"In a regulated cost-of-service model, the utility has an inherent incentive to spend more because the utility can then earn more through a return of and on its investment," ETCC said. "Through competition, a developer has an inherent incentive to find an innovative and efficient solution, while an incumbent with monopolistic, exclusive rights has no such incentive."

DATA's report argued that those promised cost savings have not appeared in the decade plus since Order 1000, highlighting the costs of projects that were subject to competition. While the docket had 774 filings as of press time Feb. 1, DATA argued that its report includes information FERC had not seen yet.

ETCC called the DATA report "an unverified, authorless and self-serving white paper/pamphlet," which, it continued, lacks credibility and was filed in the docket at the last minute — 15 months after the reply comment deadline.

"The resulting analysis shows that, rather than

| © RTO Insider LLC

Order No. 1000-mandated competition leading to cost savings, final costs for projects selected through competitive solicitations tend to exceed cost baselines by at least 6%," DATA said. "Furthermore, with certain reasoned adjustments, average baseline exceedances are calculated in the 12 to 19% range."

Winning bids for projects from competitive processes do not represent final project costs because what is actually recovered tends to exceed those considerably, DATA argued. And competitive proposals often include cost caps, but DATA said those do not appear to offer meaningful cost-containment protections for customers, with final project costs exceeding them.

DATA's report was in response to a *report* the Brattle Group prepared for LS Power in 2019 that found that competitive forces saved 20 to 30% compared to monopoly projects, which has been widely quoted by supporters of competition. That report suffered from a lack of finalized projects, DATA argued, so Brattle had to use cost estimates.

Brattle's report includes 22 competitively bid projects, but just nine of those were completed in a way that allows for apples-to-apples comparison, DATA said. Some of the projects did lead to cost savings, but they were outweighed by ones that came in above cost, and DATA found they led to 6% higher costs compared to their baselines.

ETCC noted that the Brattle report already drew a *response* the year it was released from Concentric Energy Advisors, to which Brattle then *responded*. The California Public Utilities Commission and competitive transmission developers had discussed those two 2019 reports in the NOPR docket.

"The incumbent TOs cherry-pick data from select competitive projects, misleadingly describe those projects and advance anecdotes that do not represent the spectrum of the competitive transmission experience," ETCC said.

Some of the missing projects are successful competitive projects that led to cost savings and thus go against the TOs' narrative, it added.

"Critically, the incumbent TO white paper rests on the flawed premise that costs exceeding a competitive developer's initial winning bid will be recovered from consumers," ETCC said. "Unlike the incumbent utilities, which can generally flow their project cost overruns into rates, most competitive developers cannot pass through cost overruns to consumers because binding cost caps and cost-containment commitments are necessary for a competitive developer to win a solicitation and be awarded a project."

Projects that go over a hard cap need to get approval from FERC to actually recover those costs, but even those that allow for adjustments because of inflation, or recovery of some cost overruns, are better than monopolistic projects without any cost containment, ETCC said. Only one of the nine projects DATA covered sought cost recovery above its cap.

ETCC also argued that DATA's paper cut out most of the 22 projects Brattle studied to get the results it wanted. DATA also ignored the issue of inflation, which has affected projects built by incumbent utilities as well, it said.

Xcel's Minnesota Energy Connection has more than doubled from the company's initial estimate to $1.14 billion, and Ameren's 345-kV Pana-Mt. Zion-Kansas-Sugar Creek line saw its costs grow by 44% from its initial development, ETCC said.

"Critically, because these projects were not competitively awarded and were instead developed without any cost containment, customers absorb these project cost overruns through formula transmission rates," ETCC said. "Cost overruns are common among incumbent utility projects." ■

FERC/Federal News

FERC Releases Latest Version of ISO/RTO Metrics Report

By James Downing

FERC on Jan. 30 released the latest iteration of its Common Metrics Report on ISO/RTO markets, which evaluates the performance and benefits of organized markets.

The commission has released these reports every few years since Congress' Government Accountability Office suggested it do more to track the performance and benefits of ISO/RTOs back in 2008. The report shows the different fuel mixes from FERC's six jurisdictional organized markets and how much they each rely on demand response.

Some past reports have included similar data from utilities outside of ISO/RTO footprints, but none of them responded to FERC's efforts this time.

The highest share of DR is in CAISO at 10%, while MISO, NYISO and PJM each have 3-6%. ISO-NE and SPP both reported less than 2%. DR in SPP grew significantly in 2022, hitting about 2% after minimal levels in earlier years.

ISO-NE and MISO added generation in each year from 2019 to 2022, while both PJM and NYISO lost capacity overall during that time.

FERC staff collected information on 29 common metrics across the six ISO/RTOs split across three broader categories: administrative and descriptive metrics; energy market metrics; and capacity market metrics.

CAISO, ISO-NE, MISO and NYISO all had actual reserve margins below their expected levels between 2019 and 2022, with MISO seeing the biggest gap. Only PJM had higher actual reserve margins than expected in all four years, while SPP flipped between both categories every year.

Every organized market reported that natural gas was their single largest fuel type from 2019 to 2022 with NYISO seeing the biggest increase in the fuel — from 58% to 64% — while ISO-NE, MISO and PJM each reported a modest increase. CAISO saw natural gas share fall from 49% to 41% over the period, while SPP saw a more modest drop from 43% to 40%.

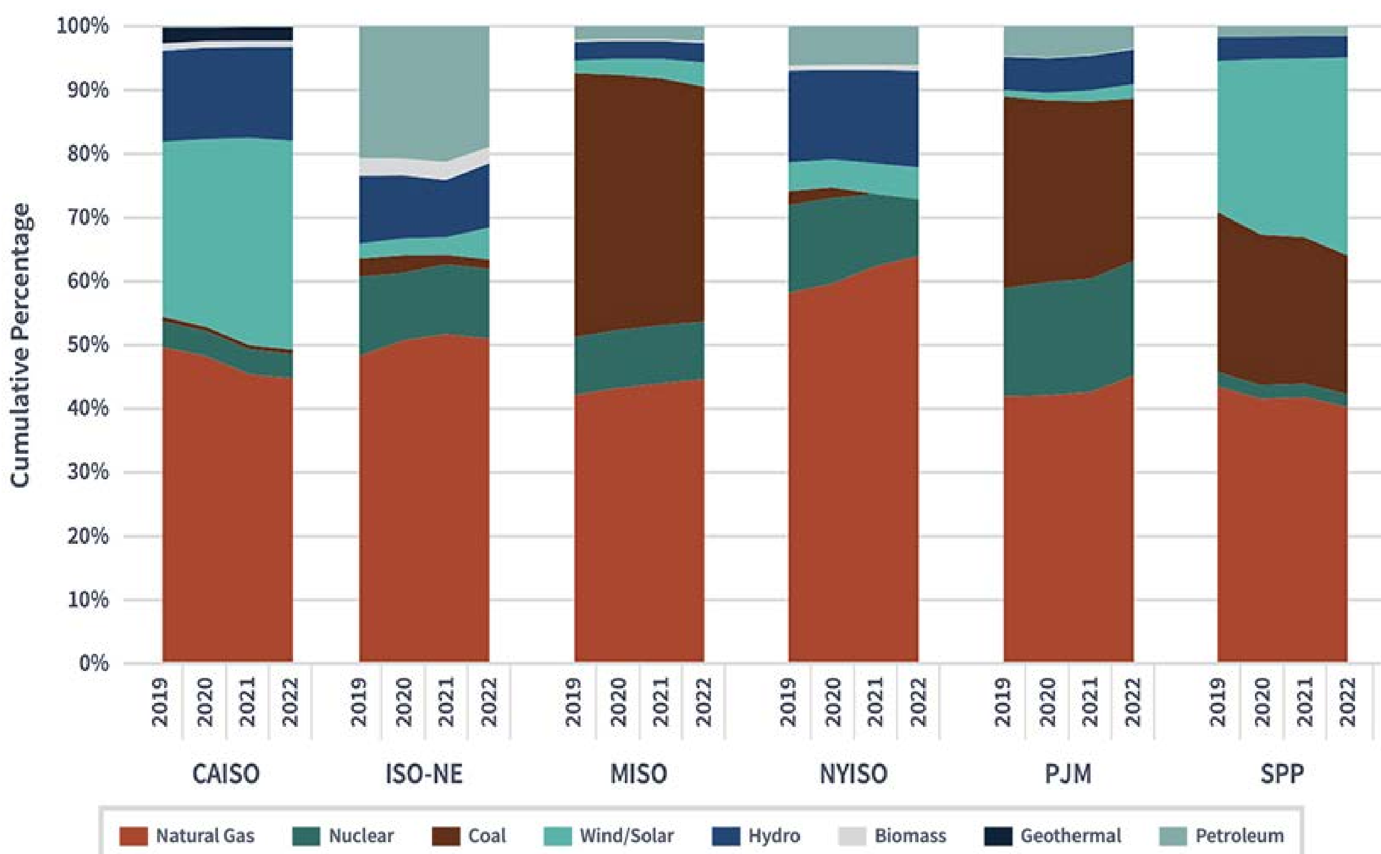
"The decline in the share of natural gas-fired capacity in these regions is likely driven by the relatively large increases in wind and solar generating capacity, instead of natural gas retirements," the report said.

MISO, PJM and SPP all had a significant amount of coal in the fuel mixes, and all saw it drop. Coal in PJM fell from 30% in 2019 to 25% in 2022, MISO saw it fall from 41% to 37% and SPP from 25% to 22%. The other markets all reported less than 3% coal in their markets.

SPP and CAISO had the highest shares of installed wind and solar generating capacity, with the two renewables representing 31% of capacity in SPP and 30% in the California ISO.

"The largest relative increase in generating capacity of these resource types occurred in SPP, where the share of wind and solar capacity increased from 24% in 2019 to 31% in 2022," FERC said.

The report also included how often each market had to issue Energy Emergency Alerts across the four years studied, with CAISO seeing 16, MISO 10, PJM six, SPP five and ISO-NE one. ■



A FERC chart showing how the fuel mix has changed in recent years by ISO/RTO. | FERC

FERC/Federal News

FERC to Return $13.6M to BP from 2008 Enforcement Case

Court Ruled FERC Partly Overstepped Its Jurisdiction and BP Still Paid $10.75M

By James Downing

FERC issued an order Jan. 31 approving the return of $13.6 million in penalties it had collected from BP over a case of alleged manipulation of Houston Ship Channel natural gas prices after Hurricane Ike in 2008.

The commission collected $24.36 million in fines, plus interest, from BP for allegedly keeping natural gas prices at the Houston Ship Channel lower than those at the Henry Hub in Louisiana and losing money in physical trades, which benefited its financial positions and led to overall profits. FERC first issued a show cause order in the case in 2013, and years of litigation followed until a decision from the Fifth Circuit Court of Appeals came down in October 2022.

The commission had argued it should have jurisdiction over any transaction that impacts the interstate natural gas markets it polices, but the court disagreed.

BP only shipped gas over intrastate pipelines regulated by the Texas Railroad Commission in the alleged scheme, but some of that natural gas previously had crossed state lines, meaning it fell under FERC's jurisdiction. The court said only that interstate gas could be part of the federal regulator's enforcement action.

BP and FERC's Office of Enforcement entered into a settlement that trimmed the penalty to $10.75 million, following the court's findings, which meant the firm had paid an extra $13.6 million.

The oil major agreed it would not seek recovery of $250,295 of disgorgement of unjust profits, which ultimately was paid to three Texas Low Income Home Energy Assistance Program (LIHEAP) programs.

BP made a filing in November arguing FERC itself should issue an order requiring it be repaid for the $13.6 million. The order Jan. 31 directed the director of the Financial Management Division in the Office of Executive Director to wire BP the money. ■

Aerial view of the Houston Ship Channel | *Shutterstock*

Parties Split on Biden Administration Deal on Snake River Dams

By James Downing

House Republicans on Jan. 30 lambasted a deal that the Biden administration struck between Oregon, Washington and four tribes on four dams along the Snake River, claiming it will lead to their breaching and threaten power reliability and other industries.

The administration announced the *deal* in December, and Democrats on the House Energy and Commerce Subcommittee on Energy, Climate and Grid Security argued it would end uncertainty around the four Bonneville Power Administration (BPA) dams, which had been under litigation for decades because of their impact on salmon and other fisheries.

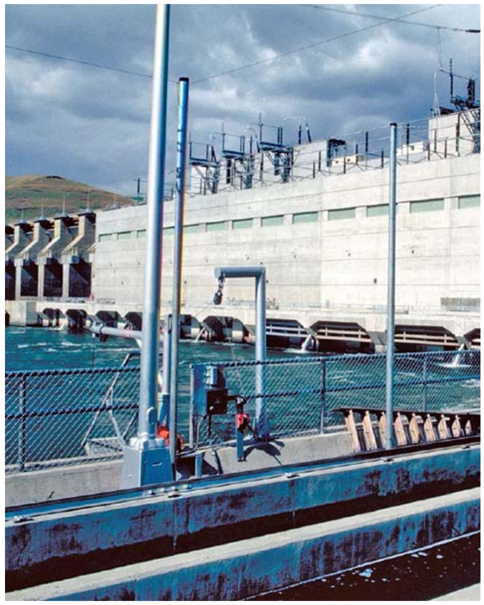
The Columbia River System is the "beating heart" of the Northwest, and removing the four dams would imperil electric reliability in that region and the broader West, committee Chair Cathy McMorris Rodgers (R-Wash.) said.

"While the administration will say only Congress has the authority to breach the dams, they wasted no time entering into commitments that bypass Congress and agreeing to spend more than a billion dollars to achieve their political goal, again without congressional approval," she added. "What's worse is, despite my repeated calls for transparency, the White House actively and deliberately left out voices of those who depend on the river system the most. Dozens of stakeholders and utility companies practically begged to be heard in this process, only to be turned away, shut out and ignored."

The Columbia River is home to 13 species of salmon that are endangered, and the tribes who live along it have depended on their annual runs for thousands of years, said subcommittee Ranking Member Diana DeGette (D-Colo.).

"Construction and operation of the dams, private dam building and population growth have negatively impacted wild fish populations," DeGette said. "This has led to years of litigation and court rulings, which have found operation of the dams violates the Endangered Species Act."

Treaty obligations to the tribes allow them to harvest 50% of the salmon catch; the fish's declining numbers violated those obligations, said Yakama Nation Tribal Council Member Jeremy Takala. "My people's tribal treaty rights demand it, as the U.S. Supreme Court recently



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

affirmed treaty fishing rights include the right to actually catch fish, not just to dip our nets in empty waters without salmon."

Takala was involved in the negotiations on behalf of his tribe that led to the deal, which came out of a recent court case.

"In 2021, a group of plaintiffs filed a motion for the most recent district court litigation seeking to further alter hydropower operations in the basin," said White House Council on Environmental Quality Chair Brenda Mallory. "The United States government had a choice: defend and face the prospect of another injunction, or work with the plaintiffs and others in the region to find a path forward that could lay the groundwork for an enduring partnership with mutually beneficial solutions. We chose partnership."

The CEQ convened an interagency group and engaged mediators to facilitate a dialogue with tribes and states in the region, which last fall led to a Presidential Memorandum of Understanding on preserving fish stocks in the region. In December, the White House announced the deal with the "six sovereigns" (the two states and four tribes), which includes more fishery restoration efforts, funding for clean energy development by the tribe and a pause of at least five years in the ongoing litigation, with the possibility of another five.

BPA has been working for decades to improve the environment for salmon and other fish. The deal includes additional funding to improve fisheries over the coming decade, said CEO John Hairston. BPA filed a rate impact statement showing that those additional funds would only add an average of 0.7% to customers' monthly bills through 2035.

National Rural Electric Cooperative Association CEO Jim Matheson disputed the relatively low cost estimates coming out of BPA.

"If you want to build replacement power when you breach these dams — which I don't think you can do and have the same comparable resource, by the way — you're going to spend a lot of money, and it will have a big impact," Matheson said.

The four dams are also highly complementary to the region's wind resources because they all have technology that allows them to ramp up and down quickly depending on how hard the wind is blowing, Matheson said.

The agreement filed in court recognizes that Congress must enact legislation to actually breach the dams, but Matheson argued the deal was piling more and more compliance costs on them.

"This settlement effort is a way to force Congress' hand and put Congress in a position where breaching is more likely," he said.

Matheson declined to use the word "secret" that was often repeated by Republicans at the hearing about the negotiations, but he did note that just six parties were in the room with the federal government, and so far NRECA and other industry representatives' letters taking issue with it have not been answered.

The Yakama Nation's Takala opened his testimony by calling claims about secret negotiations with "radical environmental groups" as claims "fueled by fear and misinformation."

"This agreement is a historic opportunity to help save our salmon and secure a just and prosperous future for everyone in the Columbia Basin," Takala said. "First, for clarity, the Yakama Nation is not a radical environmental special interest group."

Its rights to salmon from the rivers are guaranteed by the treaty the tribe signed with the federal government in 1855, he added.

"Since time immemorial, the strength of our Yakama Nation and its people have come from the Nch'í-Wána — 'the big river,' or the Columbia River — and its tributaries and from the fish, game, roots and berries nourished by their waters," Takala said. ■

CAISO/West News

BPA Targets August for Draft Day-ahead Market Decision

Final Decision Slated for November; April Policy Letter to Include Market 'Leaning'

By Robert Mullin

The *Bonneville Power Administration* plans to issue a draft decision on its day-ahead market participation in August, followed by a final decision in November, the federal power marketing agency told stakeholders Feb. 1.

The new timeline represents a shift from the one BPA initially set out last July when it launched a series of workshops to explore its potential participation in either CAISO's Extended Day-Ahead Market (EDAM) or SPP's Markets+ offering.

At that time, the agency had targeted February 2024 for the release of a "policy direction" including a decision on whether to join any day-ahead market and a "leaning" on which of the markets it would likely choose.

While the exact meanings of "policy direction" and "leaning" have been open questions for months, the expected content of both became somewhat clearer last week.

BPA told stakeholders during its Feb. 1 day-ahead markets (DAM) workshop that it now plans to issue a "policy letter" in early April that will provide a "light touch" on the agency's business case and legal authority to participate in a day-ahead market.

The letter also will contain a "description of BPA's strategic vision related to DAMs, including a staff recommendation on whether to pursue participation and which DAM may be the best fit for BPA at this time," BPA said.

In an emailed response to questions from *RTO Insider*, BPA spokesperson Doug Johnson said the letter "will provide a staff recommendation with an initial policy direction as to whether BPA sees value in joining a day-ahead market and, if so, which DAM option best meets its principles. BPA will include a brief description of its legal authority to participate, an initial evaluation of the value proposition and a discussion of other factors supporting its staff leaning."

BPA's revised timeline now calls for the release of a "draft policy" on day-ahead market participation at the end of August, which will cover the agency's business case and legal authority regarding participation. The draft will also "either validate BPA's initial staff recommendation" on a market choice or "lay out an alternative direction," the agency said.

BPA's Bonneville Dam | *U.S. Fish and Wildlife Service*

BPA has tentatively scheduled a public workshop on the draft policy for Sept. 19. It then plans to issue a final policy and record of decision in November.

In the meantime, the agency said it will continue to engage with stakeholders on the day-ahead market issue. Another DAM workshop will be held in the first week of May to discuss the April policy letter, the staff recommendation and any comments received by the agency. Additional workshops are scheduled for June 5 and Aug. 6.

Competing Concerns

The change in BPA's timeline comes in response to the tangle of issues the agency confronts as it moves toward a decision.

One of the thorniest relates to BPA's "preference customers," made up of publicly owned utilities across the Northwest, who are concerned that the agency's deeper involvement in an organized market could compromise their rights to access low-cost power from the federal Columbia River hydroelectric system. They are seeking greater guarantees that protect their interests before BPA decides to join any day-ahead market.

Another key issue relates to BPA's choice of a market as *CAISO* and *SPP* compete for participants in their respective day-ahead offerings. BPA's decision carries significant weight because it operates about 70% of the transmission in the Northwest and is the region's largest power provider.

It's for that reason the agency has been under significant pressure on multiple fronts to slow down its decision-making process.

At BPA's second DAM workshop last September, stakeholders who support a single market for the West based on CAISO's platform complained that the agency's initial timeline was too aggressive. They were concerned BPA's leaning effectively would constitute a final decision — and that the agency already was favoring Markets+.

Key critics of the faster timeline include the environmental and consumer group Northwest Energy Coalition, as well as state energy officials from Oregon and Washington. They contend BPA should delay issuing a leaning until developments play out around the *West-Wide Governance Pathways Initiative*, a state-led effort to create the framework for an independent Western RTO that includes CAISO while addressing concerns about the ISO's governance. In comments filed with BPA in November, municipal utility Seattle City Light questioned why the agency was not directly participating in the initiative given that it was designed to address many of BPA's concerns related to CAISO governance.

Others, including some public power representatives, have said a quick decision was necessary to ensure the agency exercised sufficient clout to shape market developments in the broader West. (See *NW Stakeholders Divided on BPA Timeline for Day-ahead Decision*.)

BPA appeared to be touching the brakes on a decision during its November DAM workshop, when it told stakeholders it still would issue a policy direction during the first quarter of 2024, but that the content would change to cover the agency's statutory authority to join a day-ahead market while also including a market leaning.

During that meeting, Russ Mantifel, BPA director of market initiatives, acknowledged the agency still had "limited information" on which to base a market decision, saying the timing was "up in the air" in light of uncertainties around tariff timelines for EDAM and Markets+. (See *Region Still Split as BPA Approaches Day-ahead Market Decision*.)

Since then, *FERC* has approved CAISO's EDAM tariff and SPP has pushed back the schedule of its Markets+ tariff filing from early February. The Arkansas-based RTO now plans to put the tariff to a board vote in late March and hopes to win FERC approval within nine months, which then would allow the RTO to begin Phase II of the market's development. (See *SPP Markets+ Participants Executive Committee Briefs: Jan. 23-24, 2024*.)

'Sufficient Information'

BPA on Feb. 1 rebuffed concerns by Oregon and Washington state agencies that the agency still lacks the information needed to support a leaning. In a slide presented during the workshop, the agency affirmed that it "will issue its initial staff recommendation regarding Bonneville's policy direction on potential DAM participation in a letter this spring and feels it has sufficient information to do so."

BPA told *RTO Insider* the staff recommendation "will inform customers and stakeholders about its policy leaning to aid in their assessments of the changing energy landscape, provide considerations regarding potential DAM participation, inform customer product choices and operational goals, and invite discussion on other salient issues that BPA should consider when developing a more formal policy direction and issuing a record of decision in late 2024.

"Any decision to join a DAM would be dependent on BPA rate and tariff proceedings and contract updates," it said.

BPA said it continues to monitor developments taking shape across the West, including efforts around the Pathways Initiative.

"BPA staff have been assessing CAISO's EDAM and SPP's Market+ day-ahead market designs, public power concerns and support regarding potential participation, and considerations regarding issues such as carbon emissions reduction goals, continuing to meet environment, fish and wildlife stewardship obligations, maintaining close relationships with states and tribes, and providing service in the most economical, efficient and reliable manner," Johnson said. "BPA has interfaced with other potential DAM participants to understand potential market footprints." ■

CAISO/West News

NM Utilities to Pursue More Analysis Before Day-ahead Decision

PNM, El Paso Electric, Regulator Review Results of Key Market Benefits Study

By Elaine Goodman

Two New Mexico utilities said they need to conduct more analysis before they make a choice between competing day-ahead markets in the West, despite the results from a key study on the financial impacts.

The comments from representatives of Public Service Company of New Mexico (PNM) and El Paso Electric (EPE) came during a Jan. 25 workshop hosted by the New Mexico Public Regulation Commission.

The focus of the workshop was a cost-benefit study conducted for the Western Markets Exploratory Group (WMEG) by Energy+Environmental Economics (E3).

E3 analyzed two different footprints across the West for participation in either CAISO's Extended Day-Ahead Market (EDAM) or SPP's Markets+. The study examined production costs under two different market participation footprints as compared to a business-as-usual scenario.

EDAM and Markets+ are both expected to launch in 2026, and potential participants are scrambling to understand what choice would be best.

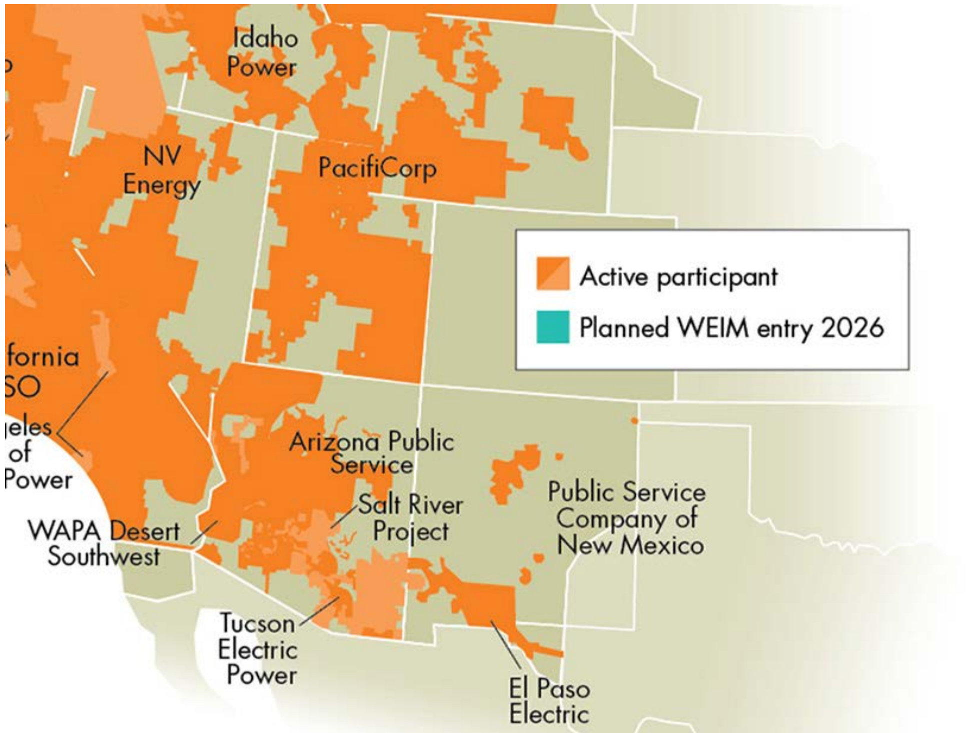
Emmanuel Villalobos, director of market development and resource strategy at EPE, said the utility is planning "very involved, robust studies" as a follow-up to the WMEG analysis.

The next step will be to layer onto the WMEG study real-world operational constraints and resource adequacy considerations, he said. That work, expected to take place this year, will be followed by a gap analysis. EPE expects to choose a day-ahead market in 2025.

Kelsey Martinez, PNM's director of regional markets and transmission strategy, said in a previous PRC workshop that the footprint of each day-ahead market would be a major deciding factor — a point she reiterated during the latest workshop. (See *New Mexico Contemplates Organized Market Choice*.)

"The market footprint is a key factor in determining the realization of a lot of the benefits that come with day-ahead market participation,' Martinez said. "So [are] the production and trade benefits, the resource diversity and increased reliability as well."

Martinez called the WMEG study "one tool in our toolbox." She said PNM is gathering information on each market's rules for third-party transmission usage and the rules' impact on PNM benefits.



The WMEG studies for Western Energy Imbalance Market members PNM and EPE examined the impact of the utilities becoming an "EDAM island" if Arizona's utilities decided to join SPP's Markets+. | *CAISO*

Another issue, she said, is the likelihood that either market will evolve into an RTO, which PNM strongly supports.

Martinez said PNM is closely following the West-Wide Governance Pathways Initiative for changes that might allow "wider adoption of the CAISO markets and evolution of those markets." (See *Western RTO Initiative Outlines Governance Options*.)

Footprint Analysis

The workshop was part of the PRC's effort to develop guiding principles for utilities when deciding whether to join a day-ahead market or RTO. (See *NM Commission to Set Standards for RTO, Day-ahead Participation*.) Additional workshops on the topic are possible.

During the workshop, Jack Moore of E3 gave an overview of the WMEG cost-benefit study. E3 has presented the findings previously. (See *Study Shows Uneven Benefits for Calif., Rest of West in Single Market*.)

One of the two footprints evaluated was the EDAM Bookend, a single combined day-ahead and real-time market covering the entire Western Interconnection except for British Columbia and Alberta.

Under the EDAM Bookend, the West as a whole would save $60 million a year compared with a business-as-usual case — although results varied among individual balancing area authorities.

The second scenario is called a Main Split footprint, in which most of the West would participate in Markets+, but CAISO, PacifiCorp, Los Angeles Department of Water and Power, Balancing Authority of Northern California, Turlock Irrigation District and Imperial Irrigation District would join EDAM.

In the Main Split, West-wide costs would rise by $221 million relative to business as usual. Results again varied by agency.

'EDAM Island'

PNM and EPE asked E3 to analyze an additional scenario similar to the main split footprint, but in which New Mexico goes with EDAM rather than Markets+. This would create a

CAISO/West News

"New Mexico EDAM island," with neighboring Arizona in Markets+. The scenario is just a "what if," E3 said, and not an indication of which market the states will ultimately join.

In the EDAM Island scenario, a New Mexico-California transaction might face wheeling charges between New Mexico and Arizona, and again from Arizona to California. The impacts could potentially be reduced if transmission arrangements or market-to-market coordination agreements were in place, E3 said, but such agreements weren't included in the modeling.

E3's analysis found that PNM would see a $41 million cost increase in the EDAM Island scenario compared with business as usual, excluding wheeling revenue. PNM was modeled as being a "heavy exporter" of low-cost wind and solar resources.

For EPE, costs would decrease by $23 million in the EDAM Island scenario, as the utility would be able to buy energy from the PNM zone at lower prices.

WEIM Impacts

PNM and EPE are both participants in CAISO's Western Energy Imbalance Market (WEIM), a regional real-time energy market.

Martinez of PNM noted that selection of a day-ahead market would be "bundled" with participation in a real-time market. So if PNM decided to join Markets+, the utility would leave WEIM and instead enter SPP's real-time market.

From the time it was launched in 2014 through the end of 2023, WEIM participants achieved $5 billion in benefits, including $392 million in benefits in the fourth quarter of 2023 among its 22 participants, CAISO *reported* Jan. 31.

Fourth-quarter benefits were $6.1 million for PNM and $4 million for EPE.

During the workshop, Vijay Satyal, deputy director of regional markets for Western Resource Advocates, asked whether the analysis of the Main Split scenario considered the impact of PNM and EPE leaving WEIM if they joined Markets+.

"Was that potential loss of benefits factored into the net total cost impact?" he said.

Moore said the study accounted for those factors.

Michael Barrio, a senior principal with Advanced Energy United, pointed to what the group considers to be limitations of the WMEG study.

"The study focuses narrowly on operational costs, failing to account for broader benefits, like reliability, capacity savings and resource diversity, which could be much larger," Barrio said during the workshop.

Despite all the effort going into choosing a day-ahead market offering, Martinez of PNM noted that the barrier for leaving either market will not be high.

"If there are major topological changes or generation changes or market footprint changes, that could very easily trigger another benefit analysis from us, and we could shift to a different market operator," she said. ■

CAISO/West News

Western Market Seams Issues to Differ from East, Study Finds

Region's Day-ahead Markets Face Different Challenges from Eastern RTOs

By Robert Mullin

A new study finds that the seams dividing CAISO's Extended Day-Ahead Market (EDAM) from SPP's Markets+ in the West would pose a different set of problems than challenges seen at the boundaries of full RTOs in other parts of the U.S.

The Seams Evaluation *study* was commissioned by the Western Power Trading Forum (WPTF) and Public Generating Pool (PGP) and prepared by Energy Strategies and Gridwell Consulting.

The study seeks "to provide a framework for understanding the key seams areas and seams issues that may exist between the two proposed day-ahead markets in the West," while not taking a position on whether the region should have one or two day-ahead markets.

The authors also said they did not intend "to propose specific solutions to seams issues" or provide a comprehensive assessment of all potential issues.

The study lays out how the two day-ahead markets proposed for the West are "fundamentally different" from RTOs in the East.

Those differences include the fact that, unlike the day-ahead markets, the RTOs feature the consolidation of balancing authorities and full participation of entities within the BAs; fully coordinated resource adequacy; and consolidation of transmission planning and generator interconnection to the grid.

The day-ahead markets also would lack full co-optimization of energy deliveries and ancillary services and would require consolidation of open-access transmission tariffs to completely optimize use of transmission.

Seams Within Seams

A key challenge Western day-ahead markets likely would share with Eastern RTOs is the issue of "economic" seams, which arise when boundaries between markets hinder the most cost-effective dispatch of energy across the grid and prevent operators from managing transmission congestion to the greatest extent possible.

To mitigate the impact of economic seams, neighboring RTOs use interface pricing to help facilitate energy flows between them in both the day-ahead and real-time market. The study points out that RTOs also address their boundaries with additional tools, such as interchange scheduling, day-ahead firm flow entitlement exchange, coordinated transaction scheduling and market-to-market coordination.

"While the West should be able to build on these concepts, these tools are currently untested under the non-RTO day-ahead market frameworks and may not translate directly given the seams within the day-ahead markets," the study says.

The authors note that the mechanisms RTOs use to manage economic seams are the result of negotiations, agreements and joint design efforts among stakeholders from both markets.

"Additionally, given the nature of day-ahead markets, we expect that there will be more parties and/or more seams agreements required (including between BAs and Market Operators) than is seen in the context of Eastern RTOs," the study says.

The study also delves into the challenges likely presented by seams within Western day-ahead markets as well as between them. Key among them is that both EDAM and Markets+ lack mechanisms for co-optimizing awards for ancillary services with day-ahead energy, although the study acknowledges that could change in the future.

Another internal seam stems from the fact that both day-ahead markets as proposed will allow their BAs to continue to use existing constraints to ensure that market participation doesn't compromise their reliability obligations, effectively allowing for voluntary participation in the markets.

"This may affect the extent to which BAs rely on the market for imports and commit units within their own footprint, which can reduce overall benefits through lack of full optimization of the fleet," the study finds.

Another key internal barrier will be the lack of a common resource adequacy framework. Participants in both EDAM and Markets+ will have the option of either joining the Western Power Pool's Western Resource Adequacy Program or not committing to any RA program at all, while California utilities will continue to be subject to that state's RA requirements.

"Given the lack of a consistent RA and full [must-offer obligation], other mechanisms must be designed to address sufficiency of resources by individual market participants or BAs in a day-ahead market," the study says.

Western Challenges

The study also explores potential seams issues specific to day-ahead markets in the West, including increased barriers to contracting for resources, with the boundary between the markets possibly introducing new complexities to contracts, raising costs and increasing risks around deliveries.

Greenhouse gas accounting and dispatch inefficiencies would represent another key barrier between the two markets, according to the study. These would "result from the absence of a single day-ahead market to produce coordinated GHG pricing signals and establishment of similar treatment to all imports into GHG-regulated areas, even under linked carbon pricing programs," the study says. California and Washington currently operate under separate GHG cap-and-trade programs, but efforts are underway to link them within the next couple of years.

Different approaches to market power mitigation could create yet another type of seam between Western markets, the study finds. The authors point to the increased potential for "higher instances of uncompetitive conditions due to optimizing over two smaller footprints as opposed to one larger footprint."

They also caution that Markets+ is in the process of developing a balancing authority area-level mitigation system that could differ from what CAISO already has in place for the Western Energy Imbalance Market.

"Creation of two ways to address system/BAA-level market power mitigation will naturally result in areas being exposed to differing levels of over- and/or undermitigation," the study said, noting that the differences could result in differing levels of contracting for resource among the markets.

The WPTF/PGP study should contribute to discussions about day-ahead market seams already taking shape in the West. At a recent meeting of the Markets+ Participants Executive Committee, supporters of both markets spoke about the need to begin addressing the reality of a divided region. (See *SPP Markets+ Participants Executive Committee Briefs: Jan. 23-24, 2024*.)

WPTF and PGP will host a webinar to discuss the seams study today. ■

CAISO/West News

Group Looks to Create 'Actionable' West-wide Transmission Plan

WestTEC to Prioritize Big Picture, Inclusivity to Spur Interregional Projects

By Robert Mullin

Backers of the recently formed Western Transmission Expansion Coalition want to fill a void in the Western Interconnection by producing an "actionable" interregional transmission study — one that starts with a holistic view of the region's needs.

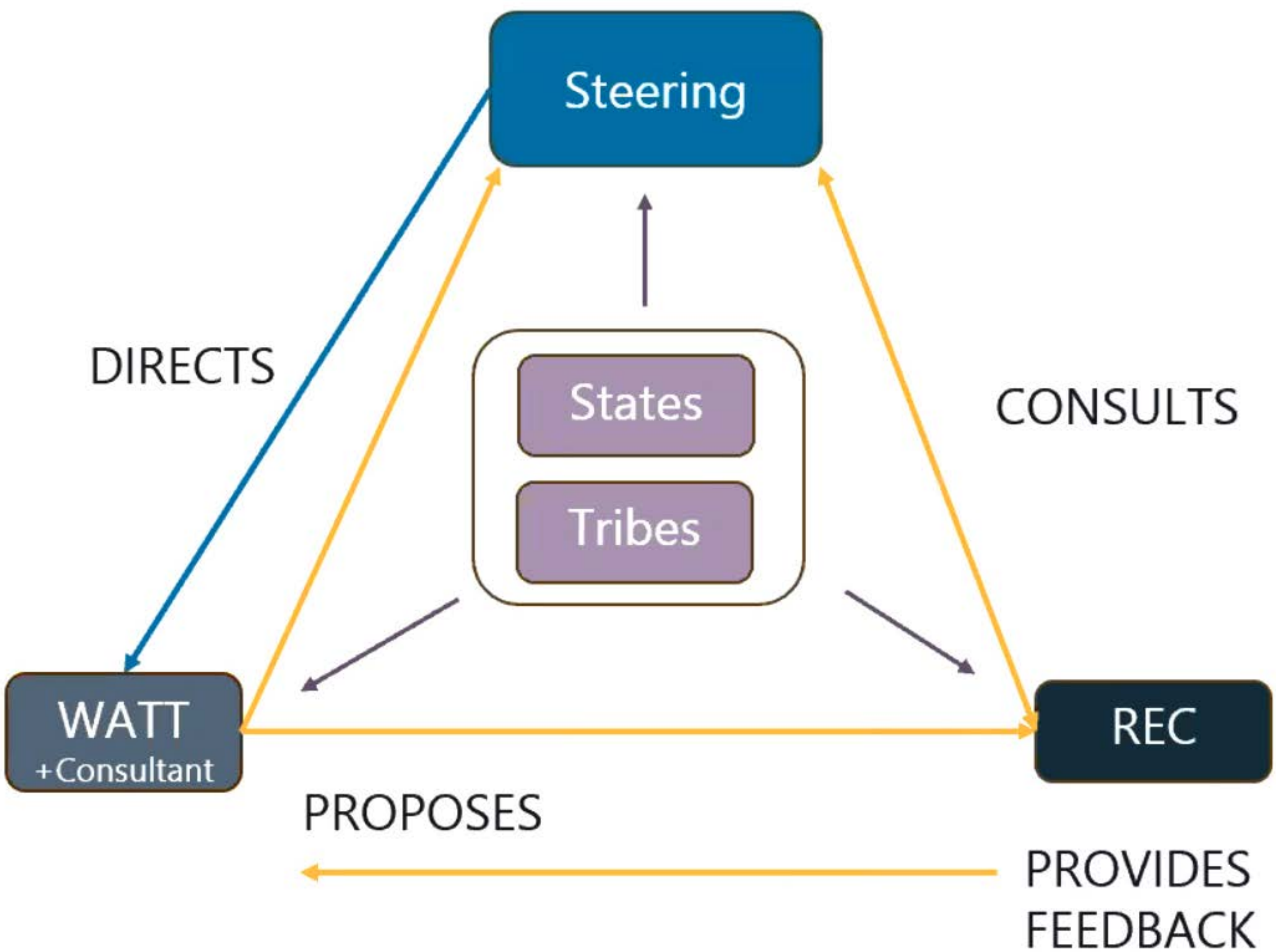
"The idea here is that we're looking at that entire collective footprint, and not just the subregions," Sarah Edmonds, CEO of the Western Power Pool (WPP), said during a Jan. 29 call to update stakeholders on the WestTEC effort, which was launched last October. (See *Plan Seeks to Boost Prospects for New Transmission in the West*.)

Edmonds explained the meaning of "actionable."

"We want to provide high-confidence information to the industry so that if there are parties who are interested in advancing transmission build solutions, they can take the information out of our study, knowing that the study has a high-confidence factor built by all of the different participants," including states and tribes, she said.

Edmonds reaffirmed that WestTEC won't try to tackle the especially thorny subjects of transmission cost allocation, siting and permitting, despite the wishes of some stakeholders who provided comments on the effort's *concept paper*. (See *Western Transmission Initiatives Differ on Dealing with Cost Allocation*.)

"We don't deny that cost allocation, permitting and siting are complicated matters and that, in many ways, this study is the easiest part of



WestTEC backers are proposing an organizational structure that includes a Steering Committee to oversee the effort, a WestTec Assessment Technical Team (WATT) to dig into data and details, and a Regional Engagement Committee (REC) to bring policymakers and other stakeholders into the process. | *WestTEC*

CAISO/West News

a journey towards transmission solutions," she said. "So when we say 'high confidence,' we're really hoping that the study itself will really grease the skids for future conversations around all of those things."

Former FERC Chair Richard Glick, now a principal at GQ Energy Strategies and a consultant for WestTEC, spoke on the call, emphasizing the need to stay focused on the planning end of transmission development.

He pointed to the region's growing concerns around resource adequacy, rising demand from electrification and increasing instances — and "ferocity" — of extreme weather events. Glick noted also that the Department of Energy's most recent *National Transmission Needs Study* noted that the Northwest and Southwest could require an additional 30% of transmission capacity by 2035.

"As I think most people have seen, there's been some frustration that the current approach to regional transmission planning in the West — particularly outside of the California ISO — has not been very effective," he said.

Issues of cost allocation and siting are being picked up elsewhere, Glick said. Western state officials have started moving to address regional transmission cost allocation, as evidenced by the state-led Western States Transmission Initiative.

And given the scale of federal ownership of land in the West, siting and permitting are being addressed at the federal level.

"I know the Department of Energy now is taking the lead in terms of being the lead siting agency at the federal government," Glick said. "There's a number of bills pending in Congress right now that would attempt to facilitate and improve the transmission siting environment that currently exists."

'Biggest Tent Possible'

Inclusivity was a key theme during the call.

"WestTEC is about expanded engagement," Edmonds said, noting the organization has sought to become West-wide and move beyond the participation of just transmission-owning utilities.

Ben Fitch-Fleischmann, director of markets and transmission at the Interwest Energy Alliance, lauded WestTEC for providing a seat at the table for trade associations such as his. He noted the group's roster already includes utilities, independent power producers, the region's three transmission planning entities, National Laboratories, state agencies, tribal representatives and the Western Interstate Energy Board.

"So aiming to pitch the biggest tent as possible," Fitch-Fleischmann said.

WestTEC will seek to prioritize inclusivity through its proposed governance and committee structure, which would include the Steering Committee, Regional Engagement Committee (REC) and WestTEC Assessment Technical Team (WATT).

The Steering Committee, which will oversee the effort, will be "substantially West-wide in its representation," Edmonds said. The committee will include representatives from transmission-owning utilities from across the West, the region's three planning groups — CAISO, NorthernGrid and WestConnect — and WECC.

The REC would seek "a broad membership to make sure we're aligned with state policy and consumer interests," according to Fitch-Fleischmann. Its job will be to review the work of the WATT, gain insights from the region and provide feedback.

"We need to ensure we get timely input from a wide range of governmental agencies, public interest perspectives and the like to make sure we can engage with the broader public," he said.

The WATT will be charged with getting into the weeds around the study.

"This is not a committee where we're looking for another warm body," said Chelsea Loomis, WPP manager of regional transmission planning services. "We need people who can really hit the road and contribute with data that will support the study scope. We need to make sure that we are developing the scenarios that support the execution of that study scope. This will be a very busy group."

Members of the WATT also recently selected consultants to assist in modeling for the study: Energy Strategies, with support from Energy+Environmental Economics.

WestTEC is seeking funding to support its work, just like another big effort taking shape in the Western electricity sector: the West-Wide Governance Pathways Initiative. Edmonds said WestTEC recently completed an application for a DOE grant that seems "tailor made" for its work.

"But I really want to emphasize that it is not a condition for us moving forward," she said. "We're going to find a way to fund this amongst ourselves, and if DOE funding comes along, that will be very helpful. But we're not waiting around for that determination." ■

CAISO/West News

Long-duration Storage Key to Calif. Energy Goals, Report Says

CEC Study Finds LDES Cost-effective for Decarbonizing Grid

By Ayla Burnett

Long-duration energy storage (LDES) will play an essential role in cost-effectively decarbonizing California's electricity grid, according to a report released by the state's Energy Commission (CEC) Jan. 29.

The *study*, prepared by researchers from Energy+Environmental Economics (E3), Form Energy and University of California, San Diego, explores how LDES can help California meet goals set out in Senate Bill 100, the 2018 law requiring the state to serve all retail electricity load with emissions-free power by 2045.

Relying on modeling of the CAISO grid, it represents the most in-depth analysis to date of the crucial role the technology will play in California's transition to renewable energy.

The report also examines LDES's ability to reduce air pollution in the Los Angeles Basin, as well as its role in supporting resilience in microgrids.

Main Findings

The study found that California has made significant progress in its energy transition, with prior studies showing the electric sector could reach 80% or greater decarbonization with existing technologies. But achieving decarbonization and reliability won't be cheap without innovations in LDES, which could be a viable replacement for the natural gas-fired power plants that are traditionally relied upon for dispatchable capacity to balance renewables and meet grid reliability standards.

Under a business-as-usual SB 100 scenario, which allows for retainment of all existing gas resources, the study found that deploying 5 GW of LDES could cost-effectively bring CO2 emissions down to 12 million metric tons by 2045. LDES is far more cost-effective with up to 37 GW deployed by 2045 under a zero-emissions scenario that covers in-state emissions and electricity imports.

Simulations across 35 historic weather years in the Los Angeles Basin case study showed that LDES enables retirement of gas plants in the CAISO system while maintaining reliable grid operation. By 2045, 21 GW of LDES could substitute for all of California's existing gas plant capacity. Without LDES, the study found that the cost of using other resources to avoid reliance on gas plants increases by up to 87%.

"Portfolios that retire in-state gas by using LDES were found to achieve cost parity, and in some cases cost savings, relative to those that retain existing in-state gas," the study found.

While researchers highlighted that further analysis is needed to evaluate the environmental justice benefits of retiring gas-fueled generation more quickly, they demonstrated that LDES will likely play an important role in cost-effectively maintaining local capacity requirements while reducing the need to rely on emitting resources in disadvantaged communities.

"In Form's study of the Los Angeles Basin as an example area, 2 GW of LDES and 1.3 GW of 4-hour lithium-ion storage is found to be the least-cost substitute for gas power plants located in disadvantaged communities, lowering system costs by 3%," Form Energy said in a *brief* about the report. "This is the first time that the benefits of LDES to local reliability and environmental justice have been studied in the state, creating a model for how other local reliability areas can be studied in the future."

Support for Microgrids

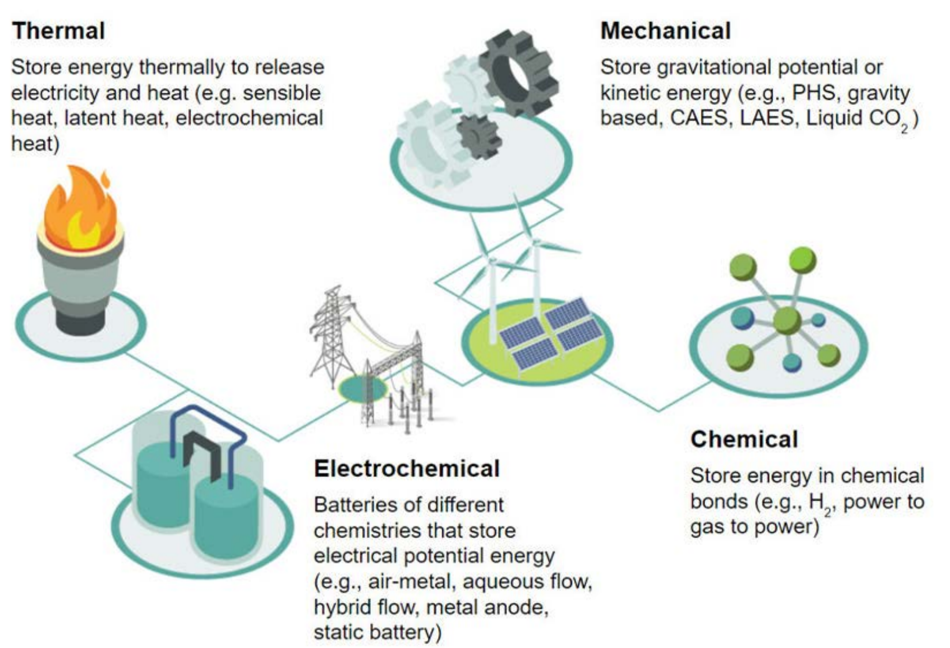
In a case study of microgrids at the University of California, San Diego, the team also found that LDES can support high-reliability microgrids by pairing with other distributed energy resources to deliver 48-hour resilience capability, also known as "islanding," and protecting against outages.

However, LDES-supported microgrids may not be cost effective. The study found that the customer value of lost load needed to justify its use ranged between $5-18 kWh for small campus buildings. Some larger buildings, though, demonstrated a negative value of lost load, showing that some microgrids improve reliability while reducing costs.

Goals

In addition to demonstrating the distinct value LDES will bring to California's energy transition, the study highlighted the need for modeling tools and approaches that can continue to accurately capture the value of LDES in future portfolio planning. It also emphasized the importance of optimizing resource needs with hourly time resolution across a full year and in varying weather scenarios.

"By using these methodologies, grid planners can proactively identify resources that electric markets may not yet be fully valuing," Form's brief said. "From there, policy initiatives can be designed to ensure these resources are able to rapidly proliferate and deliver savings to the electric grid." ■



A California Energy Commission report found that long duration energy storage will be crucial to the state's transition to renewable energy. | *LDES Council*

ERCOT News

Texas PUC Closes 1st Phase of Market Overhaul

By Tom Kleckner

Texas regulators last week celebrated the closure of the first phase of their blueprint for reliability reforms to the *ERCOT* grid, cautioning that it's only a first step.

The Public Utility Commission closed two dockets during its Feb. 1 open meeting, *52373* and *53298*. The former encompassed initial revisions to the market design, and the latter covered the development of a firm-fuel supply service.

"The ERCOT grid is more reliable than it's ever been, and getting to this point has been a total team effort," PUC Chair Thomas Gleeson said in a *statement*, thanking ERCOT staff, industry stakeholders and lawmakers. "This doesn't mean we're done improving the grid. We're just closing the book on this first chapter."

A result of legislation passed after the devastating 2021 winter storm, the first phase reforms included two expansions of the PUC's weatherization rules, requirements for generators to secure backup fuel supplies' new consumer protection measures and market changes that focused on price stability and reliability.

In a *memo*, commission staff said modifications to the operating reserve demand curve, emergency response service reforms, and development of fast frequency response service and ERCOT contingency reserve service have been completed.

They recommended new projects be opened for a firm-fuel product and voltage support compensation. Two other projects are in progress: demand response and setting higher performance standards for energy efficiency programs. The PUC already has received approval for three positions to manage the latter project.

Commissioner Jimmy Glotfelty said he supported the voltage-support docket.

"This is becoming more and more an issue as we have more inverter-based resources. This might be an issue that we need to address in the future, and it'd be good to get positions on it."

Meanwhile, several Phase 2 projects already are running full bore.

The commission reacted positively to staff's *suggestion* that the interim value of lost load


Thomas Gleeson chairs his first PUC meeting. | *Admin Monitor*

(VoLL) that will be used in ERCOT's reliability standard be set at $25,000/MWh and that any study using the metric as an input conduct sensitivity analysis, varying VoLL between $20,000/MWh and $70,000/MWh (*55837*).

VoLL was reduced to $5,000/MWh from $9,000/MWh and decoupled from the system-wide offer cap after high prices during the winter storm. According to the grid operator's market monitor, the $9,000 cap resulted in $16 billion of incorrectly priced market transactions during the storm. Staff noted that *Potomac Economics* said in its 2022 state-of-the-market *report* that the $5,000 value "likely underestimates VoLL by a substantial amount."

Staff carefully reiterated the interim VoLL value is for study purposes only and will not affect consumers' cost of electricity. *The Brattle Group* is beginning a survey of ERCOT retail customers in March to determine their value of lost load. (See "VoLL Study to Begin," *Texas PUC Sends ESR Change back to ERCOT*.)

Staff also presented a draft *scoping document* for a review of ancillary services, as required under the *Public Utility Regulatory Act*. The review's report, a collaborative effort with ERCOT and Potomac Economics, is due to the PUC in September (*55845*).

Protocol Changes Approved

The commission also approved nine protocol changes approved by ERCOT's Board of Directors, but not before probing one revision (*NPRR1181*) that requires qualified scheduling entities to notify the grid operator when inventories drop to critical levels (*55445*).

"These are things that ERCOT wants to know, but these are not critical for market operations," Glotfelty said. "It's the individual generator's responsibility to know how much coal they have, how much energy they have. ... I think this is kind of an overreach, quite frankly."

Dan Woodfin, ERCOT's vice president of system operations, agreed the NPRR isn't needed for market operations. He reminded commissioners that as the region's reliability coordinator, the grid operator needs situational awareness of future reliability risks.

"If we've got a plant that has coal, they're running out of coal or maybe some rail issue or something, we shouldn't be approving transmission outages that depend on one or more of those units at that plant being available," he said. "That's something where that information is critical to us to be able to make good decisions and avoid reliability problems."

Gleeson Chairs 1st Meeting

The meeting marked Gleeson's first as PUC chair. He was appointed to the position by Gov. Greg Abbott (R) last month. (See *Abbott Names PUC Executive Director as Chair*.)

"I've spent almost my entire professional career at this agency. I'll be honest, when I started here 15 years ago, this was definitely not something I saw in my career plan," he said.

Gleeson had been the PUC's executive director since December 2020. He replaces Kathleen Jackson, who was named interim chair when Peter Lake resigned last June.

"We're proud to have you up here with us," Glotfelty said. "We're excited to see you move from representing the entirety of the staff to representing the entirety of all of the people in the state, and we know you'll do a great job each and every way."

"It's quite the transition to having about four people in my office to 240 people," Gleeson said.

Following a brief executive session, the commissioners approved the appointment of Connie Corona, the PUC's deputy executive director, as *interim executive director*. Corona first joined the commission in 1997, returning in 2017 after a 14-year stint in NRG Energy's regulatory affairs group.

The commissioners also agreed to request the state legislative board set their salaries at $225,000 for the remainder of the 2024 fiscal year and at $230,000 for 2025. The request will include setting the executive director's salary at $245,559 for the remainder of 2024 and $257,858 for the 2025 fiscal year. ■

ERCOT News

Texas Supremes Hear Arguments Over Uri's Prices

Review of PUC's Authority to Order Noncompetitive Actions

By Tom Kleckner

The Texas Supreme Court heard oral arguments Jan. 30 over whether the state's Public Utility Commission had the authority to order electric prices be set at $9,000/MWh during the 2021 winter storm or whether billions of dollars in market transactions need to be repriced (*23-0231*).

Attorneys for the PUC and several market participants *said* state rules make it clear the commission's top priority is the Texas grid's reliability. Legal counsel for Luminant, the state's largest generator, *countered* that the PUC exceeded its authority with the emergency pricing order.

When the PUC issued its directive to ERCOT on Feb. 15, 2021, as generation was dropping off during the storm, the grid operator's algorithm was setting prices as low as $1,200/MWh. Under ERCOT's market construct, prices are designed to increase during scarce conditions to incentivize more generation to come online.

The problem was, there wasn't enough generation during the first two days of the storm because of frozen equipment or lack of fuel supplies. ERCOT kept prices at the $9,000 cap — since reduced to $5,000 — until Feb. 19, resorting to rolling blackouts to keep the grid stabilized.

"Is it really your position that [the PUC's commissioners] are tied to the mast of competition in a way that prevents them from taking that action, if we are in a world where it actually is the case that they just have to commandeer the market for a while to make sure we're not in the Stone Ages for a few weeks?" Justice Jimmy Blacklock asked Gibson, Dunn & Crutcher partner Allyson Ho, who represented Luminant.

Ho said the state's *Public Utility Regulatory Act* prohibited the commission from setting prices by "regulatory fiat."

"The agency did the one thing that the [Texas] Legislature expressly said it could not do, and that is set prices," Ho said.

Earlier this year, Texas lawmakers attempted to fix the loophole with *House Bill 1500*. The legislation includes a section that requires the commission to issue a written order when directing ERCOT to take certain actions.

Lanora Pettit, a lawyer with the Texas Attorney General's office, said "the authority existed at the time" to order ERCOT to raise prices in trying to stabilize the grid. She said the PUC's message to ERCOT was "that your algorithm's not working the way it's supposed to, so please go fix it and get in line with the rules we've already established."

"The understanding of everybody in the market was that [$9,000/MWh] was the price that when load was being lost, that would be charged," Pettit said. "What happened here was not an amendment to that rule, but instead of direction to ERCOT."

Ho responded for Luminant, saying the order did little to bring more generation online because all plants that could run in the frigid conditions already were doing so.

Luminant initiated the proceeding after it incurred $1.6 billion in losses when forced to buy backup power at the system cap and gas supplies at equally exorbitant prices. (See *Vistra's Winter Storm Loss Deepens to $1.6B*.)

The company won a surprise judgment from the 3rd Court of Appeals in March when it reversed the PUC's emergency orders. The court found the commission's actions "entirely" eliminated competition and were contrary to state law. (See *Texas Court Reverses PUC's Uri Market Orders*.)

The state Supreme Court in September agreed to review the appeals court's ruling. (See *Texas High Court to Review Decision on Uri Charges*.)

The emergency order resulted in $16 billion of market transactions that ERCOT's Independent Market Monitor said were incorrectly priced during the 33 hours that followed the end of firm load shed. The PUC declined to reprice the transactions. (See "Monitor: $16B ERCOT Overcharge," *ERCOT Board Cuts Ties with Magness*.)

Some of the $16 billion balance has since been securitized, and some participants have been paying off debts they now might not even owe. Other transactions have been settled outside ERCOT and can't be undone, according to legal experts.

Two of the Supreme Court's justices recused themselves from the proceeding. A third was absent. A decision is not expected to be rendered for several months, but the high court normally issues judgments on all proceedings it takes up. Its current term ends June 28. ■

The Texas Supreme Court hears oral arguments over ERCOT's high prices during the 2021 winter storm. | *The Supreme Court of Texas*

ERCOT News

ERCOT Technical Advisory Committee Briefs


ERCOT's Technical Advisory Committee begins its January meeting. | *ERCOT*

Stakeholders Continue Discussion of IBR Reliability Requirements

ERCOT stakeholders last month moved closer to taking action on a tabled rule change that would address the reliability concerns with inverter-based resources (IBRs).

Staff told the Technical Advisory Committee during its Jan. 24 meeting that the prevalence of IBRs on the system has increased the likelihood of potential instability issues, such as the recent Odessa disturbances. They said the issues are only going to increase along with the continued growth of solar and wind resources. (See *NERC Repeats IBR Warnings After Second Odessa Event*.)

ERCOT says the Nodal Operating Guide revision request (*NOGRR245*) would improve the clarity and specificity of IBRs' voltage ride-through requirements. The NOGRR would align the grid operator's rules with NERC reliability guidelines and the most relevant parts of the Institute of Electrical and Electronics Engineers *standard* for IBRs interconnecting with the grid.

FERC also recently issued Order 901, directing NERC to address same risks NOGRR245 takes on.

ERCOT has recommended that TAC approve the change with recent comments it *filed*. It said a recommended proposal by the committee's Reliability and Operations Subcommittee is not acceptable, as it does not address the current "significant reliability risk."

Staff have made several changes to the proposed NOGRR to allow for additional exceptions for documented technical limits. IBRs must:

- meet existing requirements and "substantially" meet new requirements, with each plant's documented technical limit level becoming the requirement for that plant;
- maximize capability through software upgrades and minor hardware upgrade kits;
- accurately represent technical limits in all provided models; and
- meet the latest requirements upon repowering, retrofitting or reinvestment.

They also cannot create any instability, uncontrolled separation or cascading outages for the ERCOT grid.

TAC agreed to resume discussion of the NOGRR at its next meeting, which it rescheduled from Feb. 27 to Feb. 14. The virtual meeting is designed to give stakeholders an opportunity to endorse a recommendation for the Board of Directors' Feb. 26-27 meetings.

RUC Use Down Sharply

ERCOT saw a "significant" decrease in reliability unit commitments (RUCs) last year compared to the previous two years, staff told stakeholders.

The grid operator had 2,726 instructed resource-hours resulting in 2,500.6 effective hours. In 2022, ERCOT saw 8,244.8 instructed resource-hours and 7,910.5 effective hours; in 2021, effective resource-hours came in at 3,853.1. (See "RUCs Continue to Increase," *ERCOT Technical Advisory Committee Briefs: Jan. 24, 2023*.)

ERCOT bought back 509.5 effective resource-hours, a 20.4% rate that matched 2022's buyback.

Ryan King, manager of market design, said changes in resource owners' real-time price expectations and higher demand were among the factors contributing to RUCs' reduction. While reluctant to identify specific causes for the decrease, he admitted the deployment of ERCOT contingency reserve service in June and higher ancillary service requirements since the 2021 winter storm may have played a role.

"Some of these factors might have been present all the time, and all of these might have been present some of the time, but I'm not sure that we have a really definitive cause and effect," King told TAC.

He said ERCOT will continue to monitor and report on factors contributing to commitment changes.

The grid operator incurred $3.67 million in RUC make-whole payments, almost exclusively covered through capacity-short charges, last year, along with $3.45 million in claw-back charges.

ADERs now up to 9

Dave Maggio, ERCOT's market design and analytics principal, said seven aggregated distributed energy resources (ADERs) have been approved to go through the qualification and validation process of commercial operations.

They will join two ADERs that have already qualified to participate in the wholesale electric market; they are providing 9.4 MW of energy and 3.1 MW of non-spinning reserve service since their participation following the

ERCOT News

first phase of a virtual power plant (VPP) pilot project. (See "2 VPPs Qualified for Market Participation After Pilot Project's 1st Year," *Texas Public Utility Commission Briefs: Aug. 24, 2023*.)

The ADERs will participate in the second phase of the VPP pilot. They will be limited to an 80-MW cap for energy and 40 MW for non-spin.

Data related to the ADERs' market participation have been "somewhat limited," Maggio said, but it has still been enough to propose incremental changes for the second phase. Staff plan to present a Phase 1 report and a draft of the Phase 2 governing document to the board and its Reliability and Markets Committee this month.

Jupiter's Smith Elected TAC Chair

TAC members elected Jupiter Power's Caitlin Smith as its chair for the next two years, elevating her from vice chair, the position she's held the past two years. They also elected Oncor's Collin Martin as vice chair. There were no other candidates.

Members also confirmed the leadership of its subcommittees and sub-groups after elections were held within the stakeholder groups last year:

- Protocol Revision Subcommittee: Diana Coleman, CPS Energy, chair; Andy Nguyen, Constellation Energy Generation, vice chair.
- Retail Market Subcommittee: John Schatz, Luminant, chair; Debbie McKeever, Oncor, vice chair.
- Reliability and Operations Subcommittee (ROS): Alexandra Miller, EDF Renewables North America, vice chair.
- Wholesale Market Subcommittee: Eric Blakey, Pedernales Electric Cooperative, chair; Jim Lee, CenterPoint Energy, vice chair.
- Credit Finance Sub-group: Brenden Sager, Austin Energy, chair; Loretto Martin, Reliant Energy Retail Services, vice chair.

Katie Rich was elected as the ROS chair when she was with Golden Spread Electric Cooperative, but she has since changed jobs. A new election will be held at the subcommittee's next meeting.

Tier 1 Project Endorsed

TAC's unanimously approved combination ballot included a Tier 1 transmission project that will go to the board for approval. ERCOT labels projects costing more than $100 million and requiring the directors' approval as Tier 1.

Texas-New Mexico Power submitted the Pecos County Improvement Project last year to ERCOT's Regional Planning Group for its review. The RPG studied nine options before settling on its recommendation to address the reliability need under maintenance outage conditions near Fort Stockton in the Far West weather zone.

The project consists of about 55 miles of new and rebuilt 138-kV transmission lines and a new substation. It has a capital cost of $114.8 million, with the upgrades expected to be completed by August 2026.

The combo ballot included seven nodal protocol revision requests (NPRRs), single changes to the Planning (PGRR) and Retail Market (RMGRR) guides, and a system change request (SCR) that, if approved by the board and the PUC, would:

- *NPRR1170*: define when a qualified scheduling entity (QSE) representing a resource that relies on natural gas as its primary fuel source should notify ERCOT about gas supply disruptions.
- *NPRR1179*: ensure that QSEs representing resources with an executed and enforceable transportation contract procure fuel economically and file a settlement dispute to recover their actual fuel costs incurred when instructed to operate because of an RUC. This change would also adjust the RUC guarantee to reflect the cost difference between the actual fuel consumed during the RUC-committed intervals and the fuel burn calculated based on verifiable cost parameters and would clarify that fuel costs may also include penalties for fuel delivery outside of RUC-committed intervals.
- *NPRR1195*: assign ERCOT-polled settlement metering facilities' maintenance and repair responsibilities to the facilities' owner if it is not a transmission and/or distribution service provider (TDSP).
- *NPRR1206*: clarify the QSEs required to have a hotline and a 24/7 control or operations center, and reconcile the deadline by which QSEs representing resource entities that own or control resources must provide notice that they are terminating their representation and the deadline that resource entities owning or controlling resources to change QSEs with a 45-day timeline.
- *NPRR1207*: permit the incidental disclosure of protected information and ERCOT critical energy infrastructure information (ECEII) during a tour or overlook viewing of the ERCOT control room provided to eligible persons who have signed nondisclosure agreements and complied with screening and other requirements before accessing the control room.

Caitlin Smith, Jupiter Power | *ERCOT*

- *NPRR1208*: create a new daily ERCOT invoice report listing invoices issued for the current day and day prior at a counter-party level.
- *NPRR1211*: incorporate the other binding document "Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints" into the protocols.
- *PGRR109*: require interconnecting entities associated with IBRs to undergo a dynamic model review process before the commissioning date and mandate that resource entities owning or controlling operational IBRs undergo a review process before changing settings or equipment that could affect electrical performance and necessitate dynamic model updates.
- *RMGRR179*: add a communication method so TDSPs can use Texas standard electronic transactions to inform retail electric providers of record which electric service identifiers are affected by a TDSP's mobile generation or temporary emergency electric energy facility deployment.
- *SCR825*: modify ERCOT's current control room voice communication configuration(s) to give QSEs and their subordinate QSEs greater flexibility when assigning agent(s), including allowing sub QSEs to assign agents different from those used by the parent QSE. ■

— Tom Kleckner

ISO-NE News

FERC Approves ISO-NE's Day-Ahead Ancillary Services Initiative

By Jon Lamson

FERC on Jan. 29 approved ISO-NE's proposal to create a day-ahead ancillary services market and retire the current Forward Reserve Market (FRM), effective March 1, 2025 (*ER24-275*).

Dubbed the Day-Ahead Ancillary Services Initiative (DASI), ISO-NE and NEPOOL jointly filed the proposal at the end of October. The new market will procure operating reserves and fill any gaps between the amount of energy procured in the Day-Ahead Energy Market (DAEM) and the load forecast.

"We are pleased with the approval by FERC to create a day-ahead ancillary services market that, together with today's Day-Ahead Energy Market, creates a single, jointly optimized day-ahead market," ISO-NE told *RTO Insider* in a statement.

With climate change increasing weather variability as the resource mix shifts toward weather-dependent resources, DASI will "encourage reliable resource performance and prepare the system on a day-ahead time frame with the flexibility needed to manage these new operational uncertainties," ISO-NE said.

ISO-NE and NEPOOL noted in their *joint filing* that the existing DAEM "only procures energy to meet bid-in demand, and if the load forecast exceeds the amount of cleared energy from physical suppliers, there remains what the ISO refers to as a day-ahead 'energy gap.'"

The RTO currently relies on out-of-market solutions to identify resources to fill these energy gaps and provide operating reserves.

"This process results in both under-compensation to those resources identified to provide these capabilities during the operating day and no specific financial obligation or incentive for such resources to be prepared to perform in real time in accordance with the operating plan," the proposal said.

The ancillary services market will be run in conjunction with the existing DAEM; it will procure 10-minute spinning and non-spinning reserves and 30-minute operating reserves. It will also include an "Energy Imbalance Reserve" product, which is intended to fill energy gaps between the DAEM and the load forecast.

"DASI will provide targeted compensation and clear financial obligations and incentives for the flexible resources on which the region currently relies, and on which it will increasingly rely as the region heads into the future," the filing said.

DASI will replace ISO-NE's FRM, which provides forward seasonal payments for resources to provide 10-minute non-spinning reserves and 30-minute operating reserves. ISO-NE has said the FRM is incompatible with the implementation of DASI.

ISO-NE noted that an analysis of projected DASI revenues based on a 2019-2021 study period found that the initiative would increase annual wholesale market costs by about $104 million, or about 1.1%. The study indicated that the ancillary market would generate "substantial revenues" for storage resources, ISO-NE added.

The joint filing was supported in comments by the New England States Committee on Electricity, the Electric Power Supply Association, the National Hydropower Association and the New England Power Generators Association.

Meanwhile, LS Power *expressed concern* that replacing the FRM with DASI could decrease revenue for flexible resources.

"The overall DASI proposal will cut revenues for flexible generation by as much as 94%," the company wrote in its comments, adding that DASI could introduce "unreasonable and undercompensated risks" for peaking resources.

In response, ISO-NE disputed LS Power's revenue calculations. The RTO noted that its impact assessment found that total net revenues for ancillary service suppliers would decrease by only about $5 million annually, adding that this assessment "may understate the revenues that will be earned by reserve-capable suppliers, compared to those currently earned through the FRM."

The DASI filing requires ISO-NE's Internal Market Monitor "to issue *ad hoc* reports on the competitiveness of any major market design change within one year of the effective date of operation, and on its performance within three years."

The RTO recognized requests from stakeholders for longer-term reserves and wrote that it plans to kick off discussions on longer-term products for the real-time and day-ahead markets in 2025.

FERC found that DASI will "materially improve operating reserve resource readiness, efficiency and day-ahead price formation in ISO-NE without undue increases in wholesale market costs."

The commission expressed skepticism of the concerns raised by LS Power, writing that the company "does not demonstrate that revenue levels under DASI, which result from market-determined clearing prices, will not be just and reasonable for the purpose of procuring and compensating operating reserves."

In a concurring statement, Commissioner Allison Clements expressed strong support for the changes.

"The DASI reforms appear to be an important step forward for ISO New England's ancillary services market and one reflecting the region's evolving operational needs as its resource mix changes," Clements wrote.

"For a proposal of this complexity to have near universal support in the record and unanimity in the stakeholder process is a testament to the hard work and productive collaboration of many in New England," she added. "It is worth taking a moment to give credit where credit is due." ■

Brookfield Renewables' Bear Swamp hydro project | *State of Massachusetts*

ISO-NE News

NEPOOL Participants Committee Briefs

By Jon Lamson

BOSTON — New England power system emissions decreased by about 3.6% in 2023 compared with 2022, according to the underlying data from ISO-NE COO Vamsi Chadalavada's monthly *report* to the NEPOOL Participants Committee.

Natural gas emissions increased by about 3% in 2023, accounting for about 75% of all power system emissions. Oil emissions dropped drastically, ending the year at about 17% of their 2022 levels. Coal emissions also declined, decreasing by about 43%.

Based on data through Jan. 24, Chadalavada said the energy market value for January totaled $712 million, an increase from $552 million in January 2023. He noted that the monthly peak load was 18,431 MW.

Capacity Market Recommendation

The *meeting materials* indicated that ISO-NE has decided to recommend that it transition its Forward Capacity Market to a prompt and seasonal capacity market, which would reduce the time between the auction and the capacity commitment period (CCP), while splitting the annual CCP into seasonal periods.

ISO-NE noted that its Board of Directors "concurred with management's recommendation to transition to a prompt, seasonal capacity market, which it will discuss next with stakeholders."

At the NEPOOL Markets Committee on Feb. 7, ISO-NE will *propose* a two-year delay of Forward Capacity Auction 19 "to allow for time to design a prompt and seasonal market for CCP 19."

Votes

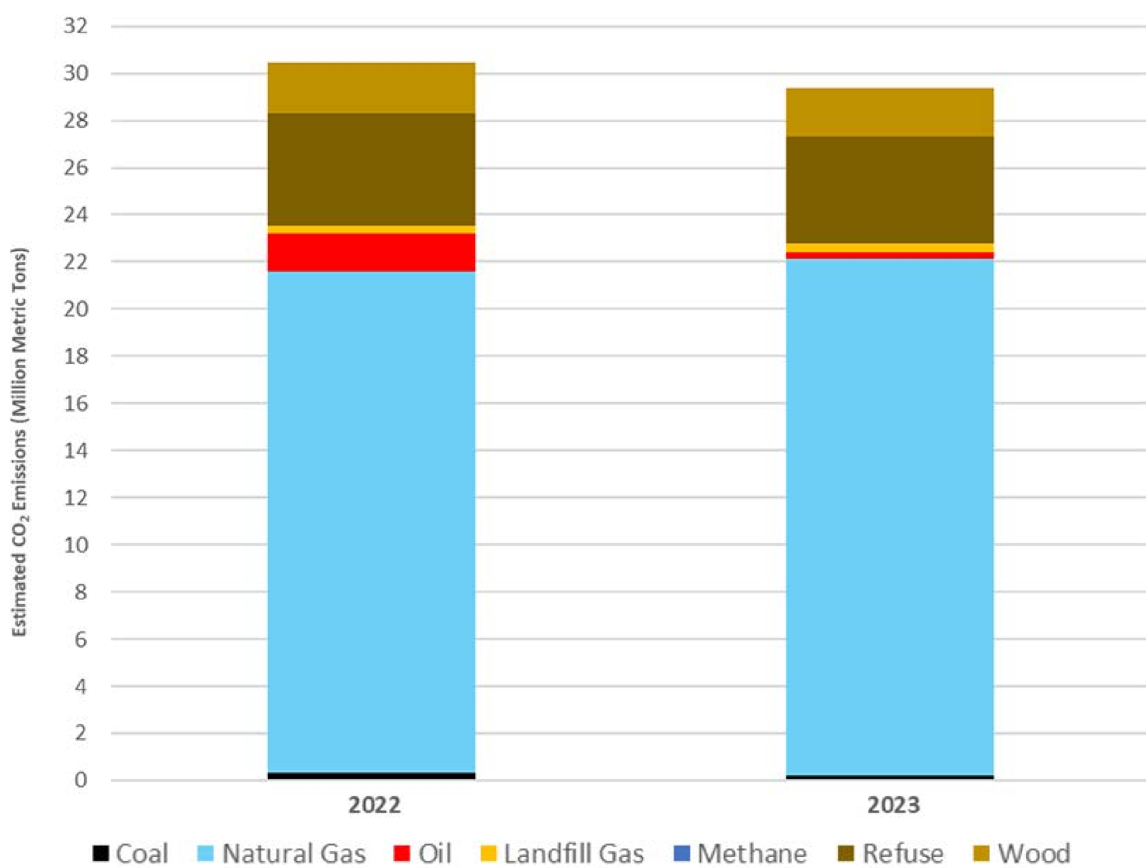
The PC voted to approve ISO-NE's proposal to lower the Forward Reserve Market (FRM) offer cap from $9,000/MW-month to $7,100/MW-month and delay the publication of data from the auction. These changes were initiated in response to *concerns* raised by the ISO-NE Internal Market Monitor about market power in the FRM.

The FRM is designed to procure reserve capacity and is held *twice annually*. In March of 2025, ISO-NE will replace the FRM with a new day-ahead ancillary services market. (See *FERC Approves ISO-NE's Day-Ahead Ancillary Services Initiative*.)

The RTO initially proposed lowering the cap to $6,400/MW-month but adjusted its proposal to $7,100/MW-month following stakeholder feedback and a $7,200/MW-month counterproposal from LS Power that was supported by a vote in the Markets Committee.

The PC also voted to approve changes to its interconnection planning procedures to improve the modeling of inverter-based resources and "update system modeling assumptions to align with the operating conditions expected with the clean energy transition."

The committee also approved tariff changes to assign responsibility to distributed energy resource aggregators to submit their aggregation's metering information. ■



ISO-NE annual CO2 emissions, 2022 and 2023 | *ISO-NE*

MISO News

MISO to Try Again for Interconnection Queue MW Cap, Open Window for 2023 Requests

By Amanda Durish Cook

MISO confirmed Jan. 24 it likely will try again with FERC in the third quarter to apply an annual megawatt cap to its interconnection queue.

FERC in December denied MISO's request to annually cap submittals to its interconnection queue on concerns over too many cap exemptions, the formula to establish the cap and potential resource adequacy deficits from limiting new generation onto the grid. (See *FERC Rejects MW Cap, Approves MISO's Other Stricter Interconnection Queue Rules*.)

MISO said it will apply the rules FERC did approve to the 2023 cycle of project requests, which has been on pause since last year for FERC's decision on the package of more stringent interconnection requirements. The new rules include increased entry fees, an automatic penalty schedule for withdrawing projects and added proof that developers have secured locations for projects.

MISO said it will belatedly open its 2023 queue cycle project window on March 18 and close it on April 18. That cluster of projects will not be subject to a megawatt cap. Currently, the RTO's online generator interconnection portal remains closed to new applications.

MISO hasn't abandoned the idea of a megawatt cap on future queue cycles. The grid operator plans to again propose a megawatt cap that first could apply to the 2024 class of projects.

Aneta Godbole of MISO's resource utilization team said FERC "provided good guidance that MISO will use in its future refiling efforts."

"MISO will come back to the stakeholders once it is ready for further discussion," Godbole said of a second cap filing during a Jan. 30 teleconference of the Interconnection Process Working Group.

At this point, MISO intends to begin processing both a 2023 and 2024 cycle of generation project requests this year. It said if all goes to plan, it could place the 2024 queue cycle deadline at the end of the year.

"MISO is anticipating two cycles in 2024, but it depends on our work to reduce the backlog, the size of the 2023 cycle, the cap filing and approval of the" long-range transmission plan (LRTP) and the MISO-SPP Joint Targeted Interconnection Queue (JTIQ) transmission portfolios, Godbole said. MISO previously said the regional LRTP and the interregional JTIQ will help support new generation interconnections.

Additionally, MISO said either its 2024 or 2025 class of project requests will be the first to proceed under FERC's Order 2023 queue requirements, depending on the final effective date.

Some stakeholders were incredulous that MISO could handle the workload of two queue cycles in a single year given the uptick in project submittals.

"There are a lot of factors on when we hold the next queue cycle," MISO's Andy Witmeier added. He said the RTO wants to be transparent about which factors it foresees dictating when it can open a 2024 queue cycle.

At the Jan. 24 Planning Advisory Committee, Witmeier called a megawatt cap a "vital tool." He also said MISO won't file to apply a megawatt cap retroactively to projects in the queue. ■

| *Minnesota Solar Energy Industries Association*

MISO News

MISO Crunching Data for 2nd Seasonal Capacity Auction

By Amanda Durish Cook

MISO's Carmel, Ind., headquarters | © *RTO Insider LLC*

Key deadlines already have arrived for MISO's spring capacity auction, while the RTO has hiked its planning reserve margin for the 2024/25 planning year.

So far for the upcoming summer, MISO has *accounted* for nearly 161 GW in installed capacity across the footprint that whittles down to almost 129 GW in total seasonal accredited capacity. The RTO must meet a 135.7-GW summer planning reserve margin requirement.

MISO will use a 9% summer 2024 planning reserve margin, higher than the 7.4% annual planning reserve margin used in last year's Planning Resource Auction. MISO said its shifting resource mix and a move to seasonal modeling for its reserve margin contributed to the increase. This year, the RTO said it's using seasonal values, rather than annual, in its generator verification testing data, reflecting different capabilities of generators in different temperatures. The upcoming spring auction marks the second time MISO has divided its capacity auction by season.

MISO *stressed* Jan. 17 that it's "too early in the process to make quantifiable conclusions" on how much supply it expects beginning June 1.

The grid operator plans to update its supply information based on the data it receives from market participants every other week through late March. It said it expects information on energy supply to change "significantly."

MISO resource owners have until Feb. 1 to confirm their seasonal accredited capacity values with the RTO. Load-modifying resource owners also have until Feb. 1 to register to participate in the auction. As of mid-January, MISO said approximately 12.8 GW of load-modifying resources from prior years had not started the registration process. ■

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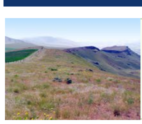
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MISO News

FERC Again Questions MISO Reliability Payments to Wisconsin Coal Plant

By Amanda Durish Cook

FERC once again has determined that the continuing payments MISO is making to a Wisconsin coal plant to stay online to sustain system reliability might be too steep.

The commission in a Jan. 31 order said Manitowoc Public Utilities' proposed $1.16 million monthly compensation to continue operating its Lakefront 9 coal unit as a MISO System Support Resource (SSR) may be unreasonable (ER24-525). It set the matter for hearing, settlement and refund procedures. The new payments took effect Feb. 1.

It's the second time FERC has indicated that Manitowoc Public Utilities is charging too much to maintain grid reliability. FERC in mid-January approved a settlement lowering Lakefront 9's monthly payment to $880,000 instead of the utility's originally requested $1.03 million for the past year. (See *FERC Approves Settlement in MISO Reliability Payments to Wisconsin Coal Plant*.) MISO's SSR agreements must be re-evaluated and extended annually if necessary.

The Wisconsin Public Service Corp. and WPPI Energy protested the amount, voicing concerns over Manitowoc's estimates for labor and maintenance costs, taxes and insurance, legal and consulting expenses, depreciation costs, carrying charges and capital project expenses.

| Manitowoc Public Utilities

Lakefront 9 began operating as an SSR in February 2023 after MISO discovered that thermal overloading and voltage issues could occur on several nearby constraints if the plant was permitted to suspend operations as scheduled. The utility intended to idle Lakefront 9 until 2026, when it could be converted to a renewable fuel source.

MISO has said its members' planned transmission upgrades for the area that will improve system performance and allow it to lift the SSR agreement won't be ready until mid-2028. ■

FERC Orders Change to MISO Order 2222 Compliance Plan

By Amanda Durish Cook

FERC ordered an after-the-fact addendum to MISO's Order 2222 compliance plan this week after being alerted to an inconsistency by WPPI Energy.

The commission said MISO must revise its plan by May 10 to require aggregators of distributed energy resources to retain performance data of individual DERs and provide it to RTOs upon request for auditing purposes (ER22-1640).

FERC agreed with WPPI Energy that it overlooked MISO's missing data requirement — which is required by Order 2222 — when it first issued an order on MISO's plan in October. (See *FERC: MISO's 2030 Finish Date on Order 2222 Compliance not Soon Enough*.)

The commission said while a section in MISO's tariff states it has the right to audit data provided by the aggregator, including information related to the metering of individual DERs, MISO did not include a requirement that aggregators retain individual DER meter data.

WPPI Energy argued that FERC erred when accepting MISO's compliance filing because it didn't explicitly spell out the data preservation requirement.

MISO, meanwhile, continues to work with its stakeholders on other Order 2222 directives FERC ordered in October. Those include deciding whether the grid operator can handle aggregations that span multiple pricing nodes; coming up with a go-live date that's sooner


| © RTO Insider LLC

than 2030; setting up a dispute resolution process; and establishing cybersecurity and customer data privacy protections for meter data management. (See *Stakeholders Ask MISO to Share New Order 2222 Go-live Date ASAP*.) ■

MISO News

ICC Staff Demurs on Decision over Ameren's MISO Membership

Commission Staff Wrap up NOI Without Action

By Amanda Durish Cook

Illinois Commerce Commission staff have passed on recommending that Ameren and two smaller Zone 4 utilities depart MISO for PJM.

ICC staff issued a final report Jan. 25 on the notice of inquiry they opened last year after the ICC directed Ameren to study the cost-benefits of leaving MISO and joining PJM. Ameren commissioned Charles River Associates, which found it would cost southern Illinois customers about $3.4 billion from 2025 to 2034 for Ameren to disentangle itself from MISO and join PJM. The study considered energy trade benefits, transmission expansion to tap into PJM, RTO costs and exit and entry fees to switch grid operators.

In comments on the study last year, ICC staff said PJM's true capacity market style could be a better match for Ameren than MISO's residual capacity auctions. They also said that a continued home in MISO could be fraught with resource adequacy risks when compared to PJM because MISO is poised to add more solar power and energy storage. (See *ICC Staff: More to Consider in Possible Ameren Illinois Exit from MISO*.)

Ultimately, ICC staff said that although they combed through comments on how the study methodology and inputs could be tweaked to show greater future benefits of PJM membership, "it is not clear that implementing such changes would change the conclusion from the Ameren report that Zone 4 joining PJM would result in incremental net costs for [Ameren], ComEd and the State of Illinois overall."

An Ameren Illinois substation expansion in 2021 | *Ameren Illinois*

Staff said they weren't recommending the commission "take any specific action" to change Ameren's — and possibly by extension, City Water Light and Power and Southern Illinois Power Cooperative's — RTO membership.

However, staff added it might be worthwhile for the commission to re-evaluate Ameren's status as a MISO member in the future.

"ICC staff notes that the information submitted in this proceeding suggests that assessing the net benefits of [Ameren's] MISO membership is not a static assessment and will change over time. As a consequence, ICC Staff further recommends the commission leave open the possibility of further analyses should future circumstances warrant them," they wrote. ■

MISO News

MISO to Relax Commercial Operation Deadlines in Interconnection Queue

By Amanda Durish Cook

MISO plans to revise its rules around commercial operation dates to allow interconnection customers to begin operating about a decade after they first enter the queue.

MISO's Brady Mann told stakeholders attending a Jan. 30 Interconnection Process Working Group that the RTO is considering working a few extra years into queue deadlines, recognizing that supply chain squeezes have impeded projects.

That starts with MISO drafting rules specifying that interconnection customers must select a date up to five years on the horizon for their generation projects to reach commercial operation when entering the queue. After that, MISO said it will continue to employ a three-year extension of the original commercial operation date in generator interconnection agreements (GIAs). Additionally, the RTO will allow transmission owners the option to request an extra two-year extension of the in-service date during GIA negotiations. MISO's current tariff language doesn't allow transmission owners to request extensions to complete network upgrades for generation projects during negotiations.

Finally, Mann said MISO will allow for 180 days between a generation project's in-service date and the commercial operation date to account for delays transmission owners might encounter in constructing network upgrades.

The new package of rules could be included in the MISO tariff and business practice manuals and could apply to projects that entered the queue beginning in 2020.

Mann said MISO probably will rely on targeted *FERC* waivers of tariff provisions for the 2018 and 2019 cycle of queue projects that have been especially hard-hit by supply chain woes and stalled in coming online.

MISO plans to make a tariff filing after it weighs stakeholder opinions, which it solicited at the meeting. The RTO told stakeholders last year it would consider extending deadlines after *EDP Renewables* pointed out that generation developers increasingly are exceeding MISO's allotted six-years-from-originally-planned commercial operation and having to turn to FERC for waivers. (See *MISO Somewhat Open to COD Allowances in Interconnection Queue Rules*.)

Current MISO policy requires interconnection customers' GIAs to contain a commercial operation date that's within three years of the date originally requested in their queue applications. It also allows an up-to-three-year extension of the commercial operation date in initial GIAs after execution. When customers can't meet either, MISO can terminate the GIA, causing generator developers to lose their place in line unless they can secure a waiver of their commercial operation dates from FERC. ■

|*Shutterstock*

NYISO News

NYISO Asks FERC for an Extension to Comply with Order 881

Seeks New December 2028 Deadline to Implement and Deploy Software Upgrades

By John Norris

NYISO on Jan. 30 requested a three-year extension to comply with FERC Order 881, claiming it needs more time to implement the software and hardware updates necessary to support the required ambient-adjusted ratings (AARs) on its transmission lines (*ER22-2350*).

Order 881 mandates that providers assess transmission capacity based on real-time environmental conditions, such as temperature or wind, requiring the use of AARs for short-term transmission requests and seasonal ratings for long-term requests (*RM20-16*). NYISO says it needs more time to comply with the order because it also must undertake a multiyear effort to upgrade its Energy Management and Business Management Systems (EMS/BMS), which are critical to monitoring reliability and managing financial operations.

NYISO was slated to implement Order 881's enhancements by the second quarter of 2025 but now is asking for an extension of no later than Dec. 31, 2028, arguing it is infeasible to both comply with the commission's order and deploy the nine EMS/BMS software modifications necessary to support the order's requirements. (See "Ambient-adjusted Ratings," *NYISO Management Committee Briefs: Nov. 29, 2023*.)

The ISO had been upgrading its EMS/BMS software but now contends meeting the current deadline requires a substantial reallocation of resources and personnel, which, it states, "would jeopardize the timeline and quality assurance efforts required to successfully complete a critically important technology upgrade." It added that it cannot use these operating systems past their June 2026 vendor support date "without risking significant software failures."

Moreover, NYISO pointed out transmission owners cannot fulfill their own Order 881 obligations until the ISO has the requisite software and protocols in place. But it assured FERC that if granted an extension, it would maintain certain dynamic line rating functions to still give TOs the ability to modify real-time transmission line ratings.

In an attached affidavit, Rana Mukerji, senior vice president of market structures at NYISO, wrote that a compliance extension was needed because certain modifications "were not anticipated in the initial scope for this technology upgrade project and the initial project schedule."

He cautioned that, in his experience, without an extension, "coding two sets of major modifications in parallel within the same systems significantly increases the possibility that one or both software changes result in increased implementation times and errors."

Mukerji added, however, that if given an extension, it still would take two-and-a-half to three years to complete and implement the EMS/BMS upgrades.

NYISO asks FERC to respond by March 29, because the ISO plans to begin its 2025 project prioritization process in April and wants to know if it can proceed with the EMS/BMS project in the coming year. ■

New York transmission lines | *NYPA*

NYISO News

NYISO CEO Previews 2024 After ‘Successful’ 2023

MC Approves Fast-start Pricing in Day-ahead Market

By John Norris

NYISO CEO Rich Dewey on Jan. 31 spoke to the Management Committee about the ISO’s priorities for 2024 and its accomplishments in 2023.

Dewey called 2023 “a very successful year” and praised NYISO’s staff and stakeholders, urging continued collaboration as the ISO continues working on the challenge of balancing fossil fuel retirements with the introduction of new renewable resources in New York.

“As we look ahead at this grid in transition and the change that we’re seeing across the industry,” Dewey said, “the pace with which we need to navigate these changes is only increasing, which means that we’ve all had to adapt, be flexible and think creatively about how we adapt our market rules and our processes in the year ahead.”

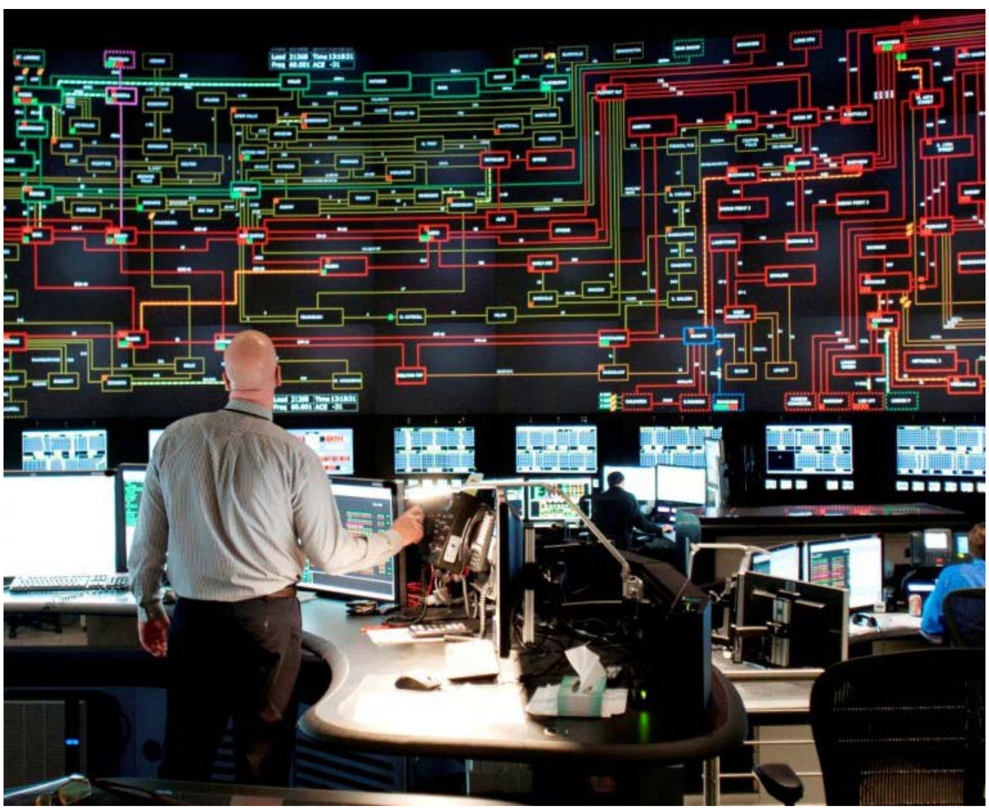
Dewey said that improvements made last year to the ISO’s interconnection queue have already led to a 200% increase in the pace of study completions compared to historical performance. NYISO’s continued work to comply with FERC Order 2023 will be a significant effort in 2024, he said, and that proposals already submitted to the commission would help remove many of the barriers existing in the interconnection process. (See *FERC Approves NYISO Waiver on Interconnection Study Requirements*.)

A top priority this year is monitoring the integration of new projects with the grid and managing the phaseout of existing supplies, while simultaneously accommodating the growing demands of the electrification of housing and transportation. (See *NYISO’s 10-Year Forecast: Challenges Ahead, but No Immediate Needs*.) “Whether it’s offshore wind or other renewable resources, we’re still seeing supply chain issues, as well as interest rate issues,” he said.

Dewey also discussed the public policy transmission need (PPTN) solicitations initiated by the state’s Public Service Commission to bring OSW from Long Island into New York City to both fill predicted reliability shortfalls and achieve the state’s goal of generating 9,000 MW from OSW by 2035. (See *New York PSC Seeks Rehearing of RTO Adder for Offshore Tx Project*.) He said NYISO is “well positioned” to launch the next OSW PPTN, which will be the largest it has ever undertaken, and remains “optimistic” that this effort will be “groundbreaking in terms of the ability to provide new transmission infrastructure that will maximize both the performance of OSW and help mitigate the costs of the buildouts necessary to interconnect them.” (See *NYISO Previews New York City Transmission Needs Assessment*.)

Market development and talent acquisition will also be key priorities for 2024. Dewey said he will “continue to position NYISO’s markets at the top of the stack nationally in terms of efficiency and performance,” but this cannot be done successfully without first attracting, retaining and leveraging the “creative, highly intelligent, dedicated and motivated individuals that remain the primary assets for [NYISO].”

He noted that sector meetings will be held in the first weeks of March, and interested parties must register before Feb. 16. Additionally, the two-day joint Board of Directors and MC meeting is set for June 10. Dewey also encouraged market participants to sign up for the strategic planning sessions in 2024, which will culminate in the annual board meeting in June.



NYISO control room in Albany, N.Y. | *NYISO*

Fast-start Pricing in DAM

The MC *voted* to approve and recommend that NYISO’s board approve *proposed* tariff *revisions* that would provide all fast-start resources with their physical schedules for the day-ahead market (DAM).

The revisions, approved by the Business Issues Committee earlier in January, stem from FERC orders requiring the ISO to modify how it reflects and prices fast-start resources in its energy markets to ensure they are not scheduled below their minimum generation levels. (See *NYISO Approves Update to Fast-start Pricing in Day-ahead Market*.)

NYISO had implemented the changes but realized that it inadvertently extended DAM eligibility to some units that are now receiving ideal schedules below their minimum generation level, potentially causing operational inefficiencies or market imbalances. The approved revisions would provide these units with physical schedules, respecting their minimum generation constraints and preventing them from operating inefficiently.

Following board approval, NYISO plans to submit the revisions to FERC in March. ■

FERC Approves 1st PJM Proposal out of CIFP

By Devin Leith-Yessian

FERC on Jan. 30 approved a PJM proposal to rework several areas of its capacity market centered around aligning how resources' capacity contributions match up to system risk analysis (*ER24-99*).

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

The order greenlights PJM's proposal to accredit all resources, except energy efficiency, using a marginal effective load-carrying capability (ELCC) framework and use the hourly probabilistic modeling at the heart of ELCC to calculate the RTO's capacity needs through the Reserve Requirement Study (RRS). It also adds additional generation capability testing requirements to assess whether generators can meet their capacity performance obligations and whether resources that have not started for a month are able to properly synchronize to the grid and operate according to their parameters. (See *PJM Files Capacity Market Revamp with FERC*.)

The proposal is one of two that the RTO filed following last year's Critical Issue Fast Path (CIFP) process. The other (ER24-98) carries a Feb. 6 deadline for action on proposed changes to PJM's market seller offer cap. (See "PJM Steams Ahead with CIFP Filing Timeline After FERC Deficiency Notices," *PJM MIC Briefs: Dec. 6, 2023*.)

FERC said that the new approach would allow PJM to capture how resources may perform during a wider range of system conditions, namely the sort of correlated outages experienced during extreme winter weather and the diminishing reliability benefit of "highly correlated resources such as solar and short-duration storage."

"PJM's marginal ELCC capacity accreditation framework reasonably values resources' capacity based on their expected incremental contribution to resource adequacy across reasonably anticipated load, weather and resource availability scenarios given the expected resource mix," the commission said. "We find that PJM's proposal will allow its markets to better value the ability of individual resources to address tight system conditions and emergencies, as well as resource adequacy challenges associated with correlated resource outages and an evolving resource mix."

While several protests took issue with the marginal ELCC approach, arguing that it relies on an assumed resource mix before generators have cleared the auction, the commission stated that such *ex ante* analysis has always been part of the Reliability Pricing Model, and the improvements to the accuracy of accreditation values under ELCC outweighs any disparities between the estimated and actual resource mix.

Vistra, American Municipal Power and Ørsted argued that PJM's explanation of how ELCC values would be calculated was vague and that additional information is needed in the tariff revisions, rather than future manual revisions.

The Independent Market Monitor and several generators protested PJM's proposal to add a dual-fuel resource ELCC class, arguing that its qualification requirements are vague and unsupported, and that recognizing the reliability benefit of resources with backup fuel without also creating a new generation class for gas-fired generation with firm fuel contracts is discriminatory.

Calpine commented that the changes were not overly complex, though it also argued that complexity should not be a reason to reject a market design. It compared the use of loss-of-load probability models to how market participants estimate future hourly energy prices.

FERC determined that PJM's proposal to remove generators that fail to provide dual-fuel capability after attesting that they meet the qualifications from the ELCC class, as well as the potential for referral to FERC enforcement, was adequate to address concerns that generators could claim capabilities that they could not deliver. The commission also stated that PJM had demonstrated that it could measure the reliability benefit of resources that maintain an on-site alternative fuel that can allow them to operate for two consecutive 16-hour periods, whereas the definition and benefit of a firm fuel contract remains ambiguous.

The proposal also effectively lowers the maximum penalty generators can be assigned in a year for failing to meet their performance obligations during performance assessment intervals (PAIs). The current annual stop-loss limit is based on the net cost of new entry (CONE), which PJM stated current results in a $135,000/MW-year stop-loss limit it believes is disproportionate to the revenues a generator can receive through the capacity market.

Based on the $18,250/MW-year clearing price, PJM said the stop-loss limit is 7.5 times higher than annual market revenues.

The change to the stop-loss calculation swaps the 1.5 times net CONE component with 150% of the Base Residual Auction (BRA) clearing price. PJM said that the swap would continue to result in a maximum penalty larger than annual revenues without being overly punitive.

The commission rejected arguments from Vistra and Constellation Energy that tying the stop-loss limit to future auction outcomes makes it difficult for market sellers to calculate the Capacity Performance quantified risk (CPQR) component of their market offers, as they would have to estimate the final clearing price in advance. It noted that market sellers already forecast several values ahead of the auction, including energy and ancillary service revenues, expected unit performance and the number of PAIs expected in the delivery year.

PJM's proposal also revised the deficiency charges that fixed resource requirement (FRR) entities are assessed if they fail to procure adequate capacity prior to the BRA. The RTO argued that low capacity prices have created an incentive for FRR entities to pay the deficiency charges, which are based on clearing prices, rather than meet their own reliability needs. It also implements a four-year transition period to provide additional time for FRR entities to adjust to the new ELCC accreditation and a longer lead time for capacity planning.

Commissioner Allison Clements released a partial concurrence and dissent, stating the proposal would address growing reliability risk that does not correspond with meeting peak loads. But she argued that the commission erred in rejecting a protest from the Advanced Energy Management Alliance and clean energy associations that the changes to accreditation and the RRS render the demand response performance window unjust and unreasonable.

Clements wrote that the commission should initiate a show-cause order to examine the "clear mismatch between PJM's existing demand resource availability window and its new understanding of system risk. PJM should be required to either adjust the availability window to reflect its new understanding of risk, or else demonstrate why its proposed changes have not rendered the current availability window unjust and unreasonable or unduly discriminatory." ■

PJM News

FERC Grants AEP Utilities Capacity Obligation Waiver

By Devin Leith-Yessian

FERC on Jan. 31 granted American Electric Power waivers to alter the capacity obligation calculation for four of its vertically integrated utilities in PJM to not include load growth outside their territories (ER24-545).

In its Dec. 4 request, the company said its AEP Ohio affiliate, which participates in PJM's Reliability Pricing Model (RPM), had submitted a forecast large load addition of about 1,860 MW largely attributed to data centers expected to be constructed in its footprint. Under PJM's approach to allocating capacity obligations, AEP said the majority of the responsibility to procure the capacity to serve that load would fall on other affiliated utilities in the AEP transmission zone that participate in the fixed resource requirement (FRR) alternative to RPM. The company estimated that 1,039 MW of the increase would be allocated to Appalachian Power, Indiana Michigan Power, Kentucky Power and Wheeling Power.

"The AEP FRR entities seek this waiver so the forecasted peak load increase associated with the projected large load additions will appropriately remain in the PJM region reliability requirements addressed by the BRA [Base Residual Auction] for delivery year 2025/2026, instead of being shifted to the AEP FRR entities. The waiver will allow the AEP FRR entities' customers to avoid rate impacts caused by the procurement of capacity not needed to serve them," the company said in its request.

The company asked permission to excise the base zonal FRR scaling factor from the calculation of the FRR utilities' capacity obligations, resulting in an equation that multiplies the obligation peak load by the forecast pool requirement (FPR). That would assign the entirety of the capacity obligation for the 1,860 MW to the electric distribution companies within the AEP zone.

AEP's corporate headquarters in Columbus, Ohio | *Electric cat, CC BY-SA 3.0, via Wikimedia Commons*

FERC said in its order that the waiver "will allow the AEP FRR entities to avoid procuring unneeded capacity for purposes of its FRR capacity plan for the 2025/2026 delivery year."

PJM commented that so long as the forecast large load additions are entirely within EDCs participating in the RPM, the waiver has merit, but it requested that the commission confine its approval to the issue at hand, as stakeholders are considering changes to how capacity obligations associated with forecast large load additions are split between FRR and RPM entities within the same transmission zone. The *problem statement* stakeholders are considering, jointly brought by AEP and Dominion Energy, states that high load industries are resulting in concentrated pockets of growth, often within single EDC regions.

"There is stakeholder support for revising the [Reliability Assurance Agreement] to eliminate this impact of the base zonal FRR scaling factor, which seems to be a relic of a time in which increases to load forecasts were more generally experienced across a transmission zone, as opposed to being concentrated within a single EDC's service area," AEP argued in its request. ■

PJM News

Ohio, Pa. Officials Examine PJM Reliability in Joint Session

By Devin Leith-Yessian

Ohio and Pennsylvania lawmakers met in Columbus for a hearing on the future reliability of the PJM grid, quizzing RTO and industry insiders on the role states can have in maintaining resource adequacy.

Much of the Feb. 1 *discussion* centered around the concerns PJM expounded on a year ago in its so-called “4R’s” report (“Resource Retirements, Replacements & Risks”), which laid out a scenario in which a significant number of thermal generators deactivate and take their capacity offline faster than renewables can replace it. (See “PJM White Paper Expounds Reliability Concerns,” *PJM Board Initiates Fast-track Process to Address Reliability*.)

PJM Senior Vice President of Governmental and Member Services Asim Haque — a former chair of the Public Utilities Commission of Ohio — said the RTO has made strides in improving generator performance since December 2022’s Winter Storm Elliott, when 46,124 MW were unable to perform. He pointed to a 16,119-MW peak forced outage rate during the winter storm of mid-January.

Two proposals PJM filed with FERC last year following the Critical Issue Fast Path (CIFP) process aim to further incentivize capacity resources to take the steps necessary to perform during extreme weather and to rework components of the Reliability Pricing Model (RPM) to send the market signals the RTO sees as necessary to address the longer-term resource adequacy concerns at the heart of the 4R’s report. One of those filings (*ER24-99*) was approved by the commission last week, while an order on the other (*ER24-98*) is expected Feb. 6. (See related story, *FERC Approves 1st PJM Proposal out of CIFP*.)

While PJM is adjusting its markets to address the possible imbalance between retirements and new entries, Haque said the majority of the anticipated deactivations through 2030 are because of state and federal policies.

“Part of the reason we’ve been doing this sort of road tour is this concept of avoiding policies that push resources off of the grid until a replacement quantity has been added to the grid. So this is something that we’ve been trying to tout and explain to policymakers across the footprint,” he said, adding that the other side of the coin is finding ways of working with states to speed development of new generation.

PJM Senior Vice President of Governmental and Member Services Asim Haque speaks during a joint public hearing held by Ohio and Pennsylvania lawmakers Feb. 1. | *Ohio House of Representatives*

ReliabilityFirst President Tim Gallagher said its latest reliability study identified policy decisions as a top risk to the grid for the first time and urged legislators to ensure that changes are designed to leave time for analysis to understand potential ramifications.

“Right now it looks to me like the effort to remove conventional resources from the grid is outpacing our ability to keep up with it. … None of the problems associated with transitioning to a greener grid are unsolvable or insurmountable; they just take time, and they take money. So I think the single biggest thing you can do as policymakers is ask the right questions,” Gallagher said.

Public Utilities Commission of Ohio Chair Jenifer French said PJM’s focus should be on maintaining reliability and a diverse portfolio of generation types to avoid overdependence.

“We must refocus PJM’s capacity market on its basic purpose — resource adequacy and reliability — rather than the promotion of state or federal policy initiatives that undermine that purpose,” she said.

NERC President James Robb said the 1-in-10 reliability target long used in the electric industry is on its way to becoming antiquated as growing electrification decreases consumers’ tolerance for grid outages that may disrupt home heating or electric vehicle charging. As those changes in consumer demand drive load growth not seen in decades, Robb said new risk vectors demand the attention of grid operators and regulators.

The inverter-based resources substituting for coal, gas and nuclear generators raise questions about their ability to provide essential reliability services, such as frequency control, Robb continued. Significant load growth is also occurring rapidly and in regions that have historically had flat load profiles, both because of electrification and energy-intensive industries like data centers. Threats from bad actors also are manifesting, with hackers targeting utilities in ransomware attacks and extremist groups damaging physical infrastructure.

One of the largest obstacles to addressing those risks is constructing new transmission and gas pipelines, Robb said. He noted that the only major interstate power line built in the past 20 years, the 500-kV SunZia line between Arizona and New Mexico, took 17 years to get

PJM News

final construction permits.

"That's completely out of whack with the pace of change that we're dealing with. … It's due to issues such as cost allocation; it's due to issues such as siting; and it's due to a range of policy issues that are making it very, very hard to legitimize projects to attract investment," he said.

Ohio state Sen. Kent Smith (D) said PJM is sounding the alarm on resource adequacy and reliability, but he noted that in its December 2023 Long-term Reliability Assessment, NERC rated the RTO as being at normal risk.

Robb said the level of risk it has seen across the U.S. has been steadily growing to now include elevated concerns with PJM's neighboring balancing authorities, raising the possibility that those regions will lean on the RTO during emergencies. He added that the 4R's report looked at a longer horizon than NERC's annual analysis and predicted that the risks it presented will manifest in assessments released over the next few years.

Pennsylvania state Sen. Gene Yaw (R), chair of the Senate Environmental Resources and Energy Committee, asked what obstacles there are to new resources coming online to meet the growing imbalance between supply and demand.

"PJM has had to get its house in order to ensure that our markets appropriately reflect what we are seeing in this energy transition and incent reliability," Haque said. "So we've done capacity market reform; there's one more filing that's outstanding, and it relates to market power mitigation, and in our opinion, the market is being over-mitigated right now." He added that additional changes are being made to the reserve and regulation markets.

Speaking on the hearing's second panel of the day, Glen Thomas, president of GT Power Group, said there are also numerous market structures at PJM that are discouraging investment in the RTO's capacity market. He pointed to FERC's 2021 approval of a tightened minimum offer price (MOPR) that allowed resources receiving state subsidies to avoid being mitigated to their cost-based offers, a stringent market seller offer cap (MSOC) and Capacity Performance (CP) penalties exceeding $1 billion following Winter Storm Elliott. (See *3rd Circuit Rejects Challenges to PJM MOPR, Affirms Authority over FERC Deadlocks*.)

Thomas said comments submitted by the Pennsylvania and Ohio utility commissions were instrumental in supporting the CIFP proposal the commission approved in January and encouraged the states to remain engaged at the federal level, both with FERC and on EPA rule proposals.

Ohio Manufacturers' Rebuttal

The Ohio Manufacturers' Association (OMA) questioned PJM's message that long-term reliability is at risk in a Jan. 31 briefing, raising commissioned analysis of the 4R's report that suggested that the RTO had not adequately accounted for shifting market signals if resource deactivations accelerate and intermittents fail to keep up.

Go Sustainable Energy CEO John Seryak, who drafted OMA's *rebuttal* to PJM's study, said in such a scenario the capacity market would automatically produce market signals that would incentivize developers to speed up or make investments that allow existing resources to comply with the environmental regulations the RTO predicts may cause their deactivation.

OMA President Ryan Augsburger argued that PJM is overstating reliability risks in a manner that will lead to higher rates for consumers and said repeat tinkering with the capacity market design has led to delays in running Base Residual Auctions, depriving investors of market signals and confidence in the markets.

"While Ohio manufacturers agree that future shortfall risks should be taken seriously, we believe that PJM's 'Resource Retirements, Replacement & Risks,' or 4R's report, overstates this situation and only caters to the desires of its utility company members to justify expensive new investments that they will pass on to ratepayers, thus exposing manufacturers and others customers to significant new costs," Augsburger said.

Brad Belden, president of Belden Brick and chair of the OMA Energy Commission, said PJM needs to balance reliability with customer affordability to avoid onerous electric rates that discourage economic growth.

"The OMA-commissioned review of the grid operator, PJM, raises a lot of questions that remain unanswered by PJM," Belden said. "Their own report showed that new gas and renewable power, along with much of our existing generation, could meet the meets through 2030, even with any plant retirements, but PJM is seeking changes to its markets that could be costly. With plenty of natural gas and renewable energy waiting in line to provide power, we're not sure why PJM is making costly changes."

Ohio Consumers' Counsel Maureen Willis said her office protested the CIFP filings, arguing that they should not be made prior to the next capacity auction and that further understanding is needed to understand the costs they could pose for ratepayers.

"There's this push by PJM and others to scare lawmakers and other regulatory authorities into acting immediately without actually considering the consequences of their actions or without knowing the costs to consumers," she said. ■

PJM News

PJM Stakeholders Open Poll on Proposal to Align Gas and Electric Markets

By Devin Leith-Yessian

PJM's Electric Gas Coordination Senior Task Force has opened a poll on a proposal aimed at aligning components of the RTO's energy market with gas pipeline operations.

The *joint package* sponsored by PJM, Dominion Energy and Gabel Associates would add intraday real-time commitment runs to the day-ahead market ahead of the three gas nomination cycle deadlines and notify gas-fired generators that they are being committed with adequate time for them to nominate for fuel in the subsequent cycle. In turn, generators would be asked to notify PJM if they have procured fuel or expect to do so in time to be scheduled.

Speaking during a Jan. 30 task force meeting, PJM's Brian Fitzpatrick said the proposal is focused on improving situational awareness over the status of gas generators and reducing the need for operators to check in with the approximately 300 such resources during emergency conditions.

"Really it's about reducing the unknowns and identifying where there are risks," he said.

Having multiple commitment periods throughout the day corresponding to the gas nomination cycles would give PJM insights into when resources are likely to be available, such as whether they have obtained fuel for evening peaks.

Voting on the proposal will be open for around two weeks, and results are expected to be discussed at the task force's Feb. 29 meeting. This is the second poll the task force has held, following a *round* in which six packages failed to receive majority support in October.

The highest vote-getter was a joint proposal sponsored by PJM and Dominion, which would have required gas generators to confirm to PJM that they had procured adequate fuel to meet their day-ahead commitment. It would have also required that resources that had not procured fuel during a PJM cold weather alert verify gas availability with pipeline operators twice a day and reflect any shortages as a forced outage.

Michael Borgatti, Gabel senior vice president of RTO services and regulatory affairs, said he's hopeful that the joint proposal can be a compromise between all those previously brought to the task force.

The revised package now under consideration


Brian Fitzpatrick, PJM | *© RTO Insider LLC*

states that generators should confirm the availability of their fuel supply and reflect that in their parameters, but Fitzpatrick said it would not carry any enforcement or penalties.

Brock Ondayko, director of RTO operations for AEP Energy, said that even without any specified penalties at PJM, generators that report incorrect information — such as stating that a unit has purchased fuel and then experiencing an interruption in supply — could run into compliance issues with FERC.

Independent Market Monitor Joe Bowring said the fuel reporting component is vague and would be ineffective at providing true situational awareness without stronger requirements. In particular, he said allowing generators to state that they expect to have fuel available would add too much ambiguity to the process.

"It is creating false confidence, so I really don't see the point of this," he said. "In my view this is potentially worse than not having it. ... The straightforward approach is to have a mandatory requirement to report whether a unit has procured gas. Combining the voluntary reporting in the proposal with reporting about what generators expect makes that part meaningless or worse than meaningless. A rule based on a generator's expectation is an unenforceable rule."

Vistra Director of PJM Market Policy Erik Heinle said the deadlines for reporting information to the RTO could distort the gas market if a large number of generators are trying to get contracts in place at the same time.

Bowring also said that the proposal would be a significant change to PJM's day-ahead markets that has not included a careful review of how the interaction with markets would work and the likely consequences.

"Issues including whether the commitment process prior to the day-ahead market would use the same software and have the same objective function have not been addressed. Issues about how market payments and uplift payments would be defined and the treatment of commitments prior to the day-ahead market that carry forward into the next day have not been carefully thought through. The Market Monitor supports increased situational awareness and supports inclusion of offer parameters that are consistent with pipeline rules, but this proposal is being rushed to a vote before important questions have been asked, let alone answered," Bowring said. ■

SPP News

SPP Directors Pleased with Progress of Markets+ Tariff

By Tom Kleckner

SPP's two independent directors with backgrounds in the Western Interconnection both expressed relief and optimism at the grid operator's collaborative efforts with stakeholders to develop Markets+ in the West.

The comments came during a conference call Feb. 2 with members of the Markets+ Participant Executive Committee (MPEC) and the Markets+ State Committee (MSC).

"Honestly, a year ago, I was probably a bit skeptical about the potential for being in this position of essentially the major tariff issues being resolved in less than a year," said Steve Wright, a former Bonneville Power Administration administrator and CEO. "The progress is really amazing. An incredible array of folks have come to the table and found compromise on what have been intractable issues in the West in the past."

John Cupparo, a former officer with PacifiCorp and experienced in several other western initiatives, pointed to stakeholder approval rates in the 90s on votes for tariff language and other issues and lack of appeals to decisions already made as evidence of a job well done.

"From my perspective, this is truly reflective of a market for the West, designed by the West and governed by the West," he said.

Along with director Liz Moore, Wright and Cupparo constitute the Interim Markets+ Independent Panel (IMIP), the temporary body overseeing the day-ahead market's development. The directors listened to several reports on last month's MPEC meeting and approved 15 pieces of language related to the Markets+ tariff and its attachments.

The IMIP also approved modifications to the independent sector's voting structure, previously approved by the MPEC. (See "Independent Sector Changes," *SPP Markets+ Participants Executive Committee Briefs: Jan. 23-24, 2024*.)

The primary remaining sticking point is what's been called a "gap" with the accuracy of information to be shared with SPP's Market Monitoring Unit under FERC's duty-of-candor requirements. SPP, the MSC, the MMU and western legal groups are all involved in resolving the issue.

MSC member Ann Rendahl, a commissioner with the Washington Utilities and Transportation Commission, said "much" progress has been made since the January MPEC meeting. The various entities involved met the week after MPEC and are planning to resume discussions this week.

"We see this moving in a direction that will address the outstanding concern that we have. We're optimistic that the language can be worked through the Markets+ process in the coming weeks and adopted into the tariff," Rendahl said.

"Everyone engaged in this exercise is invested in building a robust, transparent market that earns the trust of parties throughout the West," she added. "We're all well aware and understand the long history of market development in the West. There's considerable scar tissue in the West surrounding prior experience with significant adverse customer-rate impacts associated with price and market manipulation."

A reference, perhaps, to the western energy crisis of 2001 instigated by Enron in California, and hopefully, soon to be forgotten. ■

SPP's independent directors praise the RTO's efforts to develop Markets+ in the Rockies and beyond. | *© RTO Insider LLC*

Company Briefs

Georgia Power Says Vogtle Delayed Again

Georgia Power on Feb. 1 announced that a malfunction within the cooling system at the second of two additional nuclear reactors at Plant Vogtle will force it to delay the unit's in-service date until the second quarter of 2024.

In a filing with the Securities and Exchange Commission, the company said vibrations associated with certain piping within the cooling system at Unit 4 were discovered during startup and preoperational testing. The problem has been fixed. Before the discovery of the vibrations, the unit was expected to be finished in the first quarter.

More: *Capitol Beat*

Former Entergy President, CEO Packer Dies at 76

Dan Packer, who served as president and CEO of Entergy New Orleans for more than a decade, died Jan. 31. He was 76.

Packer's tenure at Entergy ran from 1996 to 2006, which included the Hurricane Katrina disaster. His career with the company began in 1982 at Waterford 3 Nuclear Plant, where he was a training manager before he became the plant's manager. He was then named president in 1996 and CEO two years later.

More: *Nola.com*

Volvo to Stop Polestar Funding

Volvo Cars on Feb. 1 announced it will stop funding subsidiary Polestar Automotive.

The group announced it may hand stewardship of the ailing luxury EV brand over to majority Volvo shareholder, China's Geely Holding, which has a 78.65% stake in the company, according to LSEG data. Volvo Cars holds around a 44% stake in Polestar, having acquired the company in 2015. The brand has struggled since going public in June 2022, and analysts were wary that it had become a drag on Volvo's resources.

More: *CNBC*

Federal Briefs

Holtec to Get $1.5B Loan from DOE to Reopen Palisades Nuclear Plant

Holtec International is set to receive a $1.5 billion conditional loan from the Department of Energy this month to help restart the Palisades nuclear power plant in Michigan, a person with knowledge of the matter said Jan. 27.

Holtec bought Palisades in 2022 from Entergy to decommission the plant. After interest arose from the Biden administration regarding low-carbon power from nuclear energy, Holtec filed to reopen the 800-MW plant in October while also applying for an LPO loan.

The Biden administration recently finalized $1.1 billion in credits to keep PG&E's Diablo Canyon nuclear power plant in operation in California.

More: *Reuters*

Podesta to Replace Kerry as Top Climate Adviser

White House officials confirmed Jan. 28 that President Biden will tap senior adviser **John Podesta** to replace outgoing special climate envoy John Kerry once Kerry steps down this spring,

Podesta, now a senior adviser on clean energy and a veteran Democratic strategist, will remain at the White House rather than move to the State Department in his new role, which had not previously been reported. His new title will be senior adviser to the president for international climate policy.

More: *The Washington Post*

Energy Information Administration to Track Crypto Mining Power Use

The Energy Information Administration on Jan. 28 said it will begin to more closely track electricity consumption by cryptocurrency mining companies operating in the U.S.

The EIA said it plans to launch a survey next week of select bitcoin miners, which will be required to respond with their energy use details, as part of an emergency data collection request authorized by the Office of Management and Budget on Jan. 26. It will focus on how power demand for cryptocurrency mining is changing, as well as identifying parts of the country where mining growth is concentrated and the electricity sources used for the operations.

More: *Reuters*

Lawmakers Want to Probe Chinese Firms Involved in Ford Battery Plant

The chairs of U.S. House committees asked the Commerce Department on Jan. 26 to investigate four Chinese companies they claim are involved in Ford's planned Michigan battery plant.

Rep. Mike Gallagher (R-Wis.), who chairs the select committee on China, and Rep. Cathy McMorris Rodgers (R-Wash.), who chairs the Energy and Commerce Committee, urged the department to investigate and impose export restrictions on the four companies they claim are involved in the "facility's design, construction and information technology processes." The letter claims the companies have direct ties to the Chinese military, Chinese Communist Party, North Korean government and alleged human rights abuses in China's Xinjiang region.

In September, the two lawmakers demanded documents from Ford tied to its CATL partnership and threatened to call CEO Jim Farley to testify before Congress.

More: *Reuters*

Biden Admin Faces Pushback on Papua New Guinea Gas Project

As the Biden administration pauses its approval of liquefied natural gas export terminals in the U.S., it faces another big decision overseas regarding a project in Papua New Guinea led by TotalEnergies and Exxon Mobil.

A $13 billion LNG export project in the country is on a shortlist of projects set to receive financing from the U.S. Export-Import Bank, which supports American businesses around the world.

While the project promises to bring wealth to one of the world's poorest nations while also moving it away from coal, climate activists say the project will add more than 7% to the nation's energy and industry emissions.

More: *The New York Times*

State Briefs

CALIFORNIA

Senate Confirms Noemí Otilia Osuna Gallardo as Energy Commissioner

The state Senate on Jan. 30 confirmed Commissioner **Noemí Otilia Osuna Gallardo**'s appointment to the energy commission by Gov. Gavin Newsom (D).

Gallardo joined the commission as its public advisor in 2019 before becoming the chief of staff for Chair David Hochschild.

More: *California Energy Commission*

Tesla to Pay $1.5M for Handling of Hazardous Waste

Tesla on Feb. 2 agreed to pay a $1.5 million fine to settle a lawsuit over its handling of hazardous materials in the state.

The Environmental Division of the San Francisco District Attorney's Office started its investigation in 2018 and found that Tesla, which owns 57 car service centers along with 18 solar energy facilities around the state, illegally disposed of waste, including lubricating oils, brake cleaners, lead acid, batteries, aerosols, antifreeze, waste solvents and electronic waste paint.

More: *The Fresno Bee*

CONNECTICUT

Attorney General Files Lawsuit to Compel English Station Site Cleanup

Attorney General William Tong on Jan. 31 said he has filed a lawsuit against United Illuminating and parent company Avangrid for "dragging their feet" on cleanup of the closed English Station power plant site.

Tong's lawsuit is seeking $25,000-a-day fines for each of six alleged violations, as well as a permanent injunction requiring UI to take "whatever action is necessary" to fulfill its legal obligations to clean up English Station. The fines the state seeks would be in addition to a $2 million-a-year penalty already assessed by the Public Utilities Regulatory Authority.

UI later refuted Tong's comments in a statement, saying it has "gone above and beyond its obligations for the cleanup of English Station."

More: *New Haven Register*, *Hartford Courant*

INDIANA

EPA OKs State's First Carbon Dioxide Wells

EPA on Jan. 31 issued permits for the state's first two "wells" that will be used to store carbon dioxide underground.

Wabash Carbon Services said the permits will allow the company to construct its ammonia fertilizer plant in Terre Haute. The company plans to transport the CO2 generated from manufacturing the fertilizer to two wells that will be sunk deep beneath sites in Vigo and Vermillion counties.

The permits, which take effect in March, allow the company to store the CO2 4,000 to 5,000 feet underground.

More: *Indianapolis Star*

LOUISIANA

PSC Approves Sterlington Solar Facility

The Public Service Commission on Jan. 29 approved Entergy's plans to construct the Sterlington Solar Facility in Ouachita Parish.

Construction of the 49-MW plant is expected to begin by the end of 2024 and be completed by 2026.

More: *KTVE/KARD*

MINNESOTA

Xcel Looks to extend Life of Prairie Island Nuclear Facility, Add Gas Plants

Xcel Energy on Feb. 1 said it wants to extend the life of its Prairie Island nuclear power plant by 20 years, as well as significantly invest in large-scale battery storage and build two natural gas plants.

The utility had hoped to keep its two units at Prairie Island running for an extra 20 years after licenses expire in 2033 and 2034. Last year, it applied to federal regulators for another 10-year extension to 2050 for its Monticello plant. But Xcel had not officially asked for a Prairie Island extension until now and still needs federal approval. The company also looks to add 2,200 MW in two natural gas plants.

Xcel declined to provide a cost for the plan, which must be approved by regulators.

More: *Star Tribune*

NEW JERSEY

BPU Welcomes New Commissioner

The Board of Public Utilities on Feb. 2 welcomed Michael Bange as its newest commissioner.

Bange was nominated by Gov. Phil Murphy (D) and unanimously confirmed by the Senate in December 2023.

Bange replaced MaryAnna Holden.

More: *NJBPU*

NORTH CAROLINA

Duke Proposes New Natural Gas Plant, Small Nuclear Reactors

In a filing with the Utilities Commission on Jan. 31, Duke Energy proposed to build a new natural gas plant in Person County and three small modular nuclear reactors in Stokes County over the next decade.

Duke estimated that construction costs would hike average monthly bills for residential customers by 39% over previous estimates in 2033. Duke Energy Carolinas customers would pay 73% more per month.

The commission could rule on the plan by late 2024.

More: *NC Newsline*

OKLAHOMA

Avangrid Lays Out Plan for Wind Project

Avangrid on Jan. 30 announced plans to build a 147.5-MW wind farm that will be its first renewable energy project in the state.

The Pontotoc Wind farm, at a site selected in collaboration with the U.S. Air Force, will feature 33 turbines and last for 20 years.

Construction is expected to start this year.

More: *Renewables Now*

SOUTH DAKOTA

Senate Passes Hydrogen Pipeline Regulation

The Senate Commerce and Energy Committee on Jan. 30 voted 5-3 to advance a bill that would require hydrogen pipelines to go through a permitting process with the Public Utilities Commission.

The bill, which already passed the House 66-3, will move to the Senate floor.

More: *KELO*

TEXAS

ERCOT Sets Solar Energy Record

ERCOT broke its record for its grid-share of solar produced energy Jan. 26 when 36.11% of its output came from solar resources.

According to ERCOT, demand reached 15,222 MW at 10:09 a.m. before the record was broken later that day.

More: *KUT*

UTAH

Rep. Jack Presents 2 Energy-related Bills to Committee

Rep. Colin Jack (R-St. George) on Jan. 29 presented two energy-related bills to the House Public Utilities, Energy and Technology Committee.

One bill would have the Public Service Commission require a utility to replace a coal plant with a resource that produces an equal or greater amount of power and has similar attributes to coal power. The other bill would rewrite the state's energy policy, ranking the attributes that legislators want in energy as, in order: adequate, reliable, dispatchable, affordable, sustainable, secure and clean.

The committee voted to advance the bills along party lines.

More: *The Salt Lake Tribune*

Senate Committee Advances Coal-related Bill

The Senate Natural Resources, Agriculture and Environment Committee on Jan. 31 voted 4-2 to advance a bill that would require the Intermountain Power Agency to notify the state a year in advance of its intent to close the coal plant.

When that happens, the Public Service Commission would be required to hold a public hearing within 60 days "for the purpose of establishing the fair market value of the electrical generation facility." After the hearing, the PSC would have 30 more days to come up with a figure of fair market value. After that, IPA would have 90 days to offer the plant to the public.

If that offer returns bids at or above the set price, IPA would be required to sell to the highest bidder. If no one makes an offer matching the set value, IPA must offer it to the state at the fair market price.

More: *The Salt Lake Tribune*

VIRGINIA

Dominion OSW Farm Earns Final Federal Approvals

Dominion Energy on Jan. 30 earned the final two federal approvals needed to move forward with the construction and operation of its $9.8 billion, 176-turbine Coastal Virginia Offshore Wind project off the coast of Virginia Beach.

The Bureau of Ocean Energy Management granted final approval of the construction plan for the 2.6-GW project, while the U.S. Army Corps of Engineers issued its permit to allow for permitted impacts to U.S. waters.

Construction is expected to begin in May.

More: *Virginia Business*

Surry County Endorses Data Center

The Surry County Planning Commission on Jan. 29 unanimously endorsed Green Energy Partners' plans to build a combination data center and hydrogen fuel hub adjacent to Dominion Energy's nuclear power plant.

The Surry Green Energy Center will initially be connected to Dominion's grid, but plans call for eventually powering the site with four to six small, modular nuclear reactors.

The company expects to break ground this year, which will be the project's first phase conditional on it receiving rezoning approval.

More: *The Smithfield Times*