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EPSA Competitive Power Summit

PJM Chief Tells EPSA Retirements Need to Slow down

By Rich Heidorn Jr.

WASHINGTON — PJM needs to slow the pace of generation retirements to avoid reliability problems by the end of the decade, CEO Manu Asthana told the Electric Power Supply Association last week.

In a keynote address to EPSA's Competitive Power Summit on March 21, Asthana said PJM faces increasing loads from electrification and data center growth and that new supply resources have not kept pace with retirements because of clogged interconnection queues, siting obstacles and supply chain constraints.

"I think the math is pretty straightforward," Asthana said. "I think we need to add [supply resources] faster … but I also think we need to subtract slower and subtract generation only when the replacement generation is here at scale. I really think that's critical."

In February, PJM's Board of Managers invoked an accelerated stakeholder process to address the potential generation shortfall, which the RTO outlined in a staff *white paper*.

PJM currently has 190 GW of installed capacity to serve its 150-GW peak load, "a very healthy reserve margin," Asthana said.

But by 2030, PJM expects its data center load could rise to 10 to 15 GW in addition to increasing loads from electrification of heating and transportation.

The RTO forecasts at least 40 GW of generation is at risk of retirement by 2030. "So … suddenly, that 150-GW/190-GW reserve margin starts to look really not enough by 2030," Asthana said.

Most of the retirements are expected because of state and federal environmental and climate policies.

"Policy reasons are harder to reverse. It's not that you can send a market price signal that will necessarily override policy signals," Asthana said. "It is worth noting, though, that several of our states have worked with us to put reliability offramps in place for their policies."

New Jersey will allow generators to seek an extension of CO_2 compliance deadlines if a unit shutdown would impact grid reliability. Illinois officials will allow generators to seek limited, temporary exceptions to the emissions ceiling in the Climate & Equitable Jobs Act "if they are deemed necessary to maintain the reliability of the Bulk Electric System."

Asthana said PJM is attempting to solve the challenge by streamlining its interconnection process, fine-tuning capacity accreditations of resources and considering changes to the capacity market.

Having won FERC approval for its revised queue procedures, Asthana said PJM is working "feverishly" to hire additional staff and consultants and automating processes to increase its interconnection throughput. "I'm not sure that's going to be enough," he said, citing "supply chain pressure" and siting issues.

Although the RTO has 260 GW of proposed resources in its queue, last year less than 2 GW was added to the system. "When you do the math — when you look at the rate of retirements, you look at the rate of growth, and you add in the current rate of throughput for our queue — we are headed for some trouble. And that trouble is likely to find us later in this decade," Asthana said.

Increasing Winter Risks

Asthana said the stakeholder process is focused on the capacity market, including modeling the RTO's increasing reliability risks in winter and whether changes are needed to the Capacity Performance (CP) construct.

The week before, PJM had presented the Resource Adequacy Senior Task Force a preliminary proposal to overhaul its capacity market. The RTO said its proposal would improve modeling, resource accreditation, testing and market power mitigation rules. (See *PJM, Stakeholders Present Initial Capacity Market Proposals to RASTF*.)

CP, which increased performance bonuses and nonperformance penalties, was initiated *in response* to widespread outages during the 2014 polar vortex. Yet during the bitter cold over the Christmas weekend last year, one-third of gas-fired generation in the RTO's Northeast was unable to operate because of inadequate winterization, Asthana said.

"We had actually asked this question of the gas industry after Winter Storm Uri in Texas around our vulnerability in our region to that sort of freeze-off. And I think we and the gas industry believed that actually we were adequately weatherized up in the Northeast. And it turns out, we encountered a condition for which we were not ready," he said.

PJM expects to issue at least $1 billion in CP penalties over the generation outages. (See *PJM Weighs Options for Winter Storm Elliott Follow-up*.)

"I think it's appropriate for us to ask ourselves is that [CP] penalty structure correct [for] the future? Did it achieve what it needed to achieve? Do we need to make modifications to it? And also, I think it's appropriate to ask, is the risk that capacity suppliers are taking on as a result of their capacity commitment and that capacity penalty structure — are they able to pass that through in their offers?"

Asthana dismissed suggestions that PJM's challenges require abandoning competitive markets. "I know there are voices out there that are using this opportunity to say, 'Hey, are markets actually the right tool to do this? And I think that drumbeat is going to just continue, because there are a lot of people that have entrenched positions against markets," he said.

"I would submit to you [that] every grid operator in the world is struggling with these questions, whether they are markets-based, whether they are not markets-based. And in fact, within PJM, we have vertically integrated utilities; we've got restructured utilities; we've got a whole mix of participants, who have all benefited from our market structure that we have collectively put in place and nurtured over the last 25 years. And the evidence is strong that there are billions of dollars of efficiency [obtained] through the power of competitive markets. And so, I encourage everyone to remember that as we think about the future and think about designing the changes to our markets. They're complex, but very, very necessary, and very, very worth it."

EPSA CEO Todd Snitchler, who led a question-and-answer session after Asthana's speech, said PJM's challenges are "a five-day-a-year problem. It's not a 365-day-a-year problem. But it's mission-critical when it happens."

Snitchler noted that PJM's 13-state footprint includes states such as Maryland and New Jersey, which have adopted aggressive climate policies, and fossil fuel-producing states such as Ohio and Pennsylvania. Does PJM tailor its message based on the audience, he asked?

No, said Asthana, describing the RTO as "the interested truth teller."

"We're interested in reliability; we're interested in helping our states achieve their decarbonization objectives as well, but doing it reliably," he said. "So we try to say the same thing … regardless of who we're talking to.

"We don't have different messages for different audiences. That would not work, because they talk to each other." ■

EPSA Forum Speakers Focus on Hurdles to Energy Transition

By James Downing and K Kaufmann

WASHINGTON — The energy transition still presents some key hurdles that need to be overcome for it to occur successfully, speakers said at Electric Power Supply Association's (EPSA) Competitive Power Summit last week.

"We need to think broadly about how we can collaborate to ensure reliability," EPSA CEO Todd Snitchler said March 21. "We're looking at working through a period of energy expansion, not merely passively watching an energy transition."

Getting to 100% renewable power plus electrifying key new areas of demand such as home heating and transportation means the industry will have to build more supply than it has now as it cleans up its generation stack, he added.

"Reliability has been a top priority for as long as competitive markets have been in place, but competing interests from policymakers and regulators have drawn attention away from that first responsibility," Snitchler said.

NERC CEO Jim Robb noted that the industry has been through a number of high-profile events in recent years that have kept his organization busy, from winter freezes to physical attacks on grid infrastructure.

"Many of the issues and challenges that we're starting to see are really coming at us through the generation side of the business, which is a little bit different than what we dealt with when the ERO was originally stood out in the mid-2000s," Robb said. "And those issues are particularly around fuel supply and energy production."

The key challenge facing the grid is reliably transitioning to a more intermittent resource mix while preserving the key reliability services that traditional, synchronous power plants provide. The grid's dependence on natural gas and the lack of coordination were "exposed in Technicolor" during the outages in Texas and its neighboring states in February 2021, Robb said.

"Managing the pace of this transition is going to be key to being able to navigate it successfully," Robb said. "And we've seen, through our reliability assessments, a steady decline in the risk profile of the sector over the last five years. And that's in spite of a very strong aggregate performance, but the risks are clearly growing."

Extreme weather is becoming more commonplace, and that has huge impacts on demand, especially in markets that use electricity for heat.

EPSA CEO Todd Snitchler (left) and LS Power Generation President Nathan Hanson | © *RTO Insider LLC*

"Once the temperature drops to a point where heat pumps can perform, and you switch to electric resistance heating, the demand goes pretty much vertical," Robb said. "That I think is going to be one of the main headlines coming out of our inquiry into Winter Storm Elliott," referring to the storm that led to outages in the Southeast over the holidays late last year.

The changing grid also means that weather has a greater impact on generation, as too little or too much wind can knock out power from that renewable resource, or snow and clouds can block sunlight from reaching solar panels.

NERC has recently implemented winterization standards that it started after a cold snap in 2018 and were updated after the winter storm of February 2021.

Robb said that NERC needs to step up the pace of developing new standards so it can adequately respond to the changing grid, but efforts at streamlining the standards development process hit a snag earlier this month when a set of proposed changes to the organization's *Standards Processes Manual* (SPM) failed on its first ballot. He said that industry stakeholders had not been particularly constructive in that effort.

"Our goals here are to speed the process, eliminate low value-added time sinks; actually maintain stakeholder engagement, stakeholder ownership of the outcomes; and we do want to give the board the authority to set meaningful deadlines to move things along," Robb said.

The proposed SPM changes included creating a tiered system of comment periods, under which the initial 45-day comment and balloting periods would be followed by shorter comment periods. Another significant change would have removed the requirement for a final ballot to confirm the results of the most recent successful ballot, if the standard drafting team (SDT) felt that no further "substantive changes" were needed. (See *NERC Standards Process Changes Headed for Public Comment*.)

The changes were approved by NERC's Standards Committee in January, following an order issued by the Board of Trustees at its November meeting. Trustee Sue Kelly said in December that the board was trying to address concerns that NERC's "deliberative" standards development process was not keeping up with the increasingly rapid pace of industry change. (See *NERC Board Member Argues for Increased Authority*.)

EPSA Competitive Power Summit

Industry rejected the proposed SPM changes by a significant margin, with 118 votes against and 76 in favor. Some commenters, such as the Northern California Power Agency (NCPA), said the revisions did not adequately address issues of "due process, openness and balance of interests, [which] are already problematic under current SPM rules." NCPA also complained that "SAR [standard authorization request] drafting teams do not always appear to make an effort to resolve SAR objections" as the SPM currently requires.

Commenters also objected specifically to the proposed shortening of later ballot periods, with Andrea Jessup of the Bonneville Power Administration pointing out that "industry subject matter experts are all very busy and … need the full 45 days to allow time for" full review. Jessup said that reducing the time for comments "would likely cause less industry participation" in the process.

Referring to the idea of eliminating the final ballot, the Midwest Reliability Organization's NERC Standards Review Forum said that "only language approved by industry should be considered by the Board of Trustees for approval," a view echoed by multiple commenters. NCPA said it could only agree with the proposal if the SDT makes no changes to the standard that passed the final ballot, explaining that "one person's … idea of 'not making a substantive change' may not always be consistent with entities that voted for the proposal prior to … change."

LS Power Sees Much Work Ahead

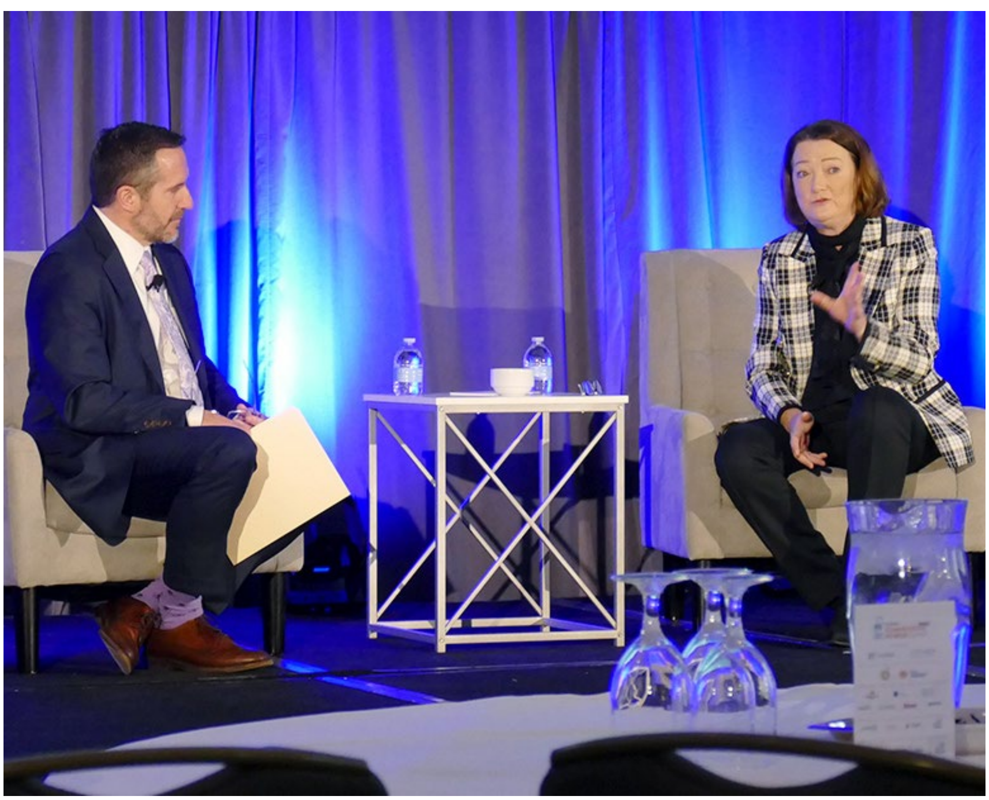
LS Power Generation President Nathan Hanson argued that the industry was just getting started on the transition to cleaner energy.

"If you really step back and think how much progress we've really made facilitating the transition, either on the regulatory basis or even legislatively, I don't think we've really made any ground, and we're basically a year closer to having to manage the issues that are showing up at the grid in California and Texas, or PJM and New England, over the Christmas period," Hanson said.

That changeover needs to happen in a reliable and affordable way to avoid any customer revolts, he added.

"We have legislation and regulations that are going to allow as many renewables into the space as we can. The question is … can you manage the grid when you do that?" Hanson said. "And I would argue we're on the tip of being able to manage it effectively even right now."

Keeping existing plants running is the cheapest way the industry can keep on balancing the grid, but that value is not coming through in many markets, leading to retirements of resources that could help maintain reliability even if they are only run rarely.



EPSA CEO Todd Snitchler (left) and Shell Energy Americas President Carolyn Comer | *© RTO Insider LLC*

Robb also called out the RTOs, saying that they need to revisit their market rules in light of recent issues the industry has faced.

"RTOs really need to revisit their market rules and create some way through market incentives and compensation to synthetically recreate the obligation to serve that guided this industry for such a long period of time," Robb said. "We allow too many decisions to be made based on probabilities, economic returns, the likely scenarios going forward; and those are great. And those work for 99% of the time. It's that 1% though; if we get outside of that, we get into real trouble."

Shell's Comer Endorses the US Approach to Energy Transition

Shell Energy Americas President Carolyn Comer said her firm was well poised to move on the energy agenda and offered praise to the U.S.' "carrot-heavy" policy approach to guiding the energy transition.

The main issue is getting clean sources of energy to scale up because as that work continues, demand is going to grow, with 2 billion more people expected by 2050 and demand for power expected to double globally in that same period, she said. Sometimes the arguments get too simplistic, such as pitting the transition to clean energy against affordability.

"I would argue, actually, if we don't clean up our act and we don't deal with climate change, or we don't tackle the environmental stresses that we're causing, the cost will be greater than the cost of investing in clean technologies in the first place," Comer said.

While there is usually no line item on a power bill, customers are paying for catastrophic climate events from wildfires in the West to the deep freeze that led to days of outages in Texas in 2021, she added.

The Inflation Reduction Act will help the industry move on the transition with a number of "carrots" in the form of tax breaks and other forms of investment in clean technologies.

"I think it's the right way to go because it protects the industrial base at the same time as we actually embark on an accelerated energy transition," Comer said. "And so, I think it's actually kind of leading the world from that perspective."

EPSA Competitive Power Summit

Calpine not Bullish on Geothermal

Calpine has the largest geothermal fleet in the world, a collection of more than 350 wells with a nameplate capacity of about 1,590 MW, which CEO Thad Hill says the company is hoping to expand. But, in a "fireside chat" with EPSA CEO Snitchler, Hill said he does not see geothermal as a game-changer for the energy transition, as building new capacity, specifically closed-loop systems, will be expensive.

At the same time, Hill does see carbon capture as one of the new technologies that will be critical in reaching national and some state-level decarbonization goals, and Calpine hopes to lead the sector as it develops.

Turning to the summit's key theme of reliability, Hill said, the lessons of the February 2021 winter storm in Texas — including the need for better forecasting and gas-electric coordination — have been addressed, but challenges still lie ahead.

"We're in a very different era now. We've got a lot more intermittence. Our traditional definition of what was reliable [is changing]," he said. "Now we have a huge amount of other qualities of risk. We need to talk about reliability from a brand-new standpoint. We're beginning to see that in every single organized market in the country right now."

Compensation for reliability is already being rethought, but further changes may be needed as new intermittent renewable energy comes online, Hill said. "A system … based on how capacity got measured [is not] going to work when you're putting in tens of thousands of megawatts of super-subsidized resources that make sense — almost regardless of the market conditions — to build economically," he said. "So, we've got to think through how we're going to compensate that."

Calpine CEO Thad Hill | © *RTO Insider LLC*

He pointed to PJM's proposals for capacity accreditation as a potential solution, as well as more performance-based compensations schemes now being discussed across the industry.

"I happen to think you should get hammered if you don't perform," he said. "But then you should be able to bid some chance risk into the capacity price you're going to receive in the market."

Hill also sees the increase in corporate clean energy goals and procurement as a positive sign for independent power producers in competitive markets. Innovation on the generation side and the customer side could provide the best way to keep costs down, and he sees rate design, in particular, keeping non-bypassable charges on the low side, as a critical factor.

"I actually think you know, on this construct, we're actually aligned more with our customers, our large customers," he said. "The more non-bypassable charges we have, the less room there is for innovation … whether it's behind the meter, generation [or] storage." ■

Holden Mann contributed to this report.

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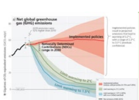

Guterres: G20 Nations Should Commit to Net Zero by 2040

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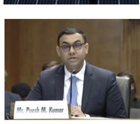
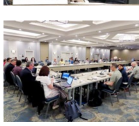


Senate Energy Comm. Ponders Change in Cybersecurity Authorities

ERO Insider



NERC RSTC OKs Standards Projects, Reliability Guidelines

ERO Insider

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EPSA Panel Debates How to Minimize Consumer Pushback as Bills Climb

By K Kaufmann

WASHINGTON — Panelists at the Electric Power Supply Association's (EPSA) Competitive Power Summit last week warned that the clean energy transition could be slowed or side-tracked by consumers if their monthly energy bills continue to rise.

"We're at a crossroads where costs are going nowhere but up," said Christine Tezak, managing director at industry analysts ClearView Energy Partners. "And the question is, are we going to be able to make a value proposition so that the consumer feels they're getting value for the increased cost?

"It's going to be necessary to convince consumers that not only are they getting a lower-carbon alternative, but they're getting increased reliability and better deliverability in that product," Tezak said. "Because it's not just about keeping … the body warm, but it's not having my electricity bill be something that speaks to me every month in a negative way."

From McKinsey to PJM to the International Energy Agency, estimates of the cost of the global energy transition, and the investments needed in the coming years, generally fall within a range of $1 trillion to $4 trillion annually through 2050. But the EPSA panelists had different views on how those figures might play out and what potential pathways to a reliable transition might look like.

Stacey Doré, chief strategy and sustainability officer for Vistra, sees maintaining and expanding competitive power markets as an effective way to keep costs down for consumers, arguing that utility bills in competitive markets are lower than in regulated markets. (See *After a Quarter Century Industry Experts Still Split on Restructuring*.)

"As a competitive retailer, a power generator, our shareholders are taking on a lot of risk [for] these higher costs as opposed to just passing them through to the ratepayer," Doré said.

At the same time, Vistra's investment strategy is centered on shareholder returns, she said. For example, with the acquisition of Energy Harbor, owner of four nuclear reactors in Ohio, Pennsylvania and West Virginia, Vistra now has the second largest portfolio of carbon-free dispatchable power in the country, according to a company *press release*. (See *Vistra Pays more than $3 Billion for Energy Harbor*.)

The company has committed to reducing its greenhouse gas emissions 60% below 2010 levels by 2030.

Representing Wall Street's perspective, Anthony Crowdell, managing director at Mizuho Americas, an investment banking firm, said investors have gotten "very used to very attractive earnings growth rates" from regulated electric utilities, which receive guaranteed rates of return on their capital spending. Investors' concerns now turn on the likelihood that inflation and higher electricity bills will trigger regulatory pushback — limiting rates of return — and whether "what utilities have promised in the past, they may not be able to deliver," Crowdell said.

But most consumers don't understand or care about competitive versus regulated markets or the skittishness of equity investors, said David Springe, executive director of the National Association of State Utility Consumer Advocates (NASUCA).

"They just know at the end of the day, the bills are going up," Springe said. "It's the same kilowatt-hours that were turning the lights on 20 years ago and turning the lights on 10 years ago and turning the lights on last week. It's the same kilowatt-hour; it just costs 100% or 200% more than it used to. You're not going

A panel discussion on who pays for the U.S. energy transition at EPSA's Competitive Power Summit: (from left) Katherine Blunt, *The Wall Street Journal* (moderator); Stacey Dore, Vistra; Christine Tezak, ClearView Energy Partners; Anthony Crowdell, Mizuho Americas; and David Springe, NASUCA. | *© RTO Insider LLC* to explain that to customers, and you will see political pushback. …

"The same people that just arbitrarily say we're going to have 100% [electric vehicles] by 2035 are the same people that will arbitrarily tell utilities to stop raising rates," he said.

Defining 'Affordability'

Exactly how to balance the conflicting priorities of the transition has become an ongoing conversation within the energy industry and at conferences like the Competitive Power Summit. EPSA's membership is predominately independent power producers who advocate for competitive wholesale power markets.

Climate advocates point to the mounting physical and financial impacts of extreme weather events, as well as the new federal subsidies for clean power in the Inflation Reduction Act as clear signs for acceleration. Releasing the U.N.'s 6th Assessment Report Synthesis on climate change on March 20, Secretary General António Guterres called for the largest industrialized nations of the world to phase out all coal-fired generation by 2030. (See *Guterres: G20 Nations Should Commit to Net Zero by 2040*.)

But industry insiders like Doré argue that reliability and cost should determine the pace of the transition. Wholesale power markets have a vital role to play, sending appropriate price signals to advance policy objectives while minimizing price increases for consumers, she said.

Pace is "the key to the transition," Doré said. "Our markets need to send the right price signals to build the kind of generation that we need."

The war in Ukraine, for example, has opened questions about the need for new gas-fired generation, Doré said. "We look all the time at whether it's economic to build new gas plants. In most markets today, it's not because the investment signals are not there."

She called for "an honest conversation about what is the right pace. What is the all-of-the-above strategy [for] getting eventually to deep decarbonization? I think we have to talk about investment signals. We have to talk about demand response. We have to talk about all the different methods of getting there. But we also have to be realistic about what the goals are," Doré said.

Springe countered that the focus on building big projects to push the transition forward could be counterproductive, given the long lead times and resulting high costs needed to permit and construct such installations.

"I worry that there's sort of a focus on big and fancy, and where the money and incentives should be is local, close: demand response, energy efficiency, solar, batteries; things that are near, because we can build those. So, I worry that we're going to lose speed, in a sense, chasing the big and really miss out on an opportunity to accomplish the small," he said.

Another part of the problem is that few states or regulatory commissions have a legal or structural definition of "affordability," Springe said. While not offering a definition of his own, he called for "a very specific process to define what [affordability] is, whether you have it in your statutes or you don't," he said. The process also needs to be part of project planning, Springe said, "not after they've built an asset and have come to bring it and integrate it" into a rate base.

"You've got to define a metric, and you've got to do it up front," he said. "What is it? How do you enforce it? … And how many things can we actually build in the state in that affordability metric?"

How We Buy Electricity

Tezak took a more market-based approach to the issue of ordering priorities, noting first that the emerging technologies that will be needed for long-term decarbonization "require time to be demonstrated, for you have to have a couple of [projects] get online before anybody makes money." A "real portfolio concept" for procuring capacity could incorporate "a lot of character attributes," she said.

One way forward could be "rebundling some of the capacity for long-term procurement with [clean energy] development … and coming to grips with what that capacity is," she said. "The capacity market doesn't have to be limited to the auction. I think to build faith back into markets, we may have to step away from defining them solely as a terrifically functioning auction because it isn't how you buy anything else, and it's not how we're buying energy for this transition," Tezak said.

"We're talking about [power purchase agreements]; … we're talking about interconnection; we're talking about all that stuff, and the perfect, well functioning auction that we had for a couple of years seems to exist in a parallel universe," she said. "Is it time to take the plunge of talking about not doing tweaks but doing major changes and what that means? And that's hard because investors don't like uncertainty and many of them … really dislike change."

But Doré doesn't think the markets need fixing *per se*. "The problem is we're not allowing the markets to function the way that they were designed to function," she said. "Things like market caps or trying to adjust capacity accreditation in a way that disadvantages dispatchable generation are interferences in the market that are going to scare away investors. …

"The problem is we have so many changes in our markets every time the legislature meets or every time the commission meets or every time FERC or one of the ISOs meet. … That just injects a lot of uncertainty for investors," she said. "So, the ground is always shaking beneath you a bit."

Mizuho's Crowdell agreed that investors are looking for stability in markets across a range of variables, such as cost recovery after extreme weather events. Should shareholders or consumers pay, and who decides? Securitizing costs after an extreme weather event could reduce impact on customers' bills, but in the long term, the customers who end up paying 10 or 20 years down the road weren't even around when the costs were incurred, he said.

"When you think about the regional market, their concerns are different that the actual individual state," which could also be different from those of individual legislators or regulators, he said. And legislative turnover in states continues to accelerate.

"We've seen much quicker changes in the state house," he said, with the projects and policies of one administration being rolled back by a new set of players. "The equity holders are trying to balance [to] see where it's going."

But the panel circled back to the core issue of whether consumers might reject any further rate increases for clean energy. While consumer advocates are often uncomfortable with such questions, Springe said, "we really need to have a much broader discussion around what the price is going to be and figuring out how to match that up with when assets or resources appear."

The special rates some utilities have introduced that encourage charging EVs at specific times of the day are one example of the kinds of rate design that will be needed going forward, Springe said. Doré agreed, pointing to Vistra's *Free Nights and Solar Days* pricing plan in Texas that "encourages customers to use energy at the time of day when there's less burden on the system."

"Those kinds of plans are not possible unless you have a robust, competitive retail market," she said. "If you want customer innovation, you've got to have competition." ■

EPSA Competitive Power Summit

NERC Balks at Expansion of Cyber Rules

EPSA Panel Discusses Foreign, Domestic Threats

By Rich Heidorn Jr.

WASHINGTON — NERC will not support expanding physical security standards to all bulk power system transmission assets when it files comments with FERC next month, a senior official told the Electric Power Supply Association (EPSA) last week.

FERC's existing physical security reliability standard (CIP-014-3) requires transmission owners to perform periodic assessments to identify transmission stations and substations whose loss or damage could cause cascading outages.

In December, FERC ordered NERC to report on the effectiveness of the existing standards and determine whether a minimum level of protections should be required for all BPS transmission stations, substations and primary control centers (*RD23-2*). The commission acted following the Dec. 3 gunfire attack on two Duke Energy (NYSE:DUK) substations in North Carolina, which left 45,000 customers without power for as long as four days. NERC's response is due in mid-April. (See *FERC Orders NERC Review on Physical Security*.)

"The easy answer will be apply everything [to] every station … Just protect them," NERC Senior Vice President Manny Cancel said during a panel discussion at EPSA's Competitive Power Summit March 21. "That really is not very prudent. It doesn't make any sense at the end of the day to drive up costs without really buying down risk. So [NERC will propose] a much more risk-based approach [with a] discussion about the sort of no-regrets moves to make. And it's not just physical protection, right? It could be everything from designing the grid differently. It could be the introduction of renewables and battery storage. It could be a bunch of those."

RTO Insider Editor Rich Heidorn Jr. (left) moderates a panel on cyber and physical security with (from left) FBI Special Agent John J. Rovinski Jr.; Manny Cancel, CEO of the E-ISAC; Mara Winn, deputy director for preparedness, policy and risk analysis for the Department of Energy's Office of Cybersecurity, Energy Security, and Emergency Response (CESER); and former New Jersey regulator Richard S. Mroz, an adviser to Protect Our Power | © *RTO Insider LLC*

Advance Planning Crucial

Cancel's fellow panelists agreed on the need to balance costs against risks. They said the most cost-effective protections are those planned in advance.

"Bolting it on [afterward] is not the way that we want to do security," said Mara Winn, deputy director for preparedness, policy and risk analysis for the Department of Energy's Office of Cybersecurity, Energy Security, and Emergency Response (CESER). "'Secure by design' is something that we take very seriously."

That includes vetting of suppliers. "It is a lot better to know that you've done your due diligence, that you … are buying from suppliers that you can trust," she said.

"You can't bolt down every system, so you have to pick and choose," said John J. Rovinski Jr., supervisory special agent in the FBI's Cyber Division. "Just obstructing the view of things and knowing your architecture is key. … It doesn't have to be a [large] investment. CISA [the Department of Homeland Security's Cybersecurity and Infrastructure Security Agency] just put out a product on their website last month, specifically talking about hardening power substations, and listed out a number of different things that are not very expensive to do. Just maintaining a fence. Having signage. Making sure there's no vegetation near those fences offers you better sight lines for your closed-circuit TVs. It's not very expensive to hire someone to come and trim your bushes back."

"It can't be gold-plated. It's got to be prudent," said former New Jersey regulator Richard S. Mroz, an adviser to *Protect Our Power*, an organization that supports efforts to strengthen the grid. "But it *is* prudent to make these investments … whether it's in cybersecurity or physical security, because the alternative — the cost of not doing it — is worse."

'Copycats'

Cancel is also CEO of the Electricity Information Sharing and Analysis Center (E-ISAC), which saw a spike in physical security incidents in the presidential election year of 2020 and in the mid-term election year of 2022. Most incidents involved petty thefts or vandalism, and only 3% of such incidents resulted in impacts to the grid, he said.

Although small groups of *neo-Nazi* and *white supremacist* sympathizers have been accused in planned attacks on grid assets, there is no evidence of central planning of such attacks, Cancel and Rovinski said. (See *Feds Charge Two in Alleged Conspiracy to Attack BGE Grid*.)

In most incidents, Cancel said, "we don't know a lot about attribution, because, as you know, there hasn't been many apprehensions."

But, he added, "When you look at all these extremist groups, or groups that are driven by a particular ideology, it is a consistent arrow in their quiver: That is attacking critical infrastructure, whether it's electricity or some other critical infrastructure sector. That's part of their plan."

As a result, Cancel said, the E-ISAC's seventh *GridEx* exercise on Nov. 14-15 will "have a big focus on physical security."

"The grid itself is a natural target," said Rovinski, "just because it's visible, a kind of community service that is locally available — you don't have to travel far.

"The increase in attacks increases the chatter among the groups who look at the news coverage, because media coverage, obviously, invites copycats," he added. "They've seen power being taken down for 60,000 people. [They think] 'Oh, that creates an attack that gets our message out, that puts us to the forefront.'"

Transatlantic Cooperation

The panelists also agreed that the U.S. has improved cooperation with its European allies in response to fears that Russia might launch cyberattacks to dissuade them from coming to the aid of Ukraine.

"As far back as probably October of 2021, before the invasion actually occurred, we were getting briefings from our government partners both at CISA and at DOE," said Cancel.

"We had gotten the sector together to say, look … this threat is real, here are the potential things that could happen [and] made everybody revisit what happened with Ukraine in 2015 and 2016, where Russia actually did disrupt electricity infrastructure there."

CISA and DOE *warned* of the need to monitor for malicious software called Pipedream with the ability to disrupt critical infrastructure.

"We came together in unity," Winn said of the U.S. and its allies. "I think that's a fantastic outcome of a challenging situation."

Now, she said, the question is, "What do we need to do to sustain efforts to make sure that we don't lose all of that engagement? To make sure that … the partnership on analyzing and understanding threats continue."

Cancel said officials also are focused on the threat from China, which he said has "very sophisticated capabilities that are similar — and in some cases may exceed — [Russia].

"We continue to see attempts to survey networks here in the United States. And what the Chinese are very good at doing is looking for vulnerabilities; looking for holes in networks, so they can get in and introduce malware or just, you know, poke around and see what they can steal. It's very focused on espionage surveillance." ■

FERC/Federal News

FERC Urged to Close 'Regulatory Gap' on Tx Costs

TOs Argue Existing Rules Are Up to the Task

James Downing

State regulators, environmental groups and ratepayers urged FERC last week to control growing transmission costs by increasing oversight of "local" projects, limiting the use of formula rates and other measures. Transmission owners defended their spending and said FERC's existing oversight processes under Order 890 are sufficient.

FERC solicited the stakeholders' comments after it held a technical conference on containing transmission costs last October (AD22-8, AD21-15). (See *Transmission Owners, RTOs Defend Planning, Cost Control Practices*.)

The Illinois Commerce Commission and New Jersey Board of Public Utilities filed joint comments noting that both states have aggressive policies to decarbonize their power systems that will require significant transmission expansion. But that does not mean transmission should be built with little to no scrutiny, which the regulators said has been happening with "supplemental projects" in PJM.

Supplemental projects (called "asset management" projects under Order 890) represented 55% of the cost of transmission entering service from 2017 to 2021, ICC and BPU said. Spending on supplemental projects totaled $13.7 billion in that five-year period, compared to just $7.1 billion in the 19 years between 1998 and 2016.

"The need for new and stronger transmission, weighed against transmission's rising costs, potential novel technological alternative solutions, and an inability to access underlying data, puts stakeholders — state commissions in particular — in a difficult situation with respect to assessing the efficiency and cost-effectiveness of proposed transmission plans," the BPU and ICC said. "The majority of regional transmission owner stakeholders lack the resources and information necessary to make such determinations."

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An independent transmission monitor, as initially suggested in FERC's advanced Notice of Proposed Rulemaking on transmission, could determine how well planning processes are working and determine whether local projects' needs might be addressed more efficiently through a regionally planned project, the states said.

"We believe a regulatory gap exists," the Ohio Public Utility Commission's Federal Energy Advocate told FERC. "Too many transmission projects are not receiving sufficient regulatory scrutiny to ensure regulators and the public that, at least with regard to local (i.e., supplemental) projects, the regional transmission systems are being built in a cost-effective manner."

States are hampered in overseeing such projects in PJM because even though they are limited to a specific zone, such zones often cross state lines — as do three of the four that make up Ohio. Even if the PUC stepped up its oversight, Ohio ratepayers would still be faced with costs allocated from projects that fall outside its jurisdiction, the advocate said.

The American Public Power Association also called for FERC to address locally planned projects.

"Among other potential problems, the magnitude of investment in locally planned projects suggests that transmission owners in some regions may be directing investment to such projects, with the result that potentially more efficient or cost-effective facilities are not considered," APPA said.

But the problems vary by region and even between neighboring transmission owners so FERC should be flexible if it moves forward with any rule changes, the public power trade group said.

Advanced Energy United said local projects lead to fewer benefits than the major regional lines that are needed to help decarbonize the power system.

FERC "should aim to ensure more effective oversight of local transmission projects and more efficient regional and interregional transmission planning such that regional projects and/or non-wires alternatives and grid-enhancing technologies are selected over local projects when doing so would increase the benefits of transmission buildout while reducing total transmission costs," said AEU.

FERC/Federal News

More information sharing about such projects would help ensure that the money is being spent prudently and aid states in assessing such projects, AEU added. Setting up independent transmission monitors could help deal with the information asymmetry by providing independent analysis for all stakeholders, it said.

A joint filing of groups calling themselves the "Electricity Customer Alliance," included several state consumer advocates from PJM, the Citizens Utility Board of Illinois, Electricity Consumers Resource Counsel, Public Citizen and the R Street Institute.

"Transmission developers have ample access to capital and spend over $20 billion per year on transmission in the United States," the groups said. "Unfortunately, billions of dollars are misallocated annually, eroding net benefits to consumers and suppressing development of cleaner and lower-cost generation."

FERC's regional planning NOPR proposed pulling back on transmission competition by giving utilities the right of first refusal over transmission projects if they team up with another firm. But the groups said that would not bring their dollars out of the local process and into the regional planning process.

The Environmental Defense Fund, Natural Resources Defense Council, Sustainable FERC Project, Sierra Club and other environmental groups filed joint comments saying the current lack of oversight means FERC cannot ensure that transmission rates are just and reasonable.

"The current Order No. 890 requirements are insufficient to ensure a transparent process where stakeholders have a meaningful opportunity to examine system needs, evaluate public utility transmission providers' proposed solutions, or propose potential solutions that can more effectively address these needs," the groups said. "In practice, these requirements are treated like suggestions that are neither binding nor sufficiently detailed to elicit proper behavior from public utility transmission providers."

Independent power producers NRG Energy (NYSE: NRG) and LS Power argued that while spending on transmission has been on the rise, it has not been for the major projects needed to transform the grid. In addition to developing generation, LS is active in competitive transmission development. NRG said the 5.5 million customers of its retail power business have seen their delivery charges rising in recent years.

"By removing the pass-through regulation that has come to characterize formula ratemaking in this field from its application to certain transmission rate base, the commission can return to the basic principles of sound utility regulation while achieving the public policy goals that animate much of its recent transmission rulemaking activities," NRG and LS said.

They said FERC should put all projects at 100 kV and above into regional planning processes, a position LS Power has had for years.

Formula rates allow transmission owners to put new transmission investment into their ratebase with a presumption that it is just and reasonable. FERC could limit the type of lines that are put into formula rates to those that face competition, or additional regulatory oversight, or could even eliminate the practice altogether, NRG and LS said.

Utilities Say Local Spending is Justified

Formula rates are transparent and offer oversight, along with the benefits of administrative efficiency and allow for timely recovery of costs, said the Edison Electric Institute.

If any regulatory gaps exist, EEI said, the planning processes vary so much by region that FERC should not force universal fixes. Order 890's rules for supplemental projects already offer sufficient transparency, it said.

The issue of smaller lines taking precedent has often come up in PJM, but Exelon told FERC there is good reason for the recent increase in spending in supplemental projects there.

"During the 2010s, PJM faced historically low load growth and had just experienced a build cycle of natural gas units, which had the effect of moving significant new, low-cost generation closer to load centers, reducing congestion," Exelon said. "While these factors moderated the need for regional projects, during this period PJM identified, and PJM transmission owners developed, more than $20 billion in regional projects."

Local projects needed investment in the same period as many lines reached the end of their useful lives and others needed maintenance, said Exelon (NASDAQ:EXC).

FERC should focus on the other changes it has considered — including the shift to forward-looking, scenario-based planning and first-ready/first-served queue processing — because the regulatory changes implied by its request for comments would amount to "experimentation" and might only delay needed investment in transmission, the company said.

American Electric Power (NASDAQ:AEP) agreed with Exelon that age is a major factor in rising transmission spending, saying 27% of its transformers and 10% of its circuit breakers are expected to exceed their life expectancy in the next 10 years.

"This reveals the simple fact that assets, some of which exceed 100 years old, have now reached the end of their useful life and need to be replaced to ensure the continuing reliability and resilience of the system," AEP said.

AEP joined other transmission owners in questioning whether independent transmission monitors are needed, warning they could delay the transmission buildout without producing any real benefits.

The New York Transmission Owners do not want FERC to impose any national fixes because they could put a wrench in their efforts working with the state and others to implement the Climate Leadership and Community Protection Act that requires the state to have net zero emissions by mid-century. Because NYISO is in a single state, the local projects that have generated controversy in PJM are highly transparent there and regularly updated publicly with NYISO, the transmission owners said.

RTOs Weigh In

ISO-NE told FERC that its states have already asked for some reforms on "asset condition projects," and its stakeholders should be allowed to work on that process.

Such projects are like PJM's supplemental lines and generally fall under transmission owners' responsibilities, but in New England projects above $5 million have to go the ISO's Planning Advisory Committee.

PJM filed comments saying that FERC has found its supplemental transmission process provides enough transparency to stakeholders and reaffirmed that when the same rules were extended to end-of-life projects.

All stakeholders, including state regulators, can ask questions during its "Attachment M3" process for local planning.

"PJM currently has processes in place pursuant to which a PJM TO or incumbent developer constructing either a [regional] baseline project approved by the PJM Board of Managers or an Attachment M-3 Project provides reports to PJM, which allows PJM to track the project's scope, schedule and any cost increases," the RTO said. ■

FERC/Federal News

Republicans Opening Offer on Permitting is Missing Electric Tx

By James Downing

House Republicans this month are moving a package aimed at changing the country's energy permitting processes, but it lacks changes to a key area backed by Democrats and many in the power industry: electric transmission.

House Speaker Kevin McCarthy (R-Calif.) introduced *HR 1*, the Lower Energy Costs Act, which includes a package of reforms to the National Environmental Policy Act and is largely aimed at oil and gas production and mining.

McCarthy gave the bill the number HR 1 because it is the House GOP's top priority this Congress, he said earlier this month. The Committee on Rules is already taking amendments on the package and could move the bill onto the floor this week.

"Every time we need a pipeline, road or dam, an average of almost five years and millions of dollars in costs get added to the project to comply with Washington's permitting process," McCarthy said. "That's too long. We can streamline permitting and still protect the environment. That's a goal worthy of the number 1."

American Petroleum Institute President Mike Sommers wrote a letter to House leaders from both parties in favor of the Republican package.

"One particular focus of API and our members is enacting serious, bipartisan permitting reform," Sommers said. "Too many projects have been scuttled because of onerous regulations and uncertainty. The delays and denials of permits, stemming from lengthy regulatory reviews and drawn-out judicial proceedings, have stifled needed investments and increased costs."

American Clean Power said HR 1 includes "important provisions and reforms" that will speed up the deployment of clean energy in the U.S.

"Failure to enact critical permitting reforms and lift barriers that are hindering our ability to build much-needed transmission puts an estimated 150,000 clean energy jobs at risk," ACP President Jason Grumet said in a statement. "We look forward to working with Congress to build on this important effort."

The package is full of ideas Republicans have been debating in recent Congresses and represents what that caucus wants to see happen on energy, said former FERC Chairman and Hogan Lovells Senior Adviser Neil Chatterjee. The bill is likely to pass the House with Republican support and maybe a few Democrats too.

"It's also an opening offer to negotiation with the Senate," Chatterjee said in an interview. "And I think, ultimately, to the extent that something gets done specifically on permitting reform, I think the Senate is going to drive that. So, we just have to see what can get the votes in the Senate and also get a majority in the House."

Any permitting reform that passes both chambers is likely to be narrower and will require some tradeoffs between Democrats who want to focus on expanding clean energy and Republicans who favor fossil fuels. Chatterjee said that partisan split does not make sense, but recent events have only solidified it.

'Easier Said Than Done'

The Inflation Reduction Act (IRA) included a number of provisions that Chatterjee supported as a Republican, but he was always critical of the fact that Democrats passed it without Republican support.

"My frustration was that it was done in a partisan manner," Chatterjee said. "This is what this is, what I was concerned about, is that to the extent it became a political football, you wouldn't get a whole lot of cooperation to make sure it's implemented properly."

Republicans did not include any provisions aimed at transmission in HR 1 because it would only help to implement the IRA and they have no incentive to help Democratic policy become a reality, he added.

"I think there is some willingness on the Republican side in both chambers to pursue transmission as part of a bipartisan bill," Grid Strategies President Rob Gramlich said in an interview. "But I don't think people are seeing HR 1 as really the bipartisan effort that includes transmission."

Any bipartisan bill would have to include provisions that speed up the pace of transmission development significantly, and many climate hawk Democrats will have to decide whether any deals they cut lead to long-term emissions cuts, Gramlich said.

"I think there's a lot of interest in more of a bright line authority for FERC on their permitting, something similar to Sen. [Sheldon] Whitehouse's *SITE Act*, which has a 1,000-MW bright line," said Gramlich.

Whitehouse (D-R.I.) in the last Congress introduced the Streamlining Interstate Transmission of Electricity Act, which would give FERC new siting authority for large, interstate lines.

FERC and DOE currently split some backstop siting authority, but that process requires NEPA reviews at both agencies and can take a long time. The arrangement has been in place since 2005 and has never been used to successfully site a transmission line.

Sen. Kevin Cramer (R-N.D.) is a former state regulator who knows the transmission issues well and will likely be key to getting Republican support for any reforms in that area, Chatterjee said. But there is still a question of whether FERC would have the appetite to use that authority.

"I've heard both former Democratic and Republican commissioners say this: that even if FERC had enhanced authority in this area, I think they'd be reluctant to do it," Chatterjee said. "It's just easier said than done to roll over the states on something this sensitive and this complicated." ■

The U.S. Capitol Building | *David Maiolo, CC BY-SA-3.0, via Wikimedia*

FERC/Federal News

Webinar Wades into Push to Revise US Permitting Rules

By James Downing

The U.S. must change its permitting processes to deploy the $2 trillion allocated for energy in last year's industrial policy bills and ensure the emissions reductions needed to *avoid* the worst impacts of climate change, speakers said during a webinar hosted by OurEnergyPolicy on Wednesday.

Rep. Pete Stauber (R-Minn.), whose Northeast Minnesota district is home to the nation's biggest reserves of key clean energy industry minerals such as nickel, cobalt and platinum, said a proposal to speed up approval of mining permits has made it into House Republican bill *HR 1*, which is expected to move to a floor vote as early as this week. (See related story, *Republicans' Opening Offer on Permitting is Missing Electric Tx*.)

"We have yet to move earth at all on those resources," Stauber said. "In fact, we have one mining proposal on year 20 of permitting and litigation. Think about that: a proposal to mine the minerals needed for clean energy is being held up for 20 years."

Without tapping those resources and many others, renewable energy goals will not be attained, he said.

"We are dealing with an incredibly complex permitting landscape that's influenced by an extraordinarily dynamic regulatory landscape that is — across federal, state [and] local levels — often uncoordinated," said Karen Hanley, senior vice president at the Permitting Institute. "And when we're talking about 'rising tides lift all boats,' we're looking for good governance in the permitting process itself."

Much of the conversation on the Hill has been dominated by the National Environmental Policy Act, which Hanley noted is just one of 65 federal laws and regulations that impact permitting, on top of many more rules from the states and local government.

"Where policy comes into play, we consider that to be a separate discussion; the process itself should not be used subjectively to pick winners and losers," Hanley said.

The permitting process must weigh the benefits of an infrastructure project against its impact on the area where it is built, other speakers said.

"It's all just a matter of trade-offs," said Paul Phifer, director of permitting and development at Attentive Energy. "I mean, all permitting to me is an expression of our values. So, it's an expression of risk management."

Phifer's firm is a subsidiary of French oil major TotalEnergies, which is developing an offshore wind project off the coast of New York. It would make sense for Congress to change the permitting laws to reflect some of the new tradeoffs faced by energy development now, he argued.

Setting the Tone

Much of the conversation on rule changes has focused on "categorical exclusions" that would give energy projects of preferred types or in specific areas an easy path through the process if they have limited environmental impacts, said Hanley. The Coast Guard must review some offshore projects, but it has a checklist it can apply to execute such categorical exclusions that ensure it has double checked that its oversight is not needed for specific projects, she added.

Accelerating the permitting process does not necessarily require a raft of new laws but rather Congress being clearer about how they are to be implemented, Phifer said.

"That's the kind of thing that sets the tone that I would say that filters down … through the federal agencies even to the states, as opposed to tweaking and making minor regulatory revisions across the 65 laws that Karen mentioned," Phifer said.

Getting any changes through Congress this year will require bipartisanship, with both chambers closely divided and controlled by different parties.

"I think there's interest on both sides of the aisle, in particular, in long linear projects," Hanley said. "I think there's a recognition that where our energy needs are, isn't necessarily the same places where the sources are, or the generation can be."

Communities located between areas with energy resources and bigger sources of demand must often deal with projects that provide them little benefit, which brings up many complexities.

The issue of permitting has been debated for years, and Hanley expects lawmakers to insert many of their older proposals into the package. But she thinks there is opportunity to move forward on a package that addresses "fundamental process corrections" that do not eliminate necessary environmental protections.

"Obviously, all industries have their own little pet asks that they would like to see included in a package like that," said Emily Wong, American Petroleum Institute's director of federal relations. "But I think it's been pretty clear from our discussion today, that we've all identified a lot of the same big-picture issues. And it's certainly our hope, at API at least, that there's enough agreement there for us to see something move across the finish line." ■

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CAISO/West News

Calif. Governor Seeks Central Procurement Authority

State Legislative Analyst Questions the Impact on Energy Markets, Ratepayers

By Hudson Sangree

The office of California Gov. Gavin Newsom has proposed legislation that would establish a central procurement authority to ensure the state has sufficient electricity resources to avoid shortfalls as it struggles with extreme heat, tight supply and a changing resource mix across the West.

The proposal is contained in budget *trailer bill* language that follows Newsom's fiscal year 2023/24 budget released in January. No lawmaker has yet signed on to carry the bill in the current legislative session.

The governor's proposal would give the California Public Utilities Commission (CPUC) the option to name the state Department of Water Resources (DWR) or an investor-owned utility to procure energy for the state's load-serving entities, including public utilities and community choice aggregators.

"For California to achieve its long-term greenhouse gas emission reduction goals, while maintaining a reliable electrical system and providing customers with greater choice in electricity retail providers, the state must establish a new central procurement function within the [DWR] that enables the development of a more diverse portfolio of renewable and zero-carbon energy resources," it says.

The state has directed investor-owned utilities to procure for other LSEs in the past, but DWR has not performed that function. The governor's legislative language would authorize it to do so if called upon by the CPUC.

The department's State Water Project is a major producer of electricity through its hydroelectric projects and the state's single largest consumer of electricity, which it uses to operate pumping plants that deliver water throughout the state.

Under the proposal, DWR could issue bonds and recover costs through ratepayer charges approved by the CPUC as long as the charges "[do] not unreasonably increase costs to customers … compared with the procurement of diverse clean energy resources by an electrical corporation."

DWR would have to conduct a competitive procurement process and "prioritize investments that do not compete with the procurement of diverse clean energy resources already planned for development and disclosed by load-serving entities or local publicly owned electric utilities."

LAO Report

In a March 10 *report* on the governor's proposal, the state Legislative Analyst's Office says that "according to the administration, the DWR procurement is intended to be for long-lead-time resources such as offshore wind, geothermal, and long duration storage. The proposed statutory changes, however, do not explicitly limit this procurement option to those types of resources."

"DWR would utilize its new Strategic Reliability Reserve office and staff to manage the procurement," the LAO report says.

The department administers the state's Electricity Supply Strategic Reliability Reserve Program (ESSRRP), a $5.2 billion fund sought by Newsom in last year's budget and enacted in June to pay for new generation and storage, to keep older natural gas plants online and to provide emergency backup generation through DWR. (See *California to Pass Sweeping Energy Policy Changes*.)

California has experienced blackouts and near misses the past three summers as it tries to shift its resource mix from fossil fuels to renewable power amid extreme heat, wildfires, drought and strained supply in neighboring states.

Another component of the governor's legislative proposal is a requirement that load-serving entities pay for failing to obtain sufficient resources to meet demand by making payments to the strategic reserve fund. The move is intended to "discourage LSEs from over-relying" on the ESSRRP, the report says.

"The state would assess a payment if an LSE does not meet its reliability obligations in a month when the state had to access the ESSRRP," it says. "Specifically, the payment would be based on a calculation that factors in the cost of the energy resource provided by the ESSRRP and the LSE's deficiency in meeting its monthly resource adequacy or planning reserve requirements. The payments would be calculated by the CPUC and the California Energy Commission."

The payments would be in addition to fines for resource inadequacy imposed by the CPUC.

Questions for Lawmakers

The LAO report proposes questions for lawmakers to consider when weighing the governor's proposal, including the potential impact on ratepayers of adding DWR procurement costs to their already-high electricity bills.

It also questions the market effects of central procurement by DWR.

"The current market for energy resources is strained, with a large number of LSEs competing for a relatively small pool of projects that often will take years to develop," it says. "How the entrance of DWR — a large, well resourced entity with the backing of the state — would influence the market for new energy resources is unclear."

The report also questions whether the state needs new central procurement authority or whether current resource planning processes and the ability of IOUs to procure for other LSEs is enough.

Having DWR in charge of long-lead time resources poses risks, the report says.

"The administration has expressed concerns that LSEs might be hesitant to procure large, long-lead-time resources because of their high cost and risk as newer technologies," it says. "The Governor's proposal to have the state pursue procuring these resources instead essentially shifts this risk from the privately owned utilities (and their investors) to ratepayers and taxpayers. While this could help facilitate the development of these important resources, additional information is needed about the types of risks involved and their magnitude for the Legislature to determine if they are worth the potential benefits."

Finally, the LAO asks whether the energy policy changes should be considered as part of the budget process.

"The Governor's proposals represent significant policy changes for the state, and they do not have a particularly strong nexus with the budget," the report says. "The Legislature will want to consider the most appropriate venue for discussing and deliberating these proposed changes. For example, the Legislature could consider these proposals through the policy process, rather than as part of the budget process." ■

CAISO/West News

CAISO Board Approves Summer Readiness Measures

Extends Battery Charge Requirement, Updates Backstop Procurement Rules

By Hudson Sangree

CAISO's Board of Governors on Thursday approved measures to help ensure summer reliability, including extending for a third year a requirement that utility-scale storage batteries maintain a minimum state of charge during critical conditions.

The requirement "applies during very limited circumstances where we experience the most constrained conditions on the system," such as during an extreme heat wave last September that brought CAISO to the brink of ordering rolling blackouts, said Anna McKenna, the ISO's vice president of market policy and performance. (See *California Runs on Fumes but Avoids Blackouts*.)

In a memo to the board, McKenna and other CAISO staff members said the storage constraint "mitigates the risk storage resources may be unable to meet day-ahead discharge schedules in the real-time market because they were either insufficiently charged or discharged prematurely, leaving them unable to meet their day-ahead schedules for later hours when their energy may be essential to maintain reliability."

The requirement was intended to be temporary when it was adopted in April 2021, following the rolling blackouts of August 2020. CAISO decided to extend it despite opposition from some stakeholders, primarily storage operators who said it puts them at a disadvantage when demand and prices are highest.

The ISO intends to replace the minimum state of charge constraint with a "more comprehensive set of tools" that the Board of Governors approved in December, but the software for its planned system upgrade is not yet ready, the staff memo said.

"These more comprehensive sets of tools, when implemented, will provide ISO operators with enhanced state of charge visibility and control via exceptional dispatch functionality," it said. "These enhancements also provide opportunity cost compensation for resources that are exceptionally dispatched to hold state of charge."

CAISO management had originally proposed extending the minimum state of charge requirement through September 2024 to allow for unanticipated delays in software development. But it pulled back on that plan because of stakeholder concerns and set Sept. 30, 2023, as the sunset date to ensure it "expires even in the event of implementation delays," the memo said.

Capacity Procurement Mechanism

The Board of Governors also approved updates to the ISO's capacity procurement mechanism (CPM) that it uses to purchase electricity to head off shortfalls during "significant events" such as summer heat waves.

The changes are "limited but necessary for us to access capacity over the summer that may be needed to backstop should we be not sufficient with the resource adequacy capacity that we have," McKenna told the board Thursday.

CAISO ran into problems using its "backstop" CPM to find and procure capacity during summer heat waves in 2020 and 2021, partly because of its own rules, a *staff memo* said.

To fix those issues, CAISO management proposed four operational improvements, including two changes to its rules to help the ISO buy electricity that is "not contracted for during a significant event," a *staff memo* said.

One change would let the ISO adjust the volume in megawatts of CPM resources "if the designated capacity already is committed and shown to the ISO as resource adequacy capacity."

Another gives resource scheduling coordinators flexibility to designate resources for a significant-event CPM for less than 30 days, which has been the minimum term.

"Because of this rule, a resource scheduling coordinator may have to reject a mid-month significant event CPM designation because the designated capacity has an existing commitment or is unavailable for the following month," the memo said. "This existing minimum term rule has prevented the ISO from accessing immediately needed and immediately available capacity." ■

Batteries need to be available during summer shortfalls, CAISO said. | *Southern California Edison*

CAISO/West News

WECC Report Reviews State of the Western Interconnection

By Robert Mullin

Among the topics covered by WECC's State of the Interconnection (SOTI) *report* released Friday, one subject stands out for its immediacy: the impact of extreme natural events on the Western grid.

WECC organizes the annual report to highlight its stakeholder-selected reliability risk priorities, which currently include cybersecurity, natural events, resource adequacy, and the impact of changing resources and customer loads on the bulk power system (BPS).

And while growing cybersecurity risks get play across the NERC-led ERO Enterprise, the SOTI makes clear that climate threats are still paramount in the Western Interconnection.

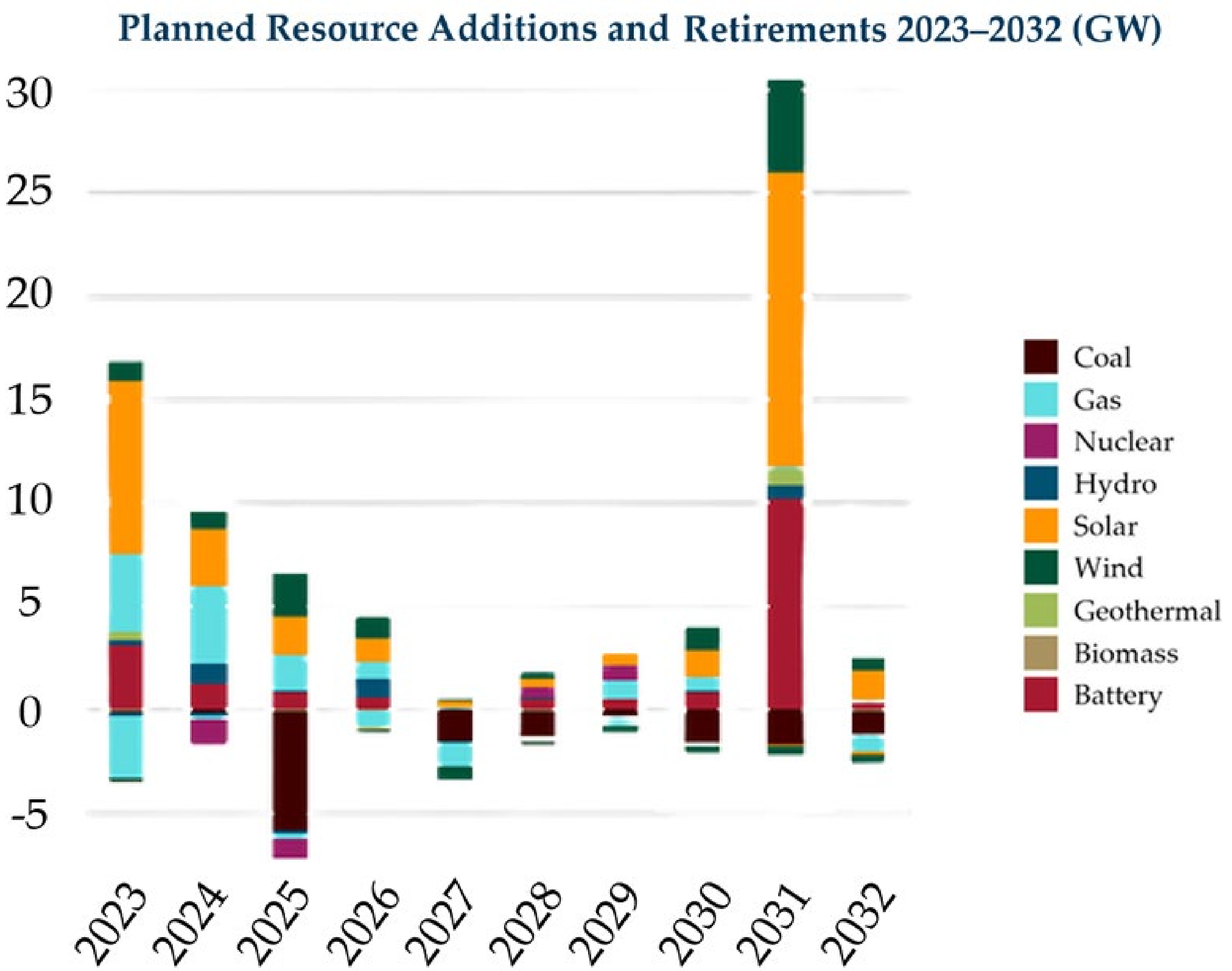
"Last year, the West experienced extreme weather ranging from heat waves and dry spells to extreme winter storms and atmospheric rivers. The frequency, duration and seasons of extreme events have increased over the last 40 years," WECC said in the report.

The interconnection last year registered 40 reportable reliability events, according to the SOTI, up from 33 in 2021 and tying 2019.

WECC said such events have increased in severity over the past four years, based on NERC's severity risk index (SRI), which "measures the severity of daily conditions based on the combined impact of load loss, loss of generation and loss of transmission on the BPS," according to NERC.

Among last year's events were 10 Level 3 energy emergency alerts (EEA-3), nine of which occurred during a late summer heat wave over Aug. 30 to Sept. 10.

"The average duration of the EEA-3s in 2022 was more than 200 minutes, exceeding the av-



WECC estimates show a sharp decline in Western coal generation over the next 10 years, corresponding with steep growth in solar, wind and battery storage. | *WECC* erage duration for EEA alerts in previous years by almost double," the report noted.

Last summer's heat wave also saw the Western Interconnection set a new electricity demand record of 167,530 MW on Sept. 6, exceeding WECC's peak forecast of 164,650 MW and smashing the previous record of 162,017 MW set in August 2020. The report notes that 1,000 cities in the West saw temperature records fall during the heat wave, with afternoon highs reaching 15 to 30 degrees above historical averages.

Although not detailed in the SOTI, the West averted even higher demand — and rolling blackouts — last summer through California's emergency measures, which included heavy use of industrial demand response and last-minute calls for residents to consume less electricity during periods of peak usage. (See *California Runs on Fumes but Avoids Blackouts*.)

The report notes that 22,581 wildfires burned 3.3 million acres across the West last year, with 31 of those affecting the BPS between January and July, down from 70 such fires in 2021.

"There is no strong correlation between wildfire number or severity and risk to the BPS. This is largely because fire location is the dominant driver of risk to BPS elements," the report said.

The SOTI also highlighted the impact of drought and long-term aridification on the Western grid, with the latter having severely reduced water levels of the reservoirs behind hydroelectric dams on the Colorado River system, with Lake Powell, impounded by the 1,320-MW Glen Canyon Dam, at its lowest level since being filled in the 1960s.

While a series of atmospheric rivers this past winter have restored the reservoir levels supporting California's extensive hydroelectric system, WECC offered a cautionary note.

"Despite record precipitation over the last few months, much of the West remains in a state of drought, although conditions have improved compared to a year ago," the report said.

Dual Peaks

The SOTI addresses Western resource adequacy from the perspective of natural events and the changing resource mix. It notes that, over the last 50 years, the U.S. heat wave season has doubled from 34 to 73 days, and that grid planners are dealing with the dual challenges of higher loads in both summer and winter.

"While the Western Interconnection's peak demand occurs in the summer, many entities are winter-peaking. As temperatures and extreme weather increase, some of these entities are becoming dual-peaking. This presents resource planning challenges for entities that have historically experienced one predominant peak," the report said.

WECC pointed to a recent example: Just a year and a half after record-smashing heat in June 2021 produced record loads in the Pacific Northwest, a December 2022 cold front also caused record winter peak demand in the BC Hydro, Alberta Electric System Operator and Western Power Pool areas.

The SOTI pointed to a future Western resource mix that will be much less reliant on coal and nuclear generation by 2032 (with anticipated retirements of 13.4 GW and 1 GW, respectively), and more heavily dependent on solar (31.9 GW of new capacity), wind (9.2 GW) and natural gas (4.7 GW). WECC also projects the region will take on 18.3 GW of new battery storage over that period.

"Variability is a primary driver of resource adequacy challenges, and, based on data provided by entities for WECC's Western Assessment, variability will increase," WECC wrote. "Projections for maintaining resource adequacy depend on new resources coming online as planned, with little margin for delay. Factors such as supply chain disruption or siting delays can pose serious risks."

The report pointed out that WECC and the ERO Enterprise have "focused heavily" on the emerging risks from inverter-based resources (IBRs) such as solar and wind.

"While solar-related IBR events decreased in 2022, battery storage — also inverter-based — is increasing, expanding the potential for increased IBR-related events," the report stated.

The report also covers transmission-related developments over the past year, including final U.S. Department of the Interior approvals of the Gateway South transmission line across Wyoming, Colorado and Utah; the Ten West Link from Arizona to California; and two segments of the Gateway West project from Wyoming to Idaho.

WECC also points to other projects in the later phases of review or nearing approval, including Boardman-to-Hemingway in the Northwest, Greenlink in Nevada and SunZia in the Southwest.

"While these projects reflect progress, WECC studies show a growing risk associated with transmission availability, particularly regarding growing resource adequacy risks," the report said. ■

Calif. Bills Seek to Expedite Transmission Projects

By Hudson Sangree

SACRAMENTO, Calif. — Two bills introduced in the California legislature this year are intended to speed up approval and construction of transmission projects necessary for the state to meet its goal of supplying 100% clean energy to retail customers by 2045 while maintaining grid reliability.

One measure, *Senate Bill 420* by Sen. Josh Becker, would require the governor to identify a lead agency to "monitor clean energy and electrical transmission facility planning and deployment" needed to achieve the targets of Senate Bill 100, which established the 100% clean energy mandate in 2018, and last year's SB 1020, which set interim goals of using 90% carbon-free electricity by 2035 and 95% by 2040.

A project that the agency identifies as necessary to meet the goals would qualify for streamlined government approval and faster court review of lawsuits filed against it. It could also receive expedited review by the California Public Utilities Commission if CAISO's Board of Governors determines it is the most cost-effective solution to a "specific transmission expansion need" identified by the CPUC in its resource planning role.

Lawsuits and "duplicative review" by CAISO and the CPUC can delay transmission projects for years, Becker said in a news release.

"This isn't about cutting corners," the state senator said. "It's about streamlining the process and getting power where it needs to go in a reasonable timeframe. We talk a lot about bringing new clean energy projects online, and while that is critical, it's only one piece of the puzzle. We need to be able to get that power from the plant to the homes and businesses that need it."

The bill will be heard in the Senate Environmental Quality Committee on March 29.

CEC Certification

Another measure, *SB 619* by Sen. Steve Padilla, would expand the California Energy Commission's power to certify transmission projects entailing a capital investment of at least $250 million over five years.

Legislation signed by Gov. Gavin Newsom in June allowed the CEC to consolidate permitting for generation, storage and transmission lines that carry clean power to junction points with existing transmission. The CEC approval generally bypasses other federal, state and local permitting processes. (See *California to Pass Sweeping Energy Policy Changes*.)

CAISO's long-term transmission outlook projects a $19 billion need for in-state high-voltage lines to carry solar, offshore wind and geothermal power from generators to urban load pockets. | *CAISO*

Padilla's bill would remove the requirement that power lines connect with existing transmission and allow the CEC to approve projects "regardless of whether the electricity is carried to a point of junction with any interconnected electrical transmission system," the state Legislative Counsel's office said in its summary of the measure.

The bill is short and vague on details. It is "intended to be the starting point for a much larger and overdue conversation within the Legislature on how to meet our climate goals, deliver reliable power to homes and businesses, manage costs, and add transparency to modernizing California's electrical grid," Padilla's office said in a statement.

Padilla and Becker both cited CAISO's inaugural *20-Year Transmission Outlook*, released in February 2022, as support for their bills. To meet SB 100's goals, the ISO projected the state needs $30.5 billion in new high-voltage lines to transport renewable power from remote areas to urban load pockets. (See *CAISO Sees $30B Need for Tx Development*.)

The amount includes an estimated $12 billion for 500-kV AC and HVDC lines to carry 10 GW of out-of-state wind power from the Great Plains and Rocky Mountain states; $11 billion to upgrade CAISO's system with 230- and 500-kV lines to transport solar and geothermal power; and $8 billion for 500-kV and HVDC lines to carry 7 to 13 GW of California offshore wind to major urban areas.

"Meeting this unprecedented demand will require California to simultaneously accelerate planning, siting, permitting and construction of a modern electrical grid, while carefully managing its costs," the statement by Padilla's office said. "Current transmission projects are delayed by almost five years and have run up tens of millions of dollars in extra costs.

"Absent substantial changes to the state's current planning and permitting processes, California will not meet its visionary climate goals, and the state's fragile energy grid will experience unprecedented strain," it said. ■

CAISO/West News

FERC Approves Greenlink Nevada Incentives

By Elaine Goodman

FERC last week approved a package of transmission rate incentives for NV Energy's $2.5 billion Greenlink Nevada project (*EL22-73*).

The approved package includes the abandoned plant incentive, the regulatory asset incentive and the construction work in progress (CWIP) incentive, all of which are intended to encourage investment in transmission infrastructure.

Greenlink Nevada will consist of two cross-state transmission lines that, together with the existing One Nevada line, will form a transmission triangle around the state. Greenlink West, along the west side of the state, will be a 525-kV line from Las Vegas to Yerington. In Northern Nevada, Greenlink North will connect Ely to Yerington via a 525-kV line.

The expected in-service dates are December 2026 for Greenlink West and December 2028 for Greenlink North.

NV Energy said Greenlink will improve reliability and provide access to renewable energy zones in the state. It will also encourage regional transmission expansion and facilitate Western energy market development, the company said in its petition seeking the incentives, filed in June.

But as NV Energy's largest-ever transmission investment, "Greenlink Nevada presents significant financial and regulatory risks and challenges," the petition said.

Under the abandoned plant incentive, NV Energy can apply to recover costs if it abandons the Greenlink project because of factors outside of its control. The Public Utilities Commission of Nevada has approved the project, but it still needs additional approvals at the federal, state and local levels, the company noted.

"NV Energy has demonstrated that Greenlink Nevada faces certain regulatory, environmental and siting risks that are beyond NV Energy's control and that could lead to the project's abandonment," the commission said in granting the incentive. "Approval of the abandoned plant incentive will address those risks."

The regulatory asset incentive will allow NV Energy to recover costs that it incurs before Greenlink Nevada goes into operation. The commission also granted the utility's request to include 100% of the CWIP for the Greenlink project in its rate base.

NV Energy said the incentives will help ease strain on the company's cash flow and potentially reduce project costs. The CWIP incentive will also reduce the "rate shock" that could occur if the entire project cost was added to rates when Greenlink Nevada goes into service, the company said.

Several parties objected to NV Energy's incentive request. The Nevada Bureau of Consumer Protection said construction of Greenlink was mandated by Senate Bill 448 of the state's 2021 legislative session, and therefore incentives aren't needed to encourage NV Energy to build it.

MGM/Caesars said the incentives are duplicative and would increase costs and risks to customers.

FERC has approved NV Energy's requested incentives to construct the Greenlink Nevada transmission project. | *NV Energy*

But the commission said the package of incentives had been tailored to address NV Energy's risks and challenges for Greenlink Nevada. And SB 448 doesn't require NV Energy to build Greenlink — only to submit a plan for its development, the commission said.

Commissioner Mark Christie supported the incentive package but wrote a concurrence reiterating concerns he has expressed previously about the incentives. (See *FERC Approves Transmission Incentives for Dayton Power*.)

Under the CWIP incentive, consumers serve as a utility's de facto lender, Christie said, and with the abandoned plant incentive, consumers become the insurer of last resort.

Christie has called for the commission to revisit the incentives offered to transmission developers. ■

CAISO/West News

New Governor Seeks Shift in Nevada Energy Policy

Republican Lombardo Calls for 'Energy Independence,' Cautious Approach to Markets

By Elaine Goodman

Nevada Gov. Joe Lombardo on Monday announced an executive order outlining energy policies for his administration, including the state's "advancement of energy independence."

Nevada should develop a diverse energy supply portfolio, the order states, with a focus on affordability, reliability and sustainability. In addition to solar, wind, geothermal, hydropower, hydrogen and energy storage, Lombardo envisions a role for natural gas for electric generation and use in homes and businesses.

"The state's energy policies shall ensure all consumers and businesses continue to have diverse energy options available to them in their homes and businesses, including electric and natural gas service, energy efficiency and renewable energy resources," the *executive order* states.

Lombardo, a Republican who last year narrowly defeated incumbent Democratic Gov. Steve Sisolak, who championed clean energy policies, wants enough electric generation developed in the state "to mitigate the risk of energy markets not having sufficient electric energy supplies during peak usage periods."

At the same time, Nevada should develop transmission and energy infrastructure to make the state a regional leader in exporting its solar, wind and geothermal energy — and to import resources as needed.

Lombardo said the state should keep exploring participation in an organized Western energy market "when such a market furthers Nevada's objectives of reliability, affordability and sustainability."

Lombardo wants to promote energy innovation through partnership with universities, industries and others in the state. Job creation and economic development are goals of the policies.

Nevada Gov. Joe Lombardo | *Gov. Joe Lombardo*

The order calls for streamlining the permitting process for energy projects. State agencies should review applications concurrently rather than tackling them sequentially. The governor will advocate for a similar approach at the federal level.

The order also calls for an overhaul of the Nevada Climate Strategy, adopted in 2020, to reflect the new energy policies.

"Governor Lombardo's energy policy objectives provide a critical framework for the future of energy in Nevada," Dwayne McClinton, director of the Governor's Office of Energy, said in a statement.

Lombardo announced McClinton's appointment last month. Before starting work as the new GOE director on Feb. 20, McClinton was senior legislative policy adviser at Southwest Gas. He also has experience in the renewable energy industry and worked on Lombardo's transition team.

The Nevada Conservation League said Monday that the executive order's support for natural gas was "the wrong direction for Nevada."

Most of the state's energy now comes from gas, and high gas prices are causing Nevadan's utility bills to soar, the League said in calling for a focus on clean energy.

"Nevada has steadily made progress in reducing climate pollution and developing a local clean energy economy," Christi Cabrera-Georgeson, the League's deputy director, said in a statement. "Gov. Lombardo should lean in on these efforts and not hold Nevada back by relying on expensive out-of-state fossil fuels."

Lombardo touched on the topic of energy independence during his state-of-the-state address in January.

"California does not have enough electric generation within its own state to meet its electricity needs — and is now relying on the broader Western electric market to import energy," the governor said in his address.

"With California retiring its units and changing its transmission rules, we have no choice but to reduce our reliance on the market and seek energy independence for all Nevadans," he added.

In his new executive order, Lombardo sets as a strategic goal "having our utilities secure sufficient energy supply through dedicated in-state energy resources, including both utility-owned and third-party-owned solar, that ensure reliability for Nevadans." ■

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ERCOT News

GCPA Names Brad Jones as Power Star Honoree

By Tom Kleckner

Brad Jones listens to Oncor's Liz Jones during a 2022 conference. | *© RTO Insider LLC*

The Gulf Coast Power Association (GCPA) named former interim ERCOT CEO Brad Jones as the 2023 recipient of its Pat Wood Power Star Award in recognition of his significant contributions toward the advancement of Texas' competitive energy markets, the organization said March 21.

Jones has been credited with righting the ERCOT ship after the deadly February 2021 winter storm that nearly brought the Texas grid to its knees and killed more than 200 state residents during the ensuing dayslong power outages. Coming out of retirement, he led the grid operator's implementation of several legislative changes and leaned on a package of 60 initiatives designed to improve the Texas Interconnection's reliability and regaining the public's trust. (See *ERCOT Board Chooses Jones as Interim CEO*.)

Asked by legislative leaders to come out of retirement and lead ERCOT after the storm, Jones returned to his couch last October after 18 months. He received awards from Texas' governor, both of the state legislature's houses and the Public Utility Commission.

"All Texans owe Brad an enormous debt of gratitude for stepping up during a time of unprecedented challenge and urgency," PUC Chair Peter Lake said in a *statement*. "His steady hand and deep experience in grid operations were critical in providing the clear leadership necessary to move ERCOT forward. … Because of Brad's selfless and tireless efforts, the Texas grid is more reliable than it's ever been to the benefit of Texans today and for generations to come."

Jones is "not shy about doing tough, necessary things for improvement. … His confidence in the future of the grid and of ERCOT was contagious," said Paul Foster, chair of ERCOT's Board of Directors. "Brad left ERCOT in much better shape, both economically and in reliability."

The award is named after former FERC and PUC Chair Pat Wood III, the first honoree. Winners are selected by the GCPA's board of directors; Wood will present the award to Jones during the GCPA's annual spring conference April 18-19 in Houston.

"I have long been a Brad Jones fanboy," Wood said. "He is genuine. He is smart. He is decisive. His passion and optimism are matched only by his competence and leadership. His parents raised him right. What a gift he has been to Texas and to our industry."

Jones has more than 30 years of experience in the industry. He oversaw TXU's (now Vistra) development of the 1.8-GW Oak Grove facility and represented the company on Wall Street during a volatile time in TXU's history.

He left TXU to become ERCOT's COO, leaving the state only to serve as NYISO's CEO in 2015. He abruptly returned to Texas to retire in 2018. (See *Brad Jones out at NYISO*.) ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

Members, Staff Continue Work on PCM Bridging Option

ERCOT stakeholders last week arranged a pair of workshops as they continue to work with staff to provide bridging alternatives for a market redesign intended to preserve and attract thermal generation.

The Technical Advisory Committee scheduled workshops for March 31 and April 10 to further define market changes that could be made until a final construct is in place. ERCOT staff plan to share a strawman for the meetings and present a final recommendation during the second meeting.

Staff then plan to present their recommendation to the Board of Directors on April 18. If approved, the recommendation would then be handed over to the Public Utility Commission.

The PUC in January recommended to state lawmakers that ERCOT adopt a performance credit mechanism (PCM) as a reliability addition to the ISO's energy-only market, intended to address resource adequacy and operational flexibility challenges. The PCM would retroactively issue incentive payments to dispatchable — and primarily thermal — generation that meets performance criteria during the tightest grid periods.

Technical Advisory Committee members hold their March meeting. | *ERCOT*

The legislature has pushed back on the PCM and filed a package of bills that include building 10 GW of gas-fired generation to sit on the sidelines until load shed is imminent. (See *Texas Senate Lays out Changes to ERCOT Market*.)

At the PUC's direction, ERCOT staff has been soliciting input from stakeholders on a bridging mechanism until the final market design is developed. The options include a manually settled PCM, procuring more ancillary services, tweaking the operating reserve demand curve, and a backstop reliability service, previously offered by the PUC, to set aside capacity that is only dispatched during scarcity conditions.

By early last week, stakeholders had filed more than *two dozen comments* on bridging options, providing feedback and alternatives.

"At this point, I couldn't tell you what our recommendations are going to be," ERCOT's Kenan Ögelman, vice president of commercial operations, told TAC during its meeting March 21. "We're still kind of working through the comments and finalizing our position. You should know what we're thinking by [April 10]."

Ögelman said staff's summary of comments received so far indicate "some kind of a convergence" around changes to the operating reserve demand curve (ORDC) and an "indicative PCM value."

"But the indicative PCM value on its own would not be a bridge solution, so we're weighing that," he said.

Credit Group's Charter Approved

TAC approved a charter for its new Credit and Finance Sub Group (CFSG) that will replace

Category	Basic, manual implementation of PCM	Procure additional Ancillary Services	Enhance ORDC	Backstop Reserve Service	Contracts for Capacity *	Publish Indicative PCM Values *
Yes	2	3	11	1	1	11
Yes, Modified	4	7	5	4	3	6
No	18	13	9	17	17	7

* Refer to complementary and/or existing mechanisms that can be part of implementation or a back-up to bridging options

Summary of feedback to ERCOT on the bridge option | *ERCOT*

ERCOT News

the Credit Working Group (CWG). The new stakeholder group will be comprised of credit professionals responsible for ensuring that appropriate procedures are implemented to mitigate credit risk in ERCOT in a "fair and equitable" manner.

Austin Energy's Brenden Sager, serving as the CFSG's temporary chair, said the CWG's original charter was used as a starting point. It will review ERCOT's protocols on creditworthiness requirements or collateral calculations and provide recommendations to TAC. The group has yet to solicit members.

The CWG had reported to the board's Finance and Audit Committee since 2004, but directors last year asked that they be briefed by ERCOT staff on market credit issues. TAC agreed to take on credit oversight responsibilities and consolidated the group with its Wholesale Market Subcommittee's Market Credit Working Group. The latter group will be disbanded. (See "TAC Shares Changes with R&M," *ERCOT Board of Directors Briefs: Oct. 18, 2022*.)

Aligning ISO with Infrastructure Protection Law

TAC's combination ballot, approved by members 30-0, brings ERCOT into compliance with the state's *Lone Star Infrastructure Protection Act* (LSIPA). The 2021 law prohibits businesses and government entities from entering into agreements that would grant direct or remote access to critical infrastructure, such as the Texas grid, with foreign companies from China, Iran, North Korea and Russia.

The ballot included a nodal protocol revision request (*NPRR1155*) that would amend a market participant's eligibility criteria and make any entity that meets any of the LSIPA's prohibited citizenship, ownership or headquarters criteria ineligible to register or maintain its market participant registration.

Kenan Ögelman, ERCOT | *ERCOT*

The combo ballot also included two other NPRRs, another binding document request (OBDRR) and a Load Profiling Guide revision (LPGRR). It additionally contains a second LPGRR, a revision to the Nodal Operating Guide (NOGRR) and related single changes to the commercial operations (COPMGRR), planning (PGRR), retail market (RMGRR) and settlement metering (SMOGRR) guides, resource registration glossary (RRGRR) and verifiable cost manual (VCMRR).

The ballot includes:

- *NPRR1145*: change the 15-minute level ERCOT-wide transmission loss factors (TLFs) in the settlement process from seasonal base case TLFs to state estimator-calculated TLFs in the energy management system and clarify non-opt-in entities' deemed actual TLFs to remove behind-the-meter transmission losses.
- *NPRR1157*: require all revision requests be approved by the PUC before their implementation; add a credit review, Independent Market Monitor and ERCOT opinions, and the market impact statement to the board's TAC report; and revise possible actions on RRs from "defer" to "table," as currently captured in motions.
- *COPMGRR049*, *LPGRR072*, *NOGRR248*, *PGRR104*, *RRGRR034*, *SMOGRR026* and *VCMRR036*: require all RRs be approved by the PUC before implementation; standardize all RRs considered by the ERCOT board; add IMM and ERCOT opinions, and the market impact statement to the TAC Report; and revise possible actions on RRs from "defer" to "table," as currently captured in motions.
- *LPGRR071*: halve the required lead time from 120 to 60 days for an opt-in entity to provide ERCOT the monthly usage and demand values for its electric service identifiers (ESI IDs).
- *OBDRR044*: eliminate the weatherization-inspection fee's sunset date and change its invoicing period from a quarterly to a semi-annual basis.
- *RMGRR173*: requires all RRs be approved by the PUC before their implementation; standardize all RRs to be considered by the ERCOT board; add a credit review, IMM and ERCOT opinions, and the market impact statement to the board's TAC report; and revises possible actions on RRs from "defer" to "table," as currently captured in motions. ■

— Tom Kleckner

ERCOT News

Texas PUC Appeals Court's Decision on Uri Transactions

Commission Approves Companies' Revisions to Mitigation Plans

By Tom Kleckner

Texas regulators last week asked the state's Supreme Court to overturn a recent appeals court ruling that could force ERCOT to unwind market transactions during the deadly February 2021 winter storm.

Attorneys for the Public Utility Commission said in a filing Thursday that the appeals court's ruling should be overturned because the orders it issued expired years ago and therefore cannot be voided. They defended the commission's actions during the storm, saying it made "split-second decisions" necessary to help correct a market failure (*23-0231*).

The PUC urged the Supreme Court to review the decision, reverse the judgement, and either dismiss the case or rule in the commission's favor.

The 3rd Court of Appeals on March 17 reversed two PUC orders to keep the market's wholesale prices at the $9,000/MWh cap during the storm. The court found the commission's actions "entirely" eliminated competition and were contrary to state law. It remanded the case for "further proceedings consistent" with its ruling. (See *Texas Court Reverses PUC's Uri Market Orders*.)

The PUC said the high court should grant its petition because the orders in question expired shortly after the storm, rendering them moot.

"They no longer exist, so the Court of Appeals could neither affirm nor reverse them," its attorneys argued.

The commission said the appeals court created "harmful precedent" by allowing a statute's general policy statements to "trump both specific grants of authority and the statute's overall policy objective." The court focused solely on market competition, it said, ignoring the PUC's responsibility to balance the law's policy objectives.

It said the court's reasoning calls into question any commission rule that "arguably limits competition" and that its "invented" constraints could hamstring future efforts by the PUC and ERCOT to "ensure 'the reliability of the regional electrical network.'"

The PUC's attorneys also argued that the appeals court's decision has "surprised the electricity world" and introduced "mass uncertainty" into Texas's electricity markets.

"The markets are already reacting to that uncertainty in ways that are hard to predict," they wrote.

3 Mitigation Plans Amended

During the PUC's open meeting last week, it also approved amended voluntary mitigation plans (VMP) for Luminant, NRG Energy and Calpine that add "clear" guidelines for their non-spin reserve service (NSRS) offering practices in ERCOT's day-ahead ancillary services market (*54739*, *54740* and *54741*).

Staff earlier this month determined that language in the mitigation plans provided the generators with an "absolute defense" against market abuse allegations related to the service's submitted offers at prices up to the high systemwide offer cap (HCAP). They estimated non-spin capacity awarded to large suppliers for noncompetitive offers submitted between August 2021 and July 2022 to be between $285 million to $380 million.

The revisions eliminate language that allows offers and/or bids for day-ahead market energy and ancillary services at prices up to and including the HCAP.

Non-spin ancillary service market outcomes are affected by offers from all suppliers, and Luminant, NRG and Calpine are the largest suppliers. ERCOT's conservative operations posture, instituted in the latter part of 2021, expanded the service's procurement from an hourly range of 1,175 MW-1,838 MW to 3,654 MW-4,303 MW. That affected the amount of excess supply and increased the likelihood that the grid operator must rely on certain suppliers to meet procurement requirements.

Staff said that when a supplier is frequently pivotal to non-spin's procurement, it does not forego profit if it submits offers higher than a competitive level. Instead, they said, the supplier would be incented to increase its offers to obtain excess rent and would effectively be able to control the price at which ERCOT must procure ancillary services.

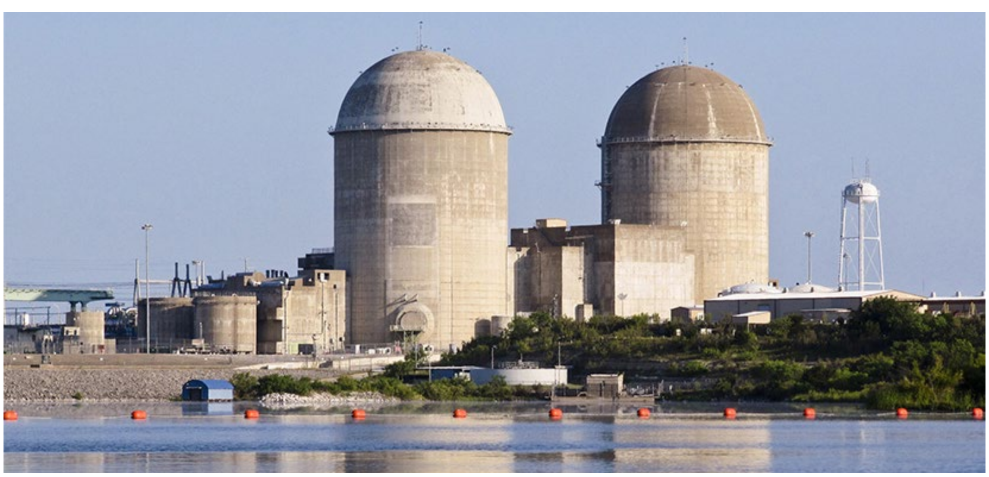
Independent Market Monitor Director Carrie Bivens, who signed off on all three mitigation plans, said they were not effectively mitigating anticompetitive conduct in the non-spin market "given that there is currently no planned end date to ERCOT's increased non-spin procurement."

She said the amended mitigation plans will continue to provide the generators with "reasonable safeguards against the potential exercise of market power in the ERCOT markets that may constitute an abuse of market power."

One of nine bills offered by the Texas Senate earlier this month addresses VMPs. *SB2011* would require plans be updated at least once every two years and raises violations from $25,000/day per violation to up to $1 million/day per violation. (See *Texas Senate Lays out Changes to ERCOT Market*.)

Luminant's mitigation plan dates back to 2019, NRG's to 2012 (it was first amended in 2014), and Calpine's to 2013.

The PUC did not assess any financial penalties. ■



Luminant's Comanche Peak Nuclear Power Plant | *Vistra*

ISO-NE News

FCA 17 Shows Clean Energy Boost, Endgame for Coal in New England

ISO-NE last week touted its role in New England's clean energy transition as it announced the finalized results of Forward Capacity Auction 17, for the 2026-2027 procurement period.

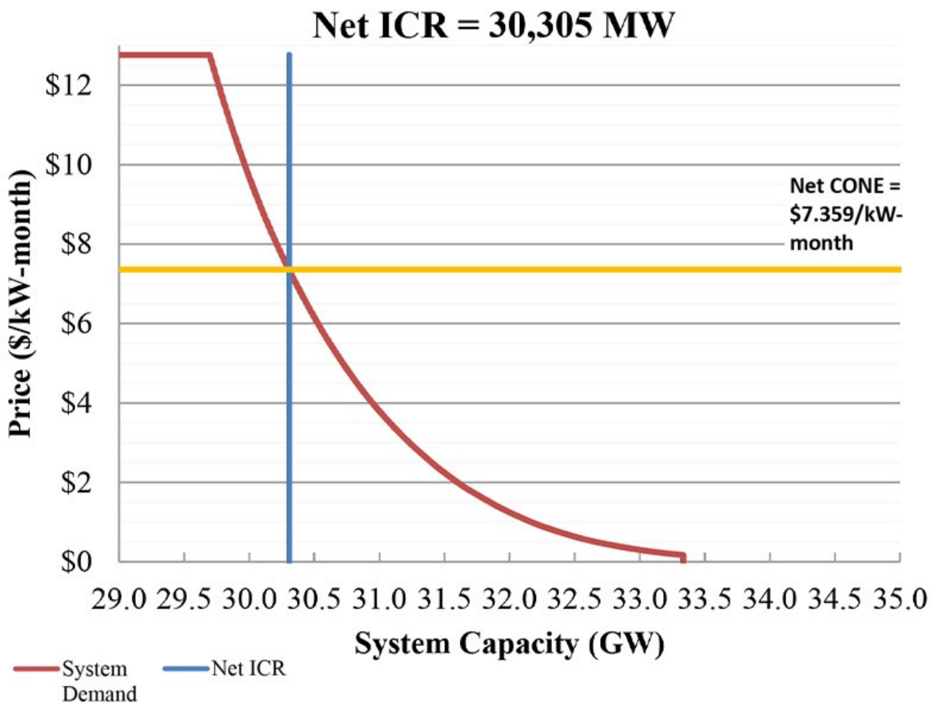
Non-emitting generators secured nearly a quarter of the auction's total obligations, the RTO said March 21.

"The 7,620 MW of obligations secured by these resources represents an 11% increase over the 6,844 MW of obligations secured by non-carbon-emitting resources in the 12th Forward Capacity Auction, held in 2018," the grid operator said in a press release.

Solar and wind generation accounted for 3.5% of all obligations in FCA 17, and battery storage accounted for another 3.5%.

In that vein, the auction may also signal that an end to the use of coal for generation in New England is near: The region's last remaining coal-fired plant, Merrimack Station in Bow, N.H., submitted a dynamic delist bid and did not win a capacity supply obligation.

In its *detailed explanation* of the auction, the grid operator said that its reviews of delist bids, including three permanent ones totaling 12.5 MW and two retirements worth 7.8 MW, did "not show the need to retain for reliability any resources"; all of the bids were therefore accepted.



ISO-NE's systemwide capacity demand curve for FCA 17 | *ISO-NE*

Among the significant delist bids were two oil units at the Middletown plant in Connecticut and the Millennium gas plant in Massachusetts.

ISO-NE also confirmed that the clearing prices it listed in its initial announcement were accurate: $2.59/kW-month in all zones and import interfaces except for the New Brunswick interface, which cleared at $2.551. ■

— *Sam Mintz*

ISO-NE News

Overheard at NE Electricity Restructuring Roundtable: March 2023

BOSTON — A panel of experts made the argument for smarter rate design on Friday at Raab Associates' New England Electricity Restructuring Roundtable last week.

Updating rates to send better price signals is the key to unlocking the power of demand, the panelists said.

It's a process that's "more art than science, or more behavioral than economics," said Janet Gail Besser, the panel's moderator.

The speakers focused on Massachusetts, where the roundtables are held.

"With last fall's Department of Public Utilities order requiring the utilities in Massachusetts to develop advanced metering infrastructure implementation plans, it appears there will be new opportunities for innovative rate design that can encourage electrification and reduce carbon emissions," said Besser, a former chair of the DPU.

Electricity rates have been changing in structure for decades, but there's one consideration that's upped the ante in recent years, said Sue Tierney, a senior adviser at Analysis Group.

"What's different now is the urgency of evolving the electric system as part of the path to decarbonizing the economy," Tierney said.

An effective change to rate design to help start boosting demand is time-of-use rates, the panel agreed.

"Time-varying rates is an essential tool," Tierney said. "Having it as a default option provides two opportunities: for the customer to take charge and figure out what they want to do in terms of their own energy management; and it sets up the context for … retailers and aggregators to use those time-varying rates."

In the last few years, five states have started implementing opt-out time-of-use rates. Massachusetts is not one of them, and again the panel picked on the Bay State.

"Our customers in Massachusetts, we don't know how much energy they're using until we get the bill from utilities a month later. And we have no idea at any point in time when our customers are using energy," said Travis Kavulla, vice president for regulatory affairs at NRG Energy. "So there's no incentive or practical ability at all … for us to make investments in demand response."

Melissa Whited, a senior principal at Synapse Energy Economics, offered another way to tweak rates to incentivize electrification of vehicles or home heating: playing around with how customers are charged.

For example, she said, states have traditionally tried to keep fixed charges low, and let volumetric rates stay higher, to incentivize customers to conserve energy.

"But with electrification, high volumetric rates are a barrier to adopting new technologies," Whited said. So, California has experimented with high fixed charges with low volumetric rates limited to customers who are using certain demand-side technology.

There's also an argument to be made for a broader overhaul, said Harvey Michaels, a lecturer at the Massachusetts Institute of Technology who has studied heat pump adoption.

"We have to realize as part of what we're doing now that charging electric bills for the energy efficiency programs and other things we do, particularly when they're competing with a gas-fired alternative, is shooting us in the foot," Michaels said. "We have to figure out how to pay for these things with something other than electricity." ■

— Sam Mintz

MISO News

FERC Order May Delay MISO's 1st Seasonal Capacity Auction

By Amanda Durish Cook

NEW ORLEANS — MISO may have to delay its first seasonal capacity auction after FERC issued a show-cause order March 17 for the RTO's capacity ratio that it must publish ahead of the auction.

FERC ordered MISO to either update an unforced capacity to intermediate seasonal accredited capacity ratio that it uses to gauge anticipated supply or explain why it shouldn't have to. (See *MISO Issued Show-cause on Seasonal Capacity Auction Values*.)

Executives said last week the order will hinder MISO's ability to conduct the seasonal auction on time.

Staff reported that a software error counted previously excused generation outages against capacity accreditation, resulting in smaller capacity values than expected. While they corrected individual ratios for multiple units, they did not update a summary systemwide ratio. The RTO said it didn't have time to rework the systemwide data point before it conducts the 2023/24 planning resource auction.

"It will likely mean an ultimate delay in our auction," Zak Joundi, director of resource adequacy coordination, told the Board of Directors' Markets Committee on March 21.

Joundi said MISO expects to publish auction results in mid-May, about a month behind schedule.

The four seasonal auctions that were to be conducted concurrently in early April are the grid operator's first stab at using a seasonal capacity framework.

Joundi said FERC's order was "hot off the presses" and that staff was still reviewing the commission's directive. He acknowledged that members and staff might be disappointed by the delay, but the ratio must be recalculated.

"I understand that there are a lot of folks in the room that have done a lot of work," he said.

"We're going to comply with what FERC tells us and get this auction run as quickly as possible," MISO Independent Market Monitor David Patton said.

Patton had alerted the RTO late last year that it was artificially inflating seasonal capacity requirements because it assumed generators on planned outages were offering capacity. (See *IMM: Faulty Assumption in MISO's Seasonal Auction Design*.)

"A little bump in the road here, but you're a leader in this area, and I commend you," MISO Director Tripp Doggett said, referencing the seasonal auction.

WEC Energy Group's Chris Plante said the potential delay and revised ratio shows that the stakeholder community may have been justified in urging MISO to delay the auctions for a year and to use its normal annual method for the 2023/24 planning year.

"I think there's a lesson to be learned here, and that's stakeholders are experts in this process alongside MISO," he said.

Staff used mounting reliability risks outside the summer peak as evidence that they needed to get a jump on dividing capacity contributions and requirements by season. ■

MISO's Markets Committee of the Board of Directors on March 21 | *© RTO Insider LLC*

MISO News

FERC Approves SSR Agreement for Wisconsin Coal Plant

By Amanda Durish Cook

Manitowoc Public Utilities' Lakefront power plant | *Manitowoc Public Utilities*

FERC last week approved a MISO system support resource (SSR) agreement that will keep a Wisconsin coal plant operating for reliability purposes.

Under the agreement, Manitowoc Public Utility will continue to operate its Lakefront Unit 9 coal-fired unit, effective Feb. 1 (*ER23-914*).

In a separate order, the commission questioned Manitowoc's request for $1.03 million in monthly compensation for the plant, saying it might be overcharging customers for the one-year SSR. FERC established hearing and settlement judge procedures to settle the matter (*ER23-977*).

MISO told the commission that it would face unresolved thermal overloading and steady-state voltage issues on 12 constraints if Lakefront 9 was permitted to suspend operations as scheduled. The 63-MW unit began operations in 2006 and serves load in Manitowoc, Wisc. MISO said there weren't any nearby resources available to redispatch, viable transmission reconfiguration options, or enough demand-side management to avoid an SSR. (See *MISO Proposing 2nd SSR Agreement for Retiring Coal Unit*.)

FERC found that the RTO had no "feasible alternatives that could resolve the identified reliability problems … to avoid the need for the Lakefront Unit 9 SSR agreement." The grid operator uses the agreements to keep generators online past their retirement dates as a last-resort measure for system reliability.

Manitowoc intended to suspend the unit and convert it for renewable fuel sources. It said it plans to bring the unit back to full commercial operation by the end of January 2026 "when the alternative fuel source becomes available in sufficient quantity."

The municipal utility said it needs more than $1 million to cover operations and maintenance labor expenses, administrative expenses, non-labor maintenance expenses, site security, insurance, carrying charges and various fees and taxes.

Wisconsin Public Service and WPPI Energy protested Manitowoc's proposed amount, arguing the utility showed no basis for its cost projections and estimates.

WPPI said Manitowoc used "unsubstantiated forecast inputs" in its cost-of-service model, "impeding the commission and consumers from undertaking a proper evaluation of the proposed charges."

FERC agreed. It said its preliminary analysis indicated that Manitowoc's requested amount might be unreasonable.

The SSR designation is MISO's second within a year. In October, it received FERC permission to instate an SSR agreement for Ameren Missouri's 1.2-GW Rush Island coal plant. The commission also cast doubt on the reasonableness of the monthly compensation in that proceeding. (See *FERC: Rush Island Plant's Extension Essential to MISO Reliability*.) ■

Midwest news from our other channels

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Mich. PSC OKs Higher Outage Credits, Stricter Requirements for Restoring Power ERO Insider

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MISO News

Danly Addresses Capacity Auction Snafu at MISO Board Meeting

By Amanda Durish Cook

NEW ORLEANS — FERC Commissioner James Danly paid an unannounced visit to MISO's Board of Directors meeting Thursday following a snag in the RTO's new capacity accreditation process that will delay next month's planned capacity auction.

Danly urged MISO's leadership to "recommit" to market fundamentals. He said the grid operator must ensure that its prices incent resource adequacy and that it follows "steady, deliberate" changes to its tariff.

MISO will experience high capacity prices when scarcity conditions are present, Danly said.

"As the old saying goes, the solution to high prices is high prices," he said.

FERC issued a show-cause order to the RTO on March 17, directing it to recalculate a systemwide capacity ratio used to validate accreditation values for planning resources or explain why it shouldn't have to (EL23-46).

MISO said it will recalculate seasonal accredited capacity ratios but doing so will likely delay its first four-season auction. Its original unforced capacity to seasonal accredited capacity ratio erroneously counted some previously excused planned outages against some generators' availability. (See *FERC Order May Delay MISO's 1st Seasonal Capacity Auction*.)

Danly discouraged MISO from "chopping and changing" its market design, saying reactionary alterations make it "rationally impossible" for market participants to respond to and prepare for structural changes. He said his advice extended to other grid operators.

MISO told *RTO Insider* after the meeting that Danly's appearance was coordinated weeks prior between it and FERC, though it did not tell stakeholders he was coming. The RTO said that as a rule, it does not place addresses from FERC commissioners on its meeting agendas. It also said that when it scheduled Danly's visit, it had nothing to do with its seasonal capacity auction. However, Danly's remarks focused exclusively on the capacity market.

MISO CEO John Bear said staff will ensure stakeholders have enough time to understand the recalculated ratio and how it affects thermal resources' accreditation before running the auction.

The recalculated ratios are expected to result in "reduced accreditation values for individual market participants and on an aggregate basis," MISO says.

Entergy and other market participants have warned that smaller capacity values for their units may cause shortfalls in some MISO zones for certain seasons. (See *FERC Denies Exemption Requests from MISO Accreditation Rule*.)

FERC Commissioner James Danly delivers comments to the MISO Board of Directors on March 23. | *© RTO Insider LLC*

During an Advisory Committee meeting Wednesday, Jim Dauphinais, an energy consultant representing multiple MISO end-use customers, said it's important that the grid operator back up and make sure it's using correct values in the auction. He said that while it was "unfortunate" how it played out, FERC's order and subsequent delay illustrates how untested market changes can cause disruptions when systems and people aren't prepared.

"Quite frankly, we don't know if our seasonal construct is working," Dauphinais said. ■

MISO News

PSC Chair Says Michigan Grid 'Nowhere it Needs to Be'

By John Lindstrom

LANSING, Mich. — Michigan Public Service Commission Chair Dan Scripps told members of the state Senate last week that the state's electric grid is "nowhere it needs to be," as evidenced by the large number and long duration of utility outages that 1 million residents suffered through in February and early March.

Speaking at budget hearing for the PSC before a Senate Appropriations subcommittee March 21, Scripps said the commission would approve regulatory changes to improve utilities' performance. (See *Consumers, DTE Energy on the Hot Seat over Michigan Outages*.)

The commission took final action Friday to change how utilities pay credits to customers who lose power for extended periods of time. The proposed rules have gotten the go-ahead from the bipartisan Joint Committee on Administrative Rules, Scripps told the subcommittee.

Scripps spoke to the subcommittee after the PSC held public hearings about the outages in Jackson, home of CMS Energy and Dearborn, a suburb of Detroit, home of DTE Energy.

Commissioners heard a wide variety of complaints from customers about the outages. Scripps told the subcommittee the PSC has had a major focus on outages for the last several years. The state suffers from too many outages and outages that last for too long, he said.

"We have a significant amount of work to do," Scripps said.

An audit to investigate the state of Michigan's utilities and how to reduce the number and duration of outages should improve the situation, he said. The PSC issued the bid request this month and hoped to have a decision on a company to conduct the audit by the end of April.

The PSC ordered the audit in October, prompting one senator to ask why it took so long to issue the bid request. Scripps said it was the first time the PSC had sought an audit, and the commission needed time to develop the questions and areas it wanted to focus on. Even so, Scripps said, he was surprised at how long it took. It was "eye opening," he said.

Sen. Sylvia Santana (D), who represents Dearborn, said she hoped the PSC would act on the audit's recommendations — which are not expected before April 2024 — before considering any rate hike requests by the utilities.

The subcommittee chair, Sen. Mary Cavanagh (D), asked if the PSC would consider requiring more lines to be put underground to help reduce outages. Utility executives have also said they will look at moving some lines underground.

Scripps said there was no single fix for reducing outages, but that moving lines underground — especially in some areas where it may be cheaper than trying to keep vegetative growth controlled — could be an option. ■

Michigan Public Service Commission Chairman Dan Scripps | *Michigan Public Service Commission*

MISO South Advocates Ask for Broader Tx Planning

By Amanda Durish Cook

NEW ORLEANS — Clean energy advocates and a transmission developer asked MISO's Board of Directors last week for stronger transmission plans and a facility blueprint for MISO South.

Southern Renewable Energy Association's Andy Kowalczyk said he shared multiple stakeholders' concerns that the grid operator has waited too long to address long-term transmission needs in the South.

Noting Entergy joined MISO in 2013, he said, "I know that in transmission planning terms that seems like yesterday, but MISO South has yet to be fully connected with our neighbors to the north. Only a narrow path between the north and south exists, and there's been no truly regional planning in the subregion compared to the north in the past decade."

MISO plans to bring a second long-range transmission plan (LRTP) portfolio forward for the board's consideration sometime next year. The recommendation will again be focused on MISO Midwest and could hit $30 billion, staff have said. (See *MISO Says 2nd LRTP Portfolio Still in Flux*.)

During the board's System Planning Committee meeting March 21, Aubrey Johnson, vice president of system planning, said MISO's second, middle-of-the-road, 20-year planning future indicates renewable energy and carbon reduction will increase by 2030. Past Future 2 iterations didn't anticipate the transformation until 2040; it will influence the second leg of MISO's LRTP.

Clean Grid Alliance's Beth Soholt said MISO's futures refresh is "further evidence" that the transition is happening at a much faster pace than anticipated.

"A trend we've always had with the utilities and at MISO is that transmission capacity is full before it is constructed and goes into service," she said. "Given the very large interconnection queue in MISO, which is responding to demand for new resources, we are seeing this same trend again."

Soholt said the Midwest's first planned LRTP lines are quickly being spoken for. She said the future's update almost triples the footprint's renewable energy resources that will require sizeable transmission additions. Soholt urged the board to ensure staff is planning to build the bulk transmission system "at the appropriate bigness."

Kowalczyk said despite MISO's "major successes" with its Midwest LRTP plan, "the planning paradigm needs to change for the South." He said it "should be unacceptable" that the grid operator will wait four years before it considers Southern needs.

The New Orleans resident said he was "genuinely worried" that the southern grid will falter during future emergencies. Kowalczyk said solar projects in Arkansas and Louisiana need new transmission capacity to come online.

"We need MISO to commit to planning for the future MISO South, for the good of the entire footprint," Kowalczyk said.

NextEra Energy's Matt Pawlowski urged MISO to be more aggressive on transmission planning. He said early green hydrogen projects, other new load and several generation developers want to join the system. Pawlowski said the region risks losing out on renewable energy and economic development if it doesn't get more planning intensive.

"None of this happens without transmission. The more aggressive we are, the better off we are to accommodate these loads," he said. "The message to you on transmission is: We need to be aggressive on scenarios; we need transmission now. We're already behind."

Pawlowski said he doubted staff's projections to energize the first batch of LRTP projects by 2028 or 2030. He said in his experience, construction and permitting should take 10 to 15 years, not MISO's more optimistic forecast.

"Emerging industries like green hydrogen and offshore wind are getting a lot of attention from the business community and there are serious efforts to take advantage of federal incentives, but without being able to reliably deliver gigawatts of clean energy, they will not flourish," Kowalczyk warned.

MISO's "other" project category in its annual Transmission Expansion Plans drew interest at MISO Board Week. They include transmission owners' projects needed for load growth and to address existing facilities' ages and conditions. Stakeholders have said at times that the category appears to be a catch-all and is difficult to understand.

"How much work is MISO really doing to understand this category? I'd like to understand MISO's due diligence on this," Director Nancy Lange said.

Laura Rauch, senior director of transmission planning, said "other" projects often are largely driven by localized reliability needs, as opposed to NERC and regionally defined standards that drive baseline reliability projects. ■

The System Planning Committee of the MISO Board of Directors meets on March 21. | *© RTO Insider LLC*

MISO Winter Recap Centers on December Emergency

By Amanda Durish Cook

NEW ORLEANS — MISO's annual winter look-back focused almost exclusively on operations during the widespread Dec. 23 deep freeze, with staff vowing to work on emergency coordination with their neighbors and digging into why the RTO was asked to shrink flows on its Midwest-South transmission transfer.

"So, a difficult quarter," MISO Independent Market Monitor David Patton said as he began his postmortem before the Board of Directors' Markets Committee March 21.

Patton said had it not been for the winter storm, real-time energy prices would have been down 11% year-over-year. Instead, they were up by 15% at $47.60/MWh.

Jessica Lucas, executive director of system operations, joked that Winter Storm Elliott was "the Christmas gift that no one wanted." She said if the storm had lasted two full days, its "impacts could have been much more severe."

Lucas said MISO consistently exported power to southern neighbors, including emergency energy to Tennessee Valley Authority, and complied with requests to reduce its Midwest-South transfers by 1,500 MW. The grid operator typically flows 3,000 MW south and 2,500 MW midwest over the connection.

MISO went into Dec. 23 with *19 GW* of unplanned outages from the day before. The grid operator was forced to call a maximum generation event, calling up emergency resources as it also exported energy to neighbors. (See *MISO Defends Energy Exports During December Storm*; *MISO Data Show Steep Gas-fired Outages During Winter Storm*.)

Lucas said fuel issues played a significant role in gas-fired generation outages, with multiple units unable to start. She also said the gas market was on holiday, complicating matters and preventing generation owners from buying additional fuel. She said "strong wind performance" kept operations afloat.

Entergy Arkansas' Arkansas Nuclear One plant pictured within the span of a few days in January 2023 | *Entergy Arkansas*

"MISO maintained reliability across the footprint with no interruptions," she said.

When asked how operations performed during the storm, Renuka Chatterjee, vice president of operations, said the phrase that comes to mind is "dodging a bullet."

"The only difference between this and Winter Storm Uri was the wind output," she said.

Patton said it's "boggling" that gas markets are allowed to close for weekends and holidays.

"The fact that gas doesn't trade on a weekend is hard to understand … We can't shut our markets down on a weekend," he said.

Patton said MISO lost two 1 GW generators on either side of the regional connection almost simultaneously as the RTO's neighbors asked it to dial down the transfer constraint's flows.

Lingering Questions on Transfer Reduction

Patton said MISO needs to understand why its neighbors needed the transfer's cutback.

"We've been asking our neighbors about the situation to cut, and we haven't heard anything," Patton said. He added, "This has nothing to do with MISO's shortcomings."

He said with more information from its neighbors, the RTO might be able to manually redispatch generation before taking more dramatic steps.

Patton said the many gas generation outages from units without backup fuel shows the importance of MISO accrediting capacity on the margins. He said a marginal aspect in capacity accreditation isn't meant to single out only renewable generation. (See *MISO Accreditation Impasse Persists at Workshop*.)

JOAs with Neighboring Systems?

Patton also said the "massive exports or

MISO News

wheels through MISO" during the storm means the grid operator should more clearly define how it expects its control room staff to react during widespread emergencies in the Eastern Interconnection.

He said the RTO and its neighbors need joint operating agreements that "specify what you can expect from us and specify what we can expect from them."

"Typically, you should never shed load to protect non-firm exports," Patton told the board.

Less than a month earlier, Patton advocated that the system operator sign JOAs with its neighbors. He said procedures should cover a "slew of deliveries" that operators can take in risky situations.

"I'm shocked that NERC doesn't require RTOs to have joint operating agreements across all the major seams," he said during the Gulf Coast Power Association's MISO/SPP conference in early March.

Patton said MISO customers are going to see "tens of millions" due from the storm, partly because of its actions to help its neighbors.

"When you don't have joint operating agreements … it's really hard to see good interregional collaboration on a forward, or a planning basis," he said.

Jennifer Curran, senior vice president of planning and operations, agreed that MISO and neighboring systems should determine coordination frameworks.

Director Robert Lurie said it was "interesting" that the RTO was able to keep exporting power while in emergency procedures. He said the storm shows the importance of interregional flows and managing constraints.

"First, I want to say that all things considered, you did a remarkable job," Director Phyllis Currie told executives.

She asked whether staff could collaborate with its neighbors before facing emergency procedures. Chatterjee said they held a conference call with PJM soon after the storm and that it is interested in creating a specialty market product with MISO for use during emergencies.

Southern Renewable Energy Association' executive director, Simon Mahan, said Winter Storm Elliott showed that fossil fuel generation "is just as susceptible to the weather as wind energy or solar energy."

Mahan said MISO's exports during the storm indicates that the grid operator should redouble its efforts to plan interregional transmission.

Under "blue sky" conditions, he said, sturdier interregional links are a more efficient way to operate the Eastern Interconnection.

"Those same connections are literally a lifeline in extreme weather events. MISO needs to work with its neighbors to expand its regional transmission planning efforts outside of MISO and better connect MISO North with MISO South," Mahan argued. "It can probably be said, and without exaggeration, that MISO's actions saved lives during Winter Storm Elliott. But it still wasn't enough to completely prevent the blackouts [in Duke Carolinas' territory and TVA]."

Mahan said grid planners can underestimate the value of interregional transmission "because we don't have a perfect way to calculate the true value of a warm meal or a hot shower." ■

NYISO News

No Emergencies for NYISO Despite Storm, Cold

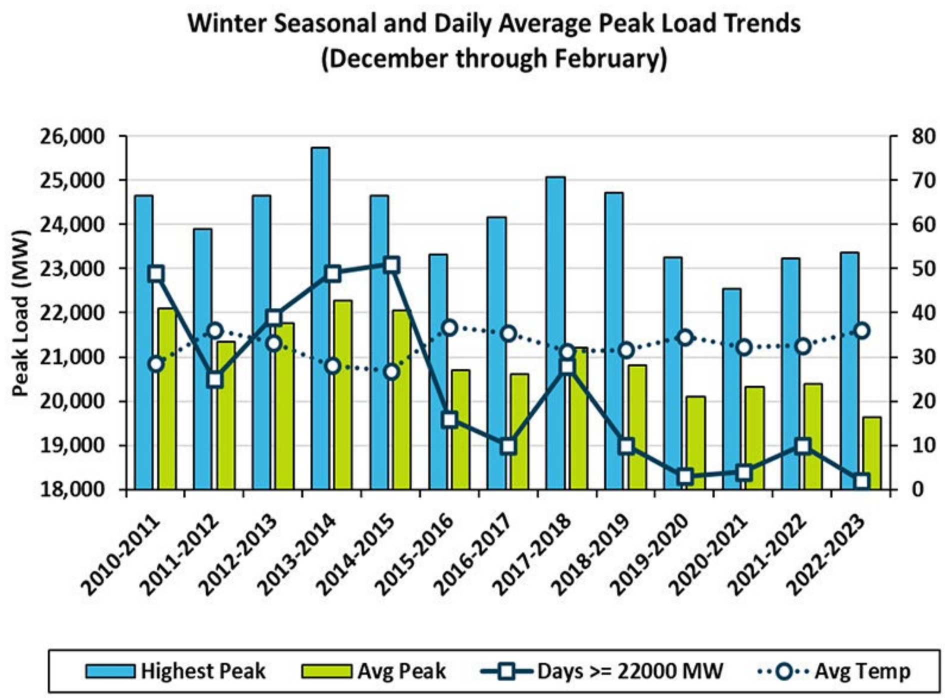
By John Norris

December's winter storm and early February's cold snap challenged the New York grid, causing outages and operational flow orders, but they did not cause any emergencies, NYISO told the Operating Committee this month.

Temperatures this winter were higher than normal, with the average temperature in Central Park during January being 43.5 degrees Fahrenheit, nearly 10 degrees over the 1991-2020 average. This January ranked highest in terms of average hourly temperature (37.5 F) among all years since 2011, and there were only 11 days in the month with a peak load of more than 20,000 MW, with the average since 2011 being 26.

But the two extreme weather events caused temperatures to drop rapidly. Aaron Markham, NYISO vice president of operations, noted that on Dec. 24, it was 50 F at noon in both Albany and New York City; by 8 p.m. that night, it was 15 F. Both natural gas pipelines and gas-fired generators experienced forced outages during the December storm because of frozen production wells and compressor stations.

Still, peak load only reached 22,004 MW during the storm, partly because, Markham said, it coincided with the Christmas holidays, which happened to be over the weekend. Conditions were tighter during the February cold snap, with the peak load of the season occurring on Feb. 3 at 23,369 MW, just shy of NYISO's forecast of 23,893 MW. Temperatures dropped to as low as 2.3 F on Feb. 4, averaging 16.5 and 9.5 on Feb. 3 and 4, respectively.



| NYISO

However, Markham noted that there was little precipitation during the February event, and gas supply interruptions and plant outages were less than during the storm.

Markham also highlighted that significant amounts of stored fuel were burned during the two events, concerning the ISO about replenishments for next winter. NYISO also heavily relied on oil-fired generation during the peak periods, with oil supplying 23% of power during the peak hour; gas supplied 24%. Gas prices in Iroquois Zone 2 reached $135.50/MMBtu on Feb. 5.

Nevertheless, NYISO was able to operate through the two events without calling on demand response resources or issuing any emergency actions, such as voltage reductions or public appeals for conservation. ■

PJM News

Monitor Seeks Access to PJM Liaison Committee Meetings

By Devin Leith-Yessian

The PJM Independent Market Monitor on Monday filed a complaint to FERC alleging that the RTO is in violation of its tariff by not permitting the Monitor to attend Liaison Committee meetings (*EL23-50*).

"It is inconsistent with the independence of PJM, the PJM board and the independence of the Market Monitor to exclude the Market Monitor from any stakeholder process," the IMM argued. "PJM should be directed to permit the Market Monitor to register for and participate in meetings of the Liaison Committee."

The next LC meeting is *scheduled* for April 3.

The Monitor was able to attend the committee's meetings until 2018, when the Members Committee voted to enforce the LC's charter and restrict participation to RTO members and the Board of Managers, also preventing state regulators and FERC staff from attending. The Monitor quoted the PJM tariff in arguing that it is allowed to participate in stakeholder meetings when it determines its participation to be "appropriate or necessary to perform its functions," and that charter provisions in violation of the tariff cannot be enforced. (See "Liaison Committee Meeting to be Closed to Nonmembers," *PJM MRC/MC Briefs: Sept. 27, 2018*.)


Monitoring Analytics President Joe Bowring | © *RTO Insider LLC*

The West Virginia Public Service Commission has also filed a complaint against PJM over its exclusion from LC meetings, arguing that the tariff requires that *ex officio*, nonvoting members be allowed to observe and that preventing them from doing so is also a violation of nondiscrimination provisions in the Federal Power Act Sections 205 and 206 (EL23-45). (See *W. Va. PSC Files Complaint over PJM Meeting Policy*.)

After also being excluded from LC meetings in 2018 alongside the Monitor, West Virginia PSC staff attended two MC meetings in September and November 2021 to push for stakeholders to vote on a rule change to permit their attendance. A motion was made during the Nov. 17 meeting to open the LC, but stakeholders narrowly voted to indefinitely table discussion. ■

PJM News

FirstEnergy Hires Tierney as New Chief Executive

By John Funk

FirstEnergy's board of directors on Monday *announced* the appointment of a new CEO who is currently a senior executive at the investment company Blackstone.

Brian Tierney, 55, will join the Ohio-based company as president and CEO on June 1, succeeding board Chair John Somerhalder II, who has held the top management spot since September in addition to his board responsibilities.

Tierney has spent 28 years in the utility industry, 23 of them with American Electric Power, serving as executive vice president and CFO from 2009 to 2020. He was executive vice president of strategy in 2021 when he joined Blackstone as senior managing director and global head of infrastructure operations.

"Brian Tierney is a proven leader with deep experience in the energy industry, a unique blend of operational, financial and strategic skills, and a sterling record of driving growth and transformation within our sector," Somerhalder said in a statement. "Over the last several years, we have taken decisive actions to reposition FirstEnergy for the future. The board's search committee set out to identify a leader who could continue the important work underway to drive the company forward while bringing critical outside expertise and perspectives.

"We could not have selected a better suited candidate than Brian. We look forward to working closely with him to build on FirstEnergy's momentum and enhance value for our shareholders and other stakeholders."

New FirstEnergy CEO Brian X. Tierney | *FirstEnergy*

Tierney is the company's third CEO since the company fired Charles Jones in October 2020 after an internal investigation determined that he and two other top executives had violated the company's code of conduct in a bribery scheme involving former Ohio House Speaker Larry Householder and the passage of legislation bailing out the company's nuclear power plants in the state. (See *FirstEnergy Fires Jones over Bribe Probe*.)

The company appointed CFO Steven Strah as CEO the same day it fired Jones. Strah abruptly retired in September 2022 following the board's announcement that it had completed a review of its top management team in accordance with the settlement of shareholder federal lawsuits. (See *FirstEnergy CEO Abruptly Retires, Without Severance*.)

Tierney's appointment comes a little over two weeks after a federal jury in Cincinnati found Householder and a former Ohio Republican Party chairman guilty of racketeering conspiracy. (See *Householder Convicted in FirstEnergy Bribery Case*.) Both are planning to appeal as the Justice Department continues its investigation. ■

Mid-Atlantic news from our other channels

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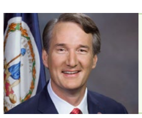

Youngkin Signs Energy Bills to Aimed at Growing Southwest Va. Industry — NetZero Insider

Ky. Law Raises Hurdle for Fossil Fuel Generation Retirements — NetZero Insider

Regulators Boost Incentive for NJ's Largest Floating Solar Project — NetZero Insider

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PJM News

FERC Approves PJM Proposal to Reduce Congestion Penalty During Grid Upgrades

By Devin Leith-Yessian

| © RTO Insider LLC

FERC last week approved a PJM proposal to allow it to reduce the transmission constraint penalty factor (TCPF) under a set of circumstances that the RTO argued becomes punitive to load without providing any benefit (*ER23-918*).

The tariff and Operating Agreement revisions allow the factor to be reduced when localized transmission congestion is caused by the construction of upgrades — and the necessary deactivation of certain lines — that were either part of PJM's Regional Transmission Expansion Plan (RTEP) process or to interconnect a generator. The TCPF would be reduced from its default of $2,000/MWh to a level that reflects the offers from resources available to address the congestion.

Given that the TCPF's purpose is to incentivize generation or transmission solutions to congestion, PJM argued that when congestion is caused by upgrades that will resolve the issue upon their completion, it is unrealistic to expect a short-term investment to address the situation, and the penalty factors can become counterproductive. PJM stated that the average line outage caused by upgrades lasts an average of 211 days.

"Where a transmission facility is taken out of service altogether due to an RTEP or interconnection upgrade, however, long-term price signals reflecting the default ($2,000/MWh) transmission constraint penalty factor cap do not serve the intended purpose given that the transmission upgrade currently under construction will mitigate these issues," PJM Director of Energy Market Operations Philip D'Antonio said in an affidavit.

Philip D'Antonio, PJM | © RTO Insider LLC

FERC approved a PJM request to remove the TCPF in Virginia's Northern Neck peninsula after one of the three transmission lines into the region was placed on an outage for upgrades. The tariff and OA revisions were limited to that region, but the commission encouraged PJM to "consider modifications to its analyses of and planning for transmission outages to prevent such occurrences in the future." (See *FERC Approves Pause of PJM Tx Constraint Penalty Factor in Va.*)

The PJM Markets and Reliability Committee approved the revisions during its Nov. 16, 2022, meeting. (See "TCPF Adjustments Permitted for Issues with Ongoing Solution," *PJM MRC Briefs: Nov. 16, 2022*.)

DC Energy submitted comments to the proposal asking that the commission condition any approval on requiring that PJM provide market participants notice of any changes to the TCPF, as well as the specific outage, facilities and constraints prompting the reduction.

The Independent Market Monitor objected to the proposal, arguing that it lacks a verifiable process for PJM to follow when implementing the change and that no amount of data can be made available to provide the transparency needed to ensure that the RTO is applying the rules consistently. The IMM asked the commission to reject the filing and require PJM to create new rules that more accurately reflect transmission operating limits and forward-looking dispatch tools.

The Monitor also said that PJM and the commission should be eliminating instances in which the RTO has the discretion to set prices, in this case by choosing a marginal unit and modifying the TCPF to set LMPs. In the case of transmission upgrades that might cause congestion, the Monitor argued that transmission operators should create practices that ensure reliability throughout construction.

FERC said that PJM's tariff already contains language requiring the notifications sought by DC Energy. It also sided with PJM over the Monitor, agreeing with the RTO that the proposal would not grant it considerable discretion and that it would only be allowed to reduce penalty factors in the specific circumstances outlined. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

PJM Gives Update on December Winter Storm Report

VALLEY FORGE, Pa. — Adam Keech, PJM vice president of market design, told the Markets and Reliability Committee last week that the RTO is delaying its estimation of when it will be publishing a report on the December winter storm to July.

In committee meetings following the storm, also known as Winter Storm Elliott, PJM initially stated that it was planning to release the report in April. But Keech said that staff are diverting resources to a data request related to the storm from NERC and FERC, followed by a visit from the two organizations in April. Staff are also working to address a list of compliance filings FERC required in its conditional approval of PJM's proposal to allow aggregated distributed energy resources to participate in its markets.

Adam Keech, PJM | © *RTO Insider LLC*

The report will likely be structured similarly to the paper PJM released following the 2014 polar vortex, with chapters on generation performance and gas availability, load forecasting, timing and criteria for emergency procedures, Capacity Performance, dispatch, and the cost offer verification process.

In the meantime, Keech said PJM plans to provide lessons learned from the storm during stakeholder meetings in mid-May, focusing on the capacity market to inform changes being considered through the Critical Issues Fast Path (CIFP) process. He said many of the major items that will likely be presented have already been under stakeholder discussion even before the December storm. (See *PJM Board Initiates Fast-track Process to Address Reliability*.)

"We've been working on many of the issues you will see already for the past year," he said.

Stakeholders Support New Default CONE and ACR Values

Both the MRC and Members Committee supported the *proposed* default cost of new entry (CONE) and avoidable-cost rate (ACR) through advisory votes. The changes are now set to be filed with FERC, with the goal of being in place for the 2026/27 delivery year. PJM elected for a same-day vote for the MRC and MC to give the Board of Managers more time to review the information before the filing. (See "Updated Default CONE and ACR Figures," *PJM MRC/MC Briefs: Feb. 23, 2023*.)

The gross CONE values for all resource types, except storage, would increase, which PJM's Skyler Marzewski said is largely because of changes to investment tax credits under the Inflation Reduction Act. The CONE changes also include new reference resources for combined cycle and onshore wind resources.

The most significant changes to ACRs include adding steam oil and gas as a new default unit type, including more data from the Nuclear Energy Institute for calculating nuclear costs and refined estimates of property taxes and insurance costs. All gross ACR values increased except single-reactor nuclear facilities.

PJM, Monitor Present Renewable Dispatch Proposal

Joel Romero Luna of Monitoring Analytics and PJM's Darrell Frogg presented a first read of a joint *proposal* to create new dispatch protocols for renewable resources, with the aim of increasing visibility of what level renewables can be reduced to. Frogg said as more intermittent resources come online, it is likely that there will be more dispatch required, and those resources will not be able to provide their maximum output whenever they are available.

The proposal would use basepoints currently available through the Inter-Control Center Communications Protocol (ICCP) rather than curtailment flags, and intermittent resources would be directed to follow their economic basepoints even when they are curtailed because of the prevalence of inadvertent curtailments. Resources would be required to update critical parameters in real-time security-constrained economic dispatch (SCED) every five minutes and on an hourly basis for parameters in intermediate-term SCED cases.

The current lost opportunity cost (LOC) structure for wind resources would be extended to solar generators, making them eligible for LOC when they follow SCED dispatch and have the ability to receive instructions from PJM.

Frogg said the proposal is an effort to require intermittents to offer their median or expected output into the day-ahead market, based on forecasts of both weather and equipment availability.

Responding to stakeholder questions, Luna clarified that there is currently a requirement that units must offer into the market, and while most intermittents already follow the practice being proposed, there is insufficient clarity in the manuals codifying the process.

Economist Roy Shanker questioned how generators' forecasts will be reviewed for accuracy by PJM, saying that outside forecasts should be checked for accuracy to avoid a bias being developed.

Monitor Joe Bowring said they believe the right amount of review is already included in the proposal and no further changes are needed.

Members Committee

Deficiency Notice Interrupts Timeline on CP Penalty Payments

Just the day before the committee meetings, FERC issued a deficiency notice on PJM's filing to allow market participants that have defaulted to continue operating in its markets under certain conditions, including their contribution to reliability, the ability to generate revenues in the future and capability to post collateral (*ER23-1058*).

A fourth factor recognizes that certain transmission customers cannot have their service terminated without FERC approval. (See "1st Read on Proposal to Allow Flexibility for Market Participation During Defaults," *PJM MRC Briefs: Nov. 16, 2022*)

The notice "is of concern for those following Winter Storm Elliott, because we are getting ready in April to send out the invoices for the Capacity Performance penalties," PJM General Counsel Chris O'Hara told the MC.

In its *response* to the notice, filed Thursday, the RTO said it had accidentally included the last four words in the phrase, "PJM may permit a defaulting market participant to continue to participate in PJM markets in a limited manner," in the proposed revisions to the Operating Agreement; they had been in an early draft but deemed too vague — as FERC noticed — and were meant to be removed.

PJM also stated that the four factors it identified consisted of an exhaustive list of the circumstances under which it would allow market participants to continue operating while in default.

The RTO asked FERC to implement a shortened five-day comment period and to rule on the proposal by April 7, with an effective date of April 8.

"PJM requested these dates purposefully," the RTO said in its response. "PJM is required to issue the March monthly bill by April 7, 2023. Those monthly bills will include any nonperformance charges related to Winter Storm Elliott. The aggregate nonperformance charge will be between $1 [billion] to $2 billion. While PJM has proactively acted to reduce the risk of capacity market seller default by proposing to amend the manner in which the Winter Storm Elliott nonperformance charges may be billed, the risk of default will remain, even if those revisions are accepted," referring to a separate filing that would allow market participants to opt to make their payments over a longer period.

O'Hara said PJM is concerned about the possibility of defaults stemming from the nonperformance charges, not just in terms of the absolute number of megawatts affected, but also the potential for generators providing critical services such as black start or critical load units being at risk. Should owners of those facilities be considering default, he said PJM wants a conversation to be opened so that they can seek a waiver request at FERC to allow them to continue operating.

Stakeholders Question CIFP Process

Steven Lieberman of American Municipal Power said he believes the PJM board has not met the requirements for initiating the CIFP process that it began in February, arguing that it has not set a firm deadline for resolving the issue.

While the board has identified Oct. 1 as the date for PJM to make a filing to address reliability concerns identified in about five years, Lieberman argued that the deadline is arbitrary. (See *PJM, Stakeholders Present Initial Capacity Market Proposals to RASTF*)

"It's our opinion at least that it doesn't satisfy the requirements for starting the CIFP process in the first place. ... We think this process was elected in a way that conflicts with Manual 34," he said.

Lieberman also said the board's letter opening the CIFP is vague and does not lay out a process that fosters the kind of open and transparent dialogue that the letter states the board hopes to have with stakeholders as they create proposals. He noted that stakeholders had requested that the board attend future MRC or MC meetings to speak about the scope it envisioned for CIFP proposals and what its largest concerns are, but that PJM determined it would not be proper to have individual members potentially speaking on behalf of the entire board.

Greg Poulos, of the Consumer Advocates of the PJM States (CAPS), said generator performance is the key issue for many state advocates, but he believes it will be hard to create a proposal addressing the issue when the data on performance during Elliott won't be available until July.

"When you look at what our dates are and what we're trying to achieve, it is hard to match it up," he said.

Susan Bruce, representing the PJM Industrial Customer Coalition, agreed that the deadlines are optimistic, and attempting to address too many portions of the capacity market on a short time frame may prove difficult. She said stakeholders should have a disciplined mindset rather than allow the process to become "an invitation for a Christmas tree."

Erik Heinle, Vistra's director of PJM market policy, said he believes the board letter was well written and provides enough clarity on the areas it believes that proposals must address, while also leaving stakeholders discretion to include other topics as well. He noted that any issues not addressed by the CIFP could be open for continued discussion through the Resource Adequacy Senior Task Force, which is currently on hiatus through the CIFP deliberations.

Other Stakeholder Discussions

MC Chair David "Scarp" Scarpignato said stakeholders are considering whether to start MC meetings earlier on days when the MRC adjourns significantly earlier than scheduled. He said that in some cases, stakeholders must wait for hours before the MC starts. Those with comments or suggestions were encouraged to reach out to Scarp or PJM Director of Stakeholder Affairs David Anders.

The MRC tabled a vote on proposed *revisions* to Manual 11: Energy & Ancillary Services Market Operations because of amendments offered in an attempt to better align the manual with PJM's other governing documents. Monitor Bowring and some stakeholders suggested that the proposed changes to the revisions may be substantive at first glance and it would be better to wait a month to review before taking a vote. ■

— Devin Leith-Yessian

Company Briefs

Sempra to Build $13B LNG Facility in Port Arthur

Sempra Infrastructure last week announced it will build a $13 billion LNG facility in East Texas.

Sempra also said it closed its joint venture with ConocoPhillips, which agreed to buy more than a third of the Port Arthur LNG project's annual production and a 30% stake in the development. KKR, which owns 20% of Sempra Infrastructure, also agreed to buy a non-controlling interest in the project, the companies said.

The company said it aims to launch the 13.5-million-metric-ton facility in 2027.

More: *Houston Chronicle*

Ford: EV Unit Losing Billions

Ford's electric vehicle (EV) business lost $3 billion before taxes over the past two years and will lose a similar amount this year as the company invests heavily in the new technology.

The figures were released last week as Ford rolled out a new way of reporting financial results. The new business structure separates EVs, internal combustion and commercial vehicle operations into three units.

Company officials said the EV unit, called "Ford Model e," should be profitable before taxes by late 2026 with an 8% pretax profit margin.

More: *The Associated Press*

Electrolyzer Manufacturer HydrogenPro to Build Facility in Texas

Norway-based electrolyzer manufacturer HydrogenPro last week announced plans to bring a production facility to Texas.

The company plans to invest up to $50 million in the facility, which will be developed on an existing industrial site. It is expected to launch within the next year.

Electrolyzers are pieces of equipment that use electricity to split water into oxygen and hydrogen — items in high demand for companies that make hydrogen as an alternative fuel.

More: *Houston Chronicle*

Entek Plans $1.5B Project in Indiana

Battery parts producer Entek last week said it plans to invest $1.5 billion in a new manufacturing campus in Terre Haute, Ind.

Plans for the project include four buildings totaling 1.4 million square feet in the Vigo County Industrial Park.

The company makes battery separators for lithium-ion battery manufacturers.

More: *The Associated Press*

Albemarle to Build $1.3B Lithium Plant in South Carolina

Albemarle last week announced that it has chosen Chester County, S.C., as the location for a $1.3 billion lithium processing plant.

The facility is expected to double the company's lithium processing capacity and process 50,000 tons of lithium a year.

Construction of the 800-acre project is expected to begin late next year.

More: *Reuters*

Federal Briefs

Biden Issues First Veto, Rejects Bill Reversing ESG Rule

President Joe Biden last week issued his first veto since taking office, rejecting a bill that would have reversed a Labor Department rule on environmental, social and governance (ESG) investing.

The Biden administration previously had issued a rule stating that money managers can weigh climate change and other ESG factors when making decisions for retirement investments. It replaced a rule from former President Donald Trump that the Biden administration said discouraged consideration of ESG factors "even in cases where it is in the financial interest of plans to take such considerations into account."

Later in the week, the Republican-led House failed to override the veto, falling short of the two-thirds majority needed to revive the resolution.

More: *The Hill*, *The Hill*

TVA's Next-gen Nuke Reactor Will Open at Clinch River Site in Oak Ridge

The Tennessee Valley Authority last week announced it will introduce the next generation of nuclear power at its Clinch River site.

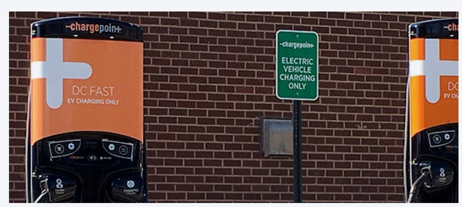
As part of an agreement, TVA will work with GE Hitachi Nuclear Energy, Ontario Power Generation and Synthos Green Energy to finance and design a new small modular reactor. If successful, these reactors could be deployed in the U.S., Canada and Poland.

The total combined investment from the four companies is about $400 million.

More: *Knoxville News Sentinel*

DOT Announces $2.5B in Grants for EV Chargers in Underserved Areas

The Department of Transportation last week announced $2.5 billion in new grants for the construction of electric vehicle charging stations and alternative fueling infrastructure aiming, in part, at increasing access in underserved neighborhoods and communities.



Known as the Charging and Fueling Infrastructure program, the grants will be awarded over a five-year period, with an emphasis on both highway chargers and locations in traditionally underserved and disadvantaged urban, rural and tribal communities. The funding builds on a separate $5 billion in federal money dedicated to growing a nationwide network of chargers along highways.

The department did not specify how many chargers it expects to help build.

More: *The Associated Press*

State Briefs

ARKANSAS

AG Urges PSC to Investigate Summit Utilities' Billing Practices

Attorney General Tim Griffin last week filed a petition urging the Public Service Commission to open investigations into the billing and gas-purchasing practices of Summit Utilities.

Griffin urged the PSC to investigate more than 2,800 customer complaints he has received. Most were centered on billing errors and gas prices. Customer problems are said to have begun soon after the company converted the billing systems of CenterPoint Energy Resources to Summit's systems.

A PSC spokesman said the agency would respond to Griffin's petition through its standard review processes. Summit said it will work with the commission on the process.

More: *Arkansas Democrat Gazette*

FLORIDA

Proposed Bill Would Impose EV Fee to Make Up for Lost Gas Tax

The Senate Transportation Committee last week passed a bill that would impose an additional yearly license plate registration fee of $200 on electric vehicles (EVs); plug-in hybrids would be charged an additional $50. Both would increase by $50 in 2028.

Ananth Prasad, president of the Florida Transportation Builders Association, cited a legislative analysis that shows local and state governments are losing $58 million a year due to a loss of gas tax revenue.

If approved, the bill would take effect July 1.

More: *WUSF*

INDIANA

Governor Signs Bill Upending Supreme Court Case over Duke Coal Ash Waste

Gov. **Eric Holcomb** last week signed a bill into law that will undo the effect of a Supreme Court decision over Duke Energy's coal ash waste and allow utilities to recover "unexpected" additional costs from their customers.

Duke's costs to comply with federal rules on coal ash cleanup were more expensive than it planned, and even though it budgeted for those costs, the utility asked the Utility Regulatory Commission if it could raise rates in 2019. The URC approved the increase, but the state Supreme Court later ruled it "retroactive ratemaking," which is illegal. However, the new law will let utilities recover the extra costs that come with complying with federal rules without having to get pre-approval — if the IURC approves them after the fact.

The law will not allow utilities that retire coal plants earlier than planned raise rates to pay off the cost of those plants in a shorter time frame.

More: *Indiana Public Radio*

Senate Unanimously Passes Energy Plan

The Senate last week unanimously passed a bill that would create a statewide energy plan.

The bill instructs the Utility Regulatory Commission to consider reliability, affordability, resiliency, stability and environmental sustainability when: (1) reviewing and preparing a final director's report for an integrated resource plan submitted by a utility; (2) acting upon a petition for the construction, purchase or lease of a generation facility; and (3) reviewing whether the public convenience and necessity continues to require the completion of a generation facility under construction.

The bill also cuts in half the amount of power utilities can buy from the grid during peak demand.

More: *WVPE*, *Indiana General Assembly*

IOWA

House Passes Bill to Restrict Eminent Domain for Pipelines

The House last week passed a bill that will require carbon dioxide pipeline companies to obtain voluntary easements for 90% of their pipeline routes before they can use eminent domain.

The bill also would expand landowners' ability to get compensation for crop yield damages that result from pipeline construction and would create a study committee to evaluate current eminent domain regulations. House lawmakers did amend the bill, removing other restrictions on the projects, including one that would have empowered counties to set rules about where the pipelines can be built.

The bill is expected to face an uphill battle in the Senate.

More: *Iowa Capital Dispatch*

KANSAS

House Votes to Block ESG Investments at all Gov't Levels

The House last week voted 85-35 to amend a law that would force the Public Employees Retirement System to concentrate on the fiduciary duty of maximizing monetary gain with a portfolio serving teachers and other government workers without giving any weight to environmental, social or governance criteria when signing contracts.

The bill would make it illegal to give preference or to discriminate against specific businesses, including those engaged in nuclear, oil, coal or natural gas operations, agriculture production, forestry, mining, and firearm and ammunition manufacturing.

The bill now heads to the Senate.

More: *Kansas Reflector*

MICHIGAN

Genoa Township Imposes 6-Month Moratorium on Commercial Solar

The Genoa Township Board of Trustees last week unanimously adopted a six-month moratorium on applications for construction of ground-mounted or commercial solar projects.

The board previously had passed a moratorium resolution and introduced a moratorium ordinance at its March 6 meeting that put a 30-day moratorium in effect to give the planning commission time to research and recommend potential ordinance changes regarding solar. The board then extended the moratorium.

More: *Livingston Daily*

MINNESOTA

Radioactive Water Leaks at Monticello Nuclear Plant for 2nd Time

Water containing a radioactive material has leaked for a second time from the Monticello Nuclear Generating Plant, and the plant will be shut down. But there is no danger to the public, plant owner Xcel Energy said last week.

A leak of what was believed to be hundreds of gallons of water containing tritium was discovered at a temporary fix, where 400,000 gallons of water with tritium leaked in November. There was a monthslong delay in announcing the initial leak that raised questions about public safety and transparency, but industry experts said there was never a public health threat.

Tritium is a radioactive isotope of hydrogen that occurs naturally and is a common byproduct of nuclear plant operations. It emits a weak form of beta radiation that does not travel far and cannot penetrate human skin, according to the Nuclear Regulatory Commission.

More: *The Associated Press*

NORTH CAROLINA

Bill Would Up Costs for Electric, Hybrid Ownership

Several state lawmakers introduced a bill last week that would increase registration fees for electric and hybrid vehicles.

According to Sen. Vickie Sawyer, the DOT has faced financial troubles in past years and there is a major need for funding to keep roads and infrastructure up to standard. The discrepancy of the cost fuel-consuming vehicles are paying compared to EV and hybrids means even though these vehicles are using the same roads, they're not paying into the transportation fund as much as others.

More: *WBTV*

OHIO

Marion County Approves Wind Energy Restrictions

The Marion County Board of Commissioners last week voted 3-0 to approve a resolution restricting the development of wind energy projects in Grand Prairie Township.

The measure prohibits the construction of an "economically significant wind farm and/or large wind farm" as defined in the state's Revised Code. The restriction applies to all unincorporated areas of the township.

Grand Prairie is the ninth township in Marion County to enact restrictions on the development of renewable energy projects but is the first to place limits only on wind energy.

More: *Marion Star*

OREGON

Supreme Court Clears Idaho Power Tx Line

The state Supreme Court last week upheld an Energy Facility Siting Council decision granting Idaho Power permission to move forward with a 290-mile, 500 kV transmission line between Boardman and the company's Hemingway substation in Owyhee County.

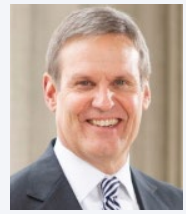
The justices said the council did have the authority to grant exemptions and that opponents did not present any "legal error" in the way the project's impacts to landscape were evaluated. Amendments to the project remain under review, and a mitigation plan still needs to be finalized by the utilities and state and federal agencies. The Public Utility Commission also needs to issue a decision on Idaho Power's application for a certificate of public convenience and necessity.

Idaho Power hopes to begin construction later this year, with a target for operations in 2026.

More: *Boise State Public Radio*

TENNESSEE

Senate Passes $3B Transportation Plan



The Senate last week voted 26-5 to pass Gov. **Bill Lee's** transportation plan that would funnel more than $3 billion into infrastructure projects.

The bill institutes new EV fees to offset lost gas taxes. The fees would be paid with registrations and would be $200 until 2027 and then rise to $274. Sen. Brent Taylor said drivers could face a 93-cent gas tax increase to fund road updates without Lee's plan.

If approved by the House, each of the Department of Transportation's four regions would receive $750 million to cover infrastructure issues.

More: *Nashville Tennessean*

WISCONSIN

PSC Approves Utilities' Purchase of Koshkonong Solar Energy Center

The Public Service Commission last week approved the $649 million purchase of the Koshkonong Solar Energy Center by We Energies, Wisconsin Public Service and Madison Gas and Electric.

The state's largest renewable energy plant, which was approved for construction last year, would sit on 4,600 acres and provide 300 MW of solar power with 165 MW of storage. We Energies and WPS will own 90% of the plant while Madison Gas and Electric will own 10%.

The utilities, which aim to cut carbon emissions by 80% below 2005 levels by the end of the decade and go carbon-neutral by 2050, are buying the solar plant from Invenergy.

More: *Wisconsin Public Radio*