# RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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# Biden to Nominate Phillips to FERC

### *DC PSC Chair Would Fill Chatterjee's Seat, Give Democrats Majority*

*By Michael Brooks*

The White House on Thursday *announced* that President Biden intends to nominate D.C. Public Service Commission Chair Willie Phillips to FERC.

D.C. Public Service Commission Chair and MACRUC President Willie Phillips presides over MACRUC's annual conference in June in Pennsylvania. | *© RTO Insider LLC*

Phillips, a Democrat, would fill the seat previously held by Republican Neil Chatterjee, who departed Aug. 30 after his term ended June 30. Phillips' term would end June 30, 2026. His confirmation would give FERC a Democratic majority for the first time in Biden's presidency and until at least 2025 — presuming Chair Richard Glick or Commissioner Allison Clements do not resign before the end of their terms.

"As the Biden administration works to tackle the climate crisis, advance environmental justice and create a clean electricity grid by 2035, FERC will maintain an important role regulating the transmission of carbon-free energy across the country," the White House

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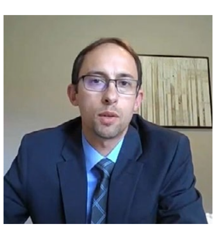
**Trump-era FERC Chair Reflects on Tenure**
(p.4)

# FERC Workshop Participants Differ on GETs Incentives

*By K Kaufmann, Tom Kleckner, Michael Kuser and Jason York*

Participants at FERC's *workshop* Friday on performance-based ratemaking approaches universally support grid-enhancing technologies (GETs), but they disagree on how best to foster their adoption by transmission owners and RTOs/ISOs (RM20-10, AD19-19).

A shared savings incentive *proposal* by the WATT Coalition and Advanced Energy Economy drew praise from tech providers and regulators but doubts from some grid operators and others. (See related story, *WATT Coalition Previews GETs Proposal Before FERC Workshop*.)

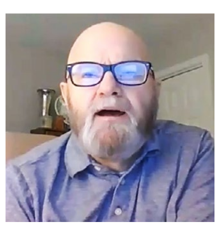


Mitchell Myhre, Alliant Energy | *FERC*

FERC should mandate grid operators to include GETS in their planning processes, said Mitchell Myhre, manager of transmission planning and regulatory affairs for Alliant Energy. "I don't think this can be an add-on role that is built on top of existing resources."

GETs are "the direction that the industry must take," said Judy Chang, undersecretary of energy for the Massachusetts Executive Office of Energy and Environmental Affairs.

The WATT "proposal is shining a spotlight on the fact that grid-enhancing technologies are available but are not being deployed in our current transmission planning and investment framework," said Katie Dykes, commissioner of Connecticut's Department of Energy and Environmental Protection.



Doug Bowman, SPP | *FERC*

Not so fast, said Douglas Bowman, SPP lead engineer for research, development and tariff

*Continued on page 5*

# Illinois Senate Passes Landmark Energy Transition Act

### *Includes Bailout for Exelon Nuclear Plants*

*By John Funk*

By a razor-thin margin the Illinois Senate approved *landmark legislation* Monday putting the state on a 30-year path to 100% carbon-free electric generation and bailing out two troubled nuclear power plants.

Nearly three years in the making, the controversial Energy Transition Act now goes to Gov. J.B. Pritzker, who said last week that he would sign the nearly 1,000-page bill if lawmakers could get it to his desk.

The Illinois House of Representatives

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*See p.29 for this week's coverage.*

FERC/Federal News

# Biden to Nominate Phillips to FERC

## *DC PSC Chair Would Fill Chatterjee's Seat, Give Democrats Majority*

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said. "As chairman of the Public Service Commission of the District of Columbia, Willie was a thoughtful and innovative leader in modernizing the energy grid, implementing the district's aggressive clean energy and climate goals, and in protecting the district's customers."

Phillips has served on the D.C. PSC since 2014 and was re-nominated and appointed chair in 2018 by Mayor Muriel Bowser. He is also president of the Mid-Atlantic Conference of Regulatory Utility Commissioners. (See *Overheard at MACRUC 2021: Pandemic Hardships*.)

Prior to becoming a commissioner, he worked at D.C.-based law firm Van Ness Feldman before joining NERC for nearly five years, eventually becoming an assistant general counsel. A native of Alabama, he earned his undergraduate degree from the University of Montevallo and served as deputy press secretary for Sen. Jeff Sessions (R-Ala.) from 2000 to 2002.

### Likely a Matter of 'When,' not 'If'

ClearView Energy Partners said Biden's choice of Phillips was pragmatic and that he is unlikely to face any major opposition in the Senate. It noted that his experience at NERC would likely help him with Republicans, who generally place grid reliability at the forefront of FERC's responsibilities. His service under Sessions could also help him earn bipartisan points, the analysts said.

"The nomination of Phillips may be a move to recognize that the commission is an independent *economic* regulator, not an *environmental* regulator," ClearView said. "That said, we do expect Phillips to support FERC facilitating the federal policies under development elsewhere in the administration (such as at the Environmental Protection Agency and the Council on Environmental Quality) to facilitate the Biden agenda for an energy transition."

Phillips with former FERC Commissioner Neil Chatterjee at the MACRUC conference | *Neil Chatterjee via Twitter*

"I look forward to meeting with Willie Phillips and having him appear before the Senate Energy and Natural Resources Committee," Sen. Joe Manchin (D-W.Va.), chair of the committee, said in a statement. "Just as I do with each of the nominees that come before the committee, I will carefully examine his record and qualifications to serve in this important role overseeing our federal energy policy."

Still, ClearView noted that the Senate has a lot on its plate, and that it did not expect Phillips to be seated earlier than November. Along with legislation implementing budget reconciliation, the Senate will likely be focused on yet another battle over the debt ceiling. Treasury Secretary Janet Yellen on Wednesday warned Congress that the U.S. could default on its debt as soon as next month if the ceiling isn't raised.

### Reaction

The choice of a local regulator, particularly one from the PJM footprint, may also be intended to diffuse tension between FERC and the states over controversial matters such as the RTO's minimum offer price rule.

The National Association of Regulatory Utility Commissioners was particularly enthusiastic about the choice, noting that it believes all FERC commissioners should have state regulatory experience. "We wholeheartedly support the nomination of Chairman Phillips to serve as a FERC member. He possesses extensive knowledge of the critical issues facing regulators today," Executive Director Greg White said. "There is no doubt that he will apply this balanced, thoughtful approach to his new role as a FERC commissioner."

The news was met with mostly positive reaction from around the industry. The American Council on Renewable Energy, Advanced Energy Economy, the Solar Energy Industries Association and the Electric Power Supply Association, among many other groups, all released statements congratulating Phillips and urging the Senate to quickly confirm him.

Glick and Chatterjee also congratulated Phillips, with Chatterjee *tweeting* that "it would be an honor to have him succeed me."

Environmental organizations, however, were tepid, at best. A coalition of nearly 500 of them had written to Biden and Senate leaders last month encouraging them to appoint "an environmental and energy justice champion" to fill Chatterjee's seat.

"We're deeply concerned about whether the new commissioner will be too closely tied to the energy utilities that have put profit above people," said Jean Su, energy justice director and senior attorney for the Center for Biological Diversity, one of the lead signatories to the letter. "We hope the Senate will ask the tough questions of Mr. Phillips about his commitment to ending FERC's disastrous status quo so we can finally prioritize environmental and energy justice in our energy policies." ■

FERC/Federal News

# Trump-era FERC Chair Reflects on Tenure

## *Chatterjee 'Cautiously Optimistic' RTO Carbon Price Proposal Coming to Commission Soon*

*By Michael Brooks*

Neil Chatterjee | *© RTO Insider LLC*

Neil Chatterjee's four years at FERC, most of them at the helm, transformed him from playing the partisan game of thrones to advocating for a price on carbon as a way to solve the problem of climate change.

A Republican who worked as an adviser to Sen. Mitch McConnell (R-Ky.) prior to being appointed to FERC by President Donald Trump, Chatterjee maintains he has always thought climate change is a serious problem. But in recent interviews about his time at the commission — including one with *RTO Insider* last week, he has repeatedly expressed regret about his first stint as chair.

Chatterjee's term ended June 30, and he resigned Aug. 30 to join law firm Hogan Lovells. President Biden last week announced he intends to nominate D.C. Public Service Commission Chair Willie Phillips to be his successor. (See *Biden to Nominate Phillips to FERC*.) Chatterjee spoke to *RTO Insider* on Sept. 7, prior to Biden's announcement.

"It took me a while to grow into the job," Chatterjee said. "In my initial days with the commission, I really struggled to make the transition from partisan legislative aide to independent regulator." That was most publicly visible, he said, when he "admittedly mishandled" a proposal from Energy Secretary Rick Perry in late 2017 to order RTOs and ISOs to compensate generators for their on-site fuel costs. At the time, Chatterjee praised Perry's "bold leadership" and was supportive of the proposal, as it would have aided struggling coal communities in his native Kentucky.

"That was a serious issue that I injected a political element into; that was a mistake," he said last week. "I think I got thrown into the deep end of the pool without knowing how to swim. [So] I actually think I grew from that experience."

After former FERC Chair Kevin McIntyre relinquished his leadership role for health reasons in 2018, Chatterjee said it was McIntyre who was instrumental in that growth. With McIntyre as chair and a full complement of five commissioners, Perry's proposal was unanimously rejected. Reappointed chair after McIntyre resigned, Chatterjee told reporters that McIntyre "could not be more strenuous in saying that politics could not be allowed to interfere with the work of the commission." (See *Returning Chair Pledges to Protect FERC's Independence*.)

After the experience of the Perry proposal and having learned from McIntyre's leadership, Chatterjee said he became "a more focused regulator [with] a team around me that would really give me the soundest advice." He began to increasingly speak out about market-based solutions to climate change, culminating in a policy statement in late 2020 inviting states to introduce carbon pricing in RTOs. (See *FERC: Send Us Your Carbon Pricing Plans*.)

That move ultimately cost him the chair. Shortly after the *Washington Examiner* published an *article* titled "Trump appointee becomes leading climate problem solver," Trump fired Chatterjee and promoted Commissioner James Danly, who served in the top job until Biden took office and appointed Commissioner Richard Glick. According to Chatterjee, his post-chair tenure "was some of the most fun that I had at the commission. … I no longer had the burdens of the chairmanship to contend with, but I was invested in making sure there was a successful transition to Chairman Glick."

### Carbon Price Advocate

Along with Hogan Lovells, where he will advise clients on energy markets, Chatterjee also joined The Climate Leadership Council and its lobbying unit, Americans for Carbon Dividends. According to the organization, "Chatterjee will draw on his deep experience to help the council refine the details of its comprehensive policy initiative to price carbon emissions and return the revenues to all Americans."

"I've seen firsthand the difficulty of trying to navigate a patchwork of state policies while maintaining market efficiencies," he said. "I've really come to the conclusion that a price on carbon is the most effective way to drive down emissions and bridge this gap between" state policies and markets.

It's safe to say many economists would agree with him, but the idea has not gained traction in Congress. Chatterjee said he hopes to change that.

"Part of it is looking at what are the alternative options are," he said. "When compared to alternative solutions that are more onerous and may lead to greater threats to reliability and may not be efficient from a market standpoint, I think you may see some more interest" in a carbon price.

He's also "cautiously optimistic that we're pretty close to seeing an RTO or an ISO come to FERC" with a carbon pricing proposal. If approved, "I am of the belief that such an approach would lead to market efficiencies and a reduction in carbon [emissions]. So it's possible that having that kind of a lab experiment in an RTO or ISO, if it proves to be successful … that could be the type of thing that helps build public support; we could point to an example. … Some have deemed that a 'baby step.' … Let's take the baby step and see what happens." ■

FERC/Federal News

# FERC Workshop Participants Differ on GETs Incentives

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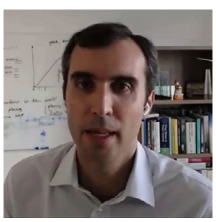
studies.

SPP staff have worked on dynamic line ratings, power flow control and topology optimization projects that they believe provide reliability and economic benefits, but the challenge comes in "getting buy-in" for the new technologies from market participants and stakeholders, Bowman said.

"It's not that we don't want these devices on our system," Bowman said. New technologies have "to go through an approval process before we can implement [them], and we have to ensure that we have that long-term technological resilience that's wired."

All new technologies need additional study to ensure that an overlapping installation does not introduce adverse impacts on reliability, said Eric Hsia, manager of applied innovation at PJM.

## Carrot or Stick



Pablo Ruiz, NewGrid | *FERC*

Without an incentive for GETs, utilities would work on projects for which they're already incentivized: high-capital projects that would have a lot of benefits, NewGrid CEO Pablo Ruiz said. "It's almost like having to choose between consumers and shareholders and prioritizing your staff resources."

GETs are simply another solution in the toolbox, said Jeremiah Doner, MISO director of economic policy and planning.

"We should look at it the same way we look at a new transmission line or substation … how to most effectively address the issue that we're trying to fix," Doner said. "Focusing on adjusted production costs … is a very narrow metric that's just focused on congestion relief around production costs. Flow-control devices address reliable issues [and] could be a deferred, more cost-effective way to address a long-term reliability issue."

The commission should consider market-tbased approaches that compensate GETs based on the actual value that they generate in the market, rather than forecasting the benefits they may have, said David Patton, president of Potomac Economics, market monitor for ERCOT, ISO-NE, MISO and NYISO.

At present, no RTO or ISO has "the ability to operate these kinds of devices, so the idea of requiring them to quantify the benefits of that sort of device is definitely a cart-before-the-horse idea," Patton said. "Tremendous work needs to be done with the planning models, modeling a wider array of conditions than they've ever modeled before. The planning models, even right now, don't do a good job of quantifying the value of, for instance, battery technologies."

Yachi Lin, NYISO | *FERC*

Some GETs offer great benefits on the controllability side, enabling grid operators to direct power flows one way or another, but how can one quantify controllability? asked Yachi Lin, senior manager of transmission planning at NYISO.

"I'm struggling with … how do we quantify that additional benefit on top of that performance?" Lin said.

Planning processes at PJM already allow for GETs "to be offered and to be considered and to compete" in wholesale markets, according to Suzanne Glatz, the RTO's director of strategic initiatives and interregional planning.

PJM's concern was that the proposed shared savings incentives would not necessarily be "derived directly from the cost but actually are kind of blurring the lines between markets, value and how that would affect the project cost." As a result, the planning process could be turned into a forum for discussing ratemaking issues," Glatz said.

## End Game

There are limited alternative approaches, said former FERC Chair Jon Wellinghoff, now head of GridPolicy Consulting. "I've thought about this long and hard as to how to get these technologies incorporated into a transmission system in our country that is very inefficient and that needs to have efficiency improved drastically."

FERC could mandate that RTOs and ISOs incorporate GETs into their planning processes, but experience shows mandates are "not the best way" to get RTOs and ISOs to act as quickly and efficiently as possible, Wellinghoff said.

Planners need to make sure not to let perfect be the enemy of the good, said Hudson Gilmer, CEO and founder of LineVision. "I think there is an imperative to take action on the part of the commission: a legal imperative as well as a climate imperative."

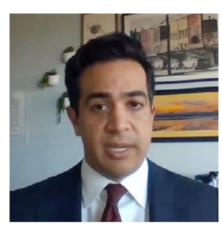
Grid Strategies President Rob Gramlich | *FERC*

Congress gave FERC a mandate 16 years ago to incentivize technologies that increase the capacity and efficiency of existing transmission facilities and improve their operations, said Rob Gramlich, executive director of the WATT Coalition. Given the successful deployments of GETs abroad, it is time for FERC to act, he said.

European transmission system owners balked at GETs 10 years ago, but now they clamor for "more and more and more," said Victor le Maire of Elia, the grid operator for Belgium.

What does FERC see as the end game? asked Steve Leovy, transmission engineer at WPPI Energy. "If we institute shared savings, is that going to go on forever? Or are we doing that during an interim period when we're expecting something else to develop?"

Look to the commissioners' statements, said Samin Peirovi, FERC analyst who moderated the all-panelists roundtable to close the day.



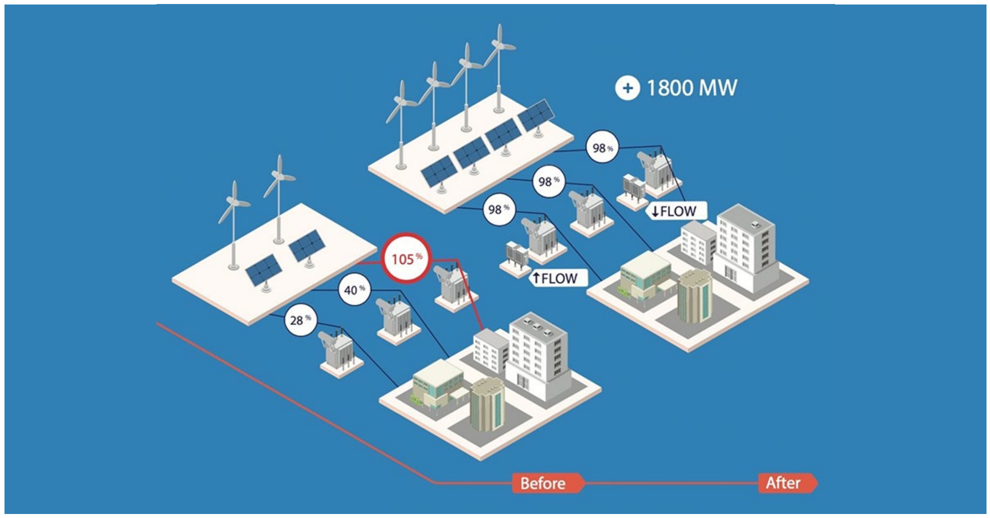
Samin Peirovi, FERC | *FERC*

"I do not speak for the commission, but I think the questions we hit on in every panel kind of speak to our interest in the shared savings approach and transmission technologies in general," Peirovi said. "If you talk about a paradigm where eventually we see the level of deployment that's a little more than status quo, that would be great, but how we get there and how we balance the interest between ratepayers and developers is exactly why we're having this discussion." ■

## FERC/Federal News

# WATT Coalition Previews GETs Proposal Before FERC Workshop

By Michael Kuser




The WATT Coalition recommends several grid-enhancing technologies, such as Advanced Power Flow Control, which together can lead to estimated savings of up to $2 billion per year. | *WATT Coalition*

Advocates of grid-enhancing technologies (GET) said Wednesday that regulators should adopt a "shared savings" model to persuade utilities to adopt low-cost investments that could free up crucial transmission capacity.

The first step is to distinguish shared savings from the way that costs are recovered in the industry, which is return on equity and the standard approach to incentives that FERC has used.

Rob Gramlich, executive director of the Working for Advanced Transmission Technologies (WATT) Coalition, told a press briefing that traditional return on equity ratemaking won't work for GETs.

"Return on equity is of course based on how much capital is invested, and if we're talking about very low cost very low capital deployments, then it doesn't matter how high the ROE incentive is, it's not going to make a difference," Gramlich said. "It's just not the right metric."

The WATT Coalition called the briefing to build support for its proposed model, which was the subject of discussion at a FERC *workshop* on shared-savings incentives Friday (RM20-10, AD19-19).

The coalition is made up of technology providers who support greater deployment of grid technologies such as dynamic line ratings, power flow control and topology optimization. The coalition includes Ampacimon, Lindsey Systems, LineVision. NewGrid, Smart Wires and WindSim Power.

The group has been refining its *position* in response to FERC's March 2020 Notice of Proposed Rulemaking on Electric Transmission Incentives Policy under Section 219 of the Federal Power Act. (See *FERC Proposes Increased Tx Incentives*.)

The technologies can improve reliability and reduce congestion costs, Grid Strategies Vice President Jay Caspary said.

"We estimate that the deployment of grid-enhancing technologies across the U.S. would save about $2 billion in customer costs by being able to take advantage of more efficient, cleaner energy that currently is bottled up and constrained on the power system," Caspary said.

The proposal recommends benefits be calculated through production cost modeling and that projects have a minimum benefit-cost ratio of 4:1. For projects under $2.5 million, transmission owners would receive 25% of savings, with total incentive capped at $10 million. Larger projects would be subject to a competitive process and awarded based on the highest net customer benefit, considering both benefit-cost ratios and consumer's share of savings. Any qualified market participant could propose a project, and after three years, if the ratio remains greater than 4:1, the owner can reapply to extend the agreement for an additional three years.

### Aligning Incentives

The WATT proposal would align incentives for GETs investments with the public interest pursuant to the directive in the Federal Power Act, said Daniel Hall, central region director for electricity and transmission at the American Clean Power Association.

"It would incent utilities to invest in technology that benefits consumers by allowing their shareholders to share in those cost savings," said Hall, former chairman of the Missouri Public Service Commission. "This is a classic win-win-win — a win for consumers, a win for utility shareholders, and a win for the environment."

GETs are an important way to help expand line capacity at comparatively low cost compared to new transmission lines, and the cost savings multiply because GETs help bring low-cost renewables onto the grid, said Tyler Stoff, director of regulatory affairs at the American Council on Renewable Energy (ACORE).

The current market design "can't adequately motivate GET deployment because profit is directly proportional to capital invested, which for these technologies can be very small," Stoff said. "ACORE supports a specific, well-defined incentive focused on low-cost projects that provide quantifiable congestion reduction benefits, and I think we see that in the proposal laid out here today."

The Renewable Energy Buyers Alliance also supports GETs, Director of Policy Innovation Adrienne Mouton-Henderson said.

"As highlighted by this proposal, GETs can increase grid flexibility and reliability, especially during extreme weather events such as the wildfires of California and Hurricane Ida that has ravaged my home state of Louisiana and the Northeast," Mouton-Henderson said. "The time to act is now."

"In the Eastern [Interconnection] there's need for increased transmission capacity. But rather than build new lines, transmission owners are shifting costs to interconnection customers for new network upgrades," said Melissa Alfano, manager of regulatory affairs at the Solar Energy Industries Association.

"The results are these large, drawn-out fights at FERC over the cost of those upgrades … but these fights are all based on the underlying assumption that the transmission system is fixed in capacity and topology, which is an outdated idea," Alfano said. ■

## FERC/Federal News

# Storage the 'Linchpin' to 24/7 Carbon-free Power, Corporate Buyers Say

*By Rich Heidorn Jr.*

Google has purchased renewable energy equal to its total consumption every year since 2017, yet it's still a long way from its 2030 goal of using carbon-free energy in all locations and all hours.

Although Google currently purchases renewable energy equivalent to its load, there are hours when its contracted renewables produce more than its data centers and other facilities consume. Conversely, in the middle of the night, it must rely on nuclear- and fossil fuel-generated power when wind and solar production is lower than consumption.

Mike Della Penna, Google | *Google*

To overcome this "dissonance," says Mike Della Penna, Google's technical program manager for energy development, the company is pursuing improved wind forecasting, enhanced geothermal generation and policy changes to increase competition and eliminate barriers to corporate procurement.

But to get all the way there, the company and other large energy users say, they will need to greatly increase their use of storage.

"Wind and solar [are] great, but it will only get us so far," Della Penna said during a *webinar* sponsored by the Energy Storage Association on Thursday. "Hence the need for energy storage technologies."

### Corporate Buyers Seeking Storage

Priya Barua, Renewable Energy Buyers Alliance | *Renewable Energy Buyers Alliance*

Priya Barua, director of zero-carbon innovation for the *Renewable Energy Buyers Alliance* (REBA), said 2020 marked a change in the way companies are procuring renewables to ensure decarbonization. "While this change in procurement played out in many ways, the inclusion of storage in corporate procurement contracts was one that really jumped out," she said. "Since 2010, we've seen an 88% reduction in the cost of some storage technologies. And now a decade later, in 2020, five corporate companies announced transactions and included storage totaling nearly half a gigawatt."

In response to member interest, Barua said REBA will release a primer on using battery energy storage later this month that will include contracting best practices and examples of business use cases. REBA says its 240 members are responsible for 95% of the renewable energy transactions in the U.S.

Including all the units of Google parent Alphabet, the company's annual electricity consumption has quadrupled since 2012 to more than 12 TWh in 2019. In 2020, Della Penna said, Google reached 67% carbon-free energy globally on an hourly basis, with five of its 23 data centers operating 90% carbon-free around the clock.

Della Penna said Google believes it can meet its 2030 goal because of the declining costs of storage and renewables, government commitments to reduce electric-sector emissions, and increasingly sophisticated commercial offerings.

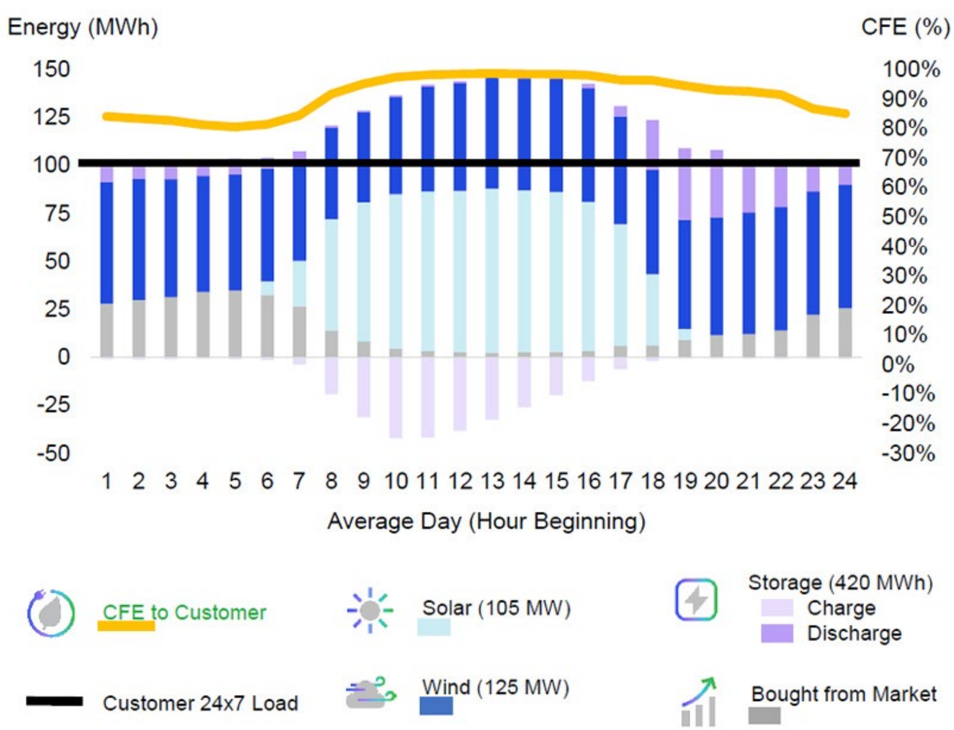
In May, Google and AES *announced* a 10-year, 500-MW supply contract that will provide Google's data centers in Virginia with 90% carbon-free electricity (CFE) from the PJM grid by 2024.

AES will use its own renewables and those of third-party developers to assemble the 500-MW portfolio, which it said will require about $600 million in investments. The plan envisions storing excess renewable energy during the hours of the strongest solar production and tapping the storage after the sun goes down.

Neeraj Bhat, AES Clean Energy | *AES*

Neeraj Bhat, chief product officer for AES Clean Energy, said AES sought to reduce complexity and market risk in soliciting bids from developers across PJM on Google's behalf.

"You can model 24/7 CFE in [Microsoft] Excel, and then when you go to the market and talk to real developers with real projects with real challenges, all those nice little assumptions start to really get tested," he said. "We ended up modeling north of 200 different portfolios [and] ended up [with] about 10 different assets to produce a load-shaped 90% carbon-free energy supply.




Under its 10-year supply deal with Google, AES envisions storing excess renewable energy during the hours of the strongest solar production and tapping it after the sun goes down. | *AES*

# FERC/Federal News

"The portfolio that we ended up putting together for Google did include some [run-of-river] hydro as well, which is great," he added. "Any time you can get a generation source with a different generation profile, that really adds to the CFE output." To reduce market risk, AES made trades for price hedges, allowing it to offer Google a fixed-price contract.

### Storage's 'Surgical Nature'

Bhat said the value of storage is its "surgical nature."

The PJM grid averages 30 to 40% carbon-free energy over a year, Bhat said. That increases to 65% CFE with a solar-only portfolio or 77% for a wind-only portfolio. Adding energy storage to wind and solar increases that to 91%, he said.

Adding wind to a portfolio can help fill evening hours with CFE, but it's inefficient. Bhat likens it to Jackson Pollock's method of painting. "You're really throwing a lot of megawatt-hours of paint at that canvas, and a lot goes to waste, because you're not getting exactly where you need to; you're not getting the pixels that you really need," he said. "The beauty of energy storage in this picture is that it becomes extremely surgical for taking exactly the hours that you need and pulling that out when you don't need them and putting them in exactly when you need them. And that's why we think the linchpin of a grid that is going to be 100% carbon-free is going to be storage."

Bhat said the carbon reductions provided by storage are not linear. "You really start to dig deeper into those very carbon-intensive hours. And so you get much more carbon reduction when you're really painting the full canvas rather than kind of cherry picking the solar hours, which, in most grids of the country, are becoming less and less carbon intensive."

### Dispatching for Carbon, not Cost

Reaching 24/7 CFE also requires "hourly load data aggregation: people understanding what their hourly profile is, understanding where they have load flexibility, and the carbon intensity of a particular grid and scenarios in which they can ramp down their own load, and especially carbon-intensive hours," Bhat said.

Dispatch algorithms must be maximized not for the price of energy, but for the carbon-free content of the supply. "Happily, there's a lot of correlations between those two," Bhat said. "It's not perfect, but it tends to serve in both directions if you're dispatching the storage facilities appropriately."

Another tool will be more granular renewable energy credits (RECs), he said. "Renewable energy credits today are effectively a monthly tool. There's not hourly granularity on when a particular renewable megawatt-hour was generated."

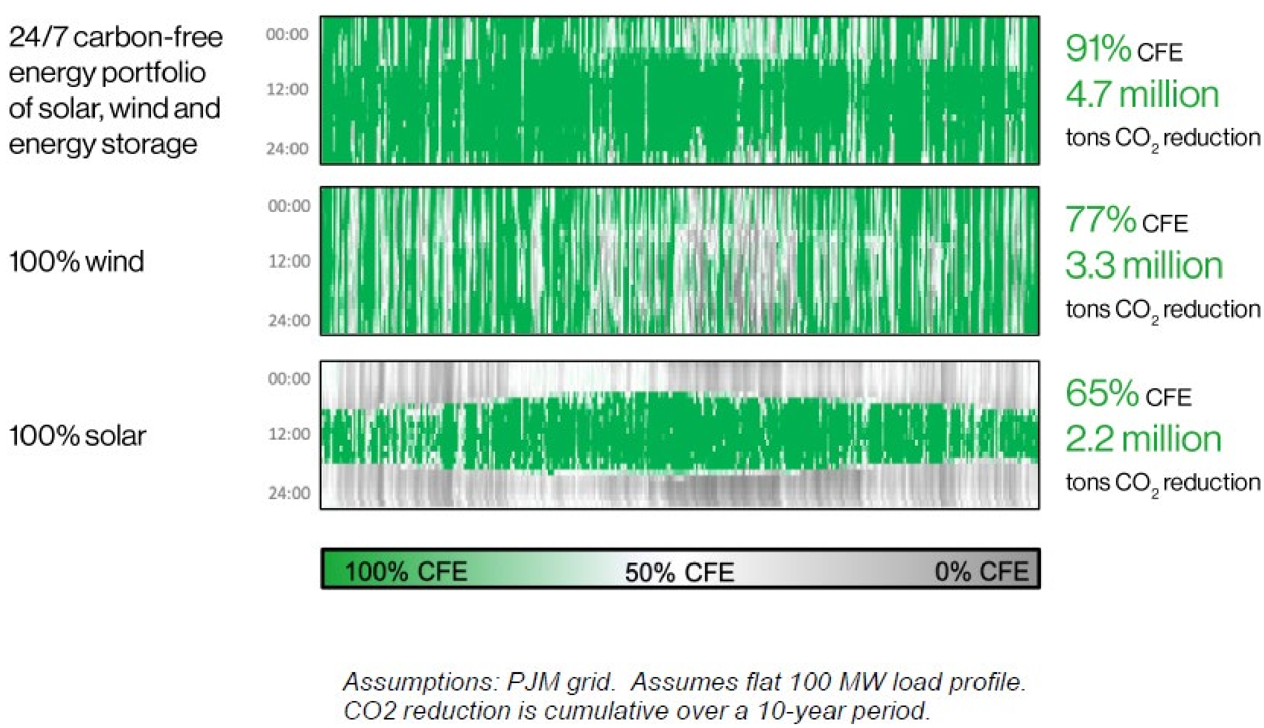
Tagging RECs by the hour of production allows companies seeking 24/7 CFE to value RECs differently based on when they were produced.

"So if a noon REC is worth $5 or $6[/MWh], maybe a REC [produced] at 8 p.m. is worth $12 or $15," Bhat explained. "And so all of a sudden, you're starting to create price signals and incentives for more storage to be deployed into the system."

Della Penna said not all the regions where Google operates data centers have the market structures that allow the deal it signed with AES for its Virginia facilities.

He said the company is seeking to use the Tennessee Valley Authority's "robust" corporate renewables procurement program "to solicit for new resources that can help us build up our carbon-free energy profile across the region."

"We're equally comfortable — although it's more work on our side — assembling the CFE portfolio ourselves ... and building up a book of resources and" power purchase agreements, he said. "That's precisely what we've done in SPP to date." ■




The PJM grid averages 30 to 40% carbon-free energy (CFE) over a year. That increases to 65% CFE with a solar-only portfolio or 77% for a wind-only portfolio. Adding energy storage to wind and solar increases that to 91% CFE.| *AES*

## FERC/Federal News

# DOE Study: Solar Could Provide 45% of US Power by 2050

## *Grid Decarbonization, Electrification Could Cut GHG Emissions 155%*

*By K Kaufmann*

If the U.S. is to decarbonize its electric grid by 2035, solar deployment will have expand at an unprecedented rate, from a cumulative capacity of 80 GW currently to between 760 and 1,000 GW by 2035, according to a report released Wednesday by the Department of Energy.

If electrification of transportation, buildings and other economic sectors is added, solar could be providing close to 45% of the nation's electricity demand by 2050, up from just 3% now.

At 310 pages, the *Solar Futures Study* drills into all aspects of what it is going to take to hit such ambitious numbers, which, it says, will be challenging but possible. Research to drive innovation and ongoing cost reductions; supply chain buildout, including recycling of critical materials; as well as grid expansion and new business models for wholesale and retail markets are all part of the roadmap.

Wholesale markets will have to "adapt to the increasingly dominant role of zero-marginal-cost renewable energy, and retail markets must adapt with rates that reflect the changing grid and an increased role for distributed energy resources," demand-side services and enhanced energy reliability, the report says.

For example, the study calls for "flexible and adaptive interconnection" strategies to promote cost-effective DER deployment. An approach called active network management "uses flexible interconnection agreements, sophisticated communication infrastructure and information on local power system conditions (forecasted load, constraints, etc.) to automatically adjust the behavior of DERs," the report says. "In exchange for allowing the utility limited control over the DER and accepting limited curtailment throughout the year, interconnecting customers endure shorter interconnection processes and avoid paying for prohibitively expensive distribution upgrades."

At the same time, the report says, with more solar, wind and storage online, the grid will become "increasingly reliant on weather-dependent, inverter-based resources (IBRs), representing a dramatic change from the current grid based primarily on synchronous electricity generators. A grid dominated by IBRs will require new approaches to maintain system reliability and exploit the ability of IBRs to respond quickly to system changes."

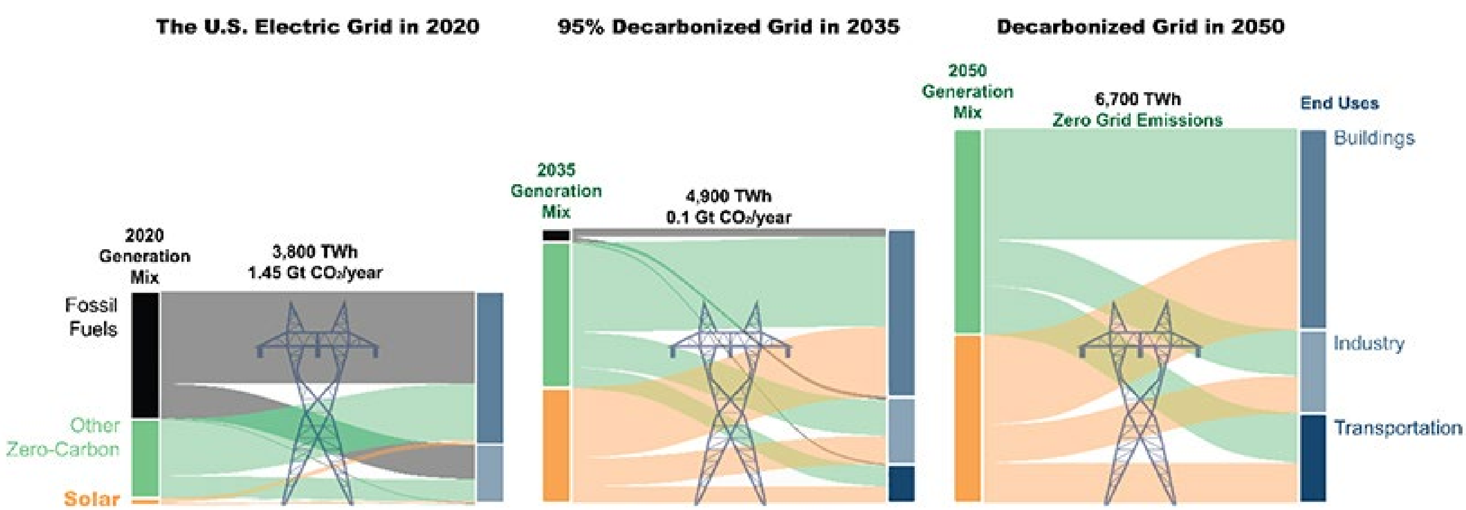
Clean, firm capacity will also be needed to fill the IBR gaps, the report says, specifically, 1,600 GW of energy storage with up to 12 hours of duration by 2050. "However, because solar and wind occasionally provide insufficient supply for several days, advances in technology that can provide clean, firm capacity at any time are needed to reliably meet demand as full decarbonization is approached."

Those advances may not come fast enough. Based on models and projections from the National Renewable Energy Laboratory, the study anticipates that a 95% decarbonized grid will be possible by 2035, but getting the last 5% could be too expensive if the goal is also to ensure no major increases in consumer electricity prices. Even with aggressive policies, a residual 5% of fossil fuel generation may still be in the mix at that point, the report says, though a 100% clean grid will be possible by 2050.

### Demand Grows, Emissions Drop

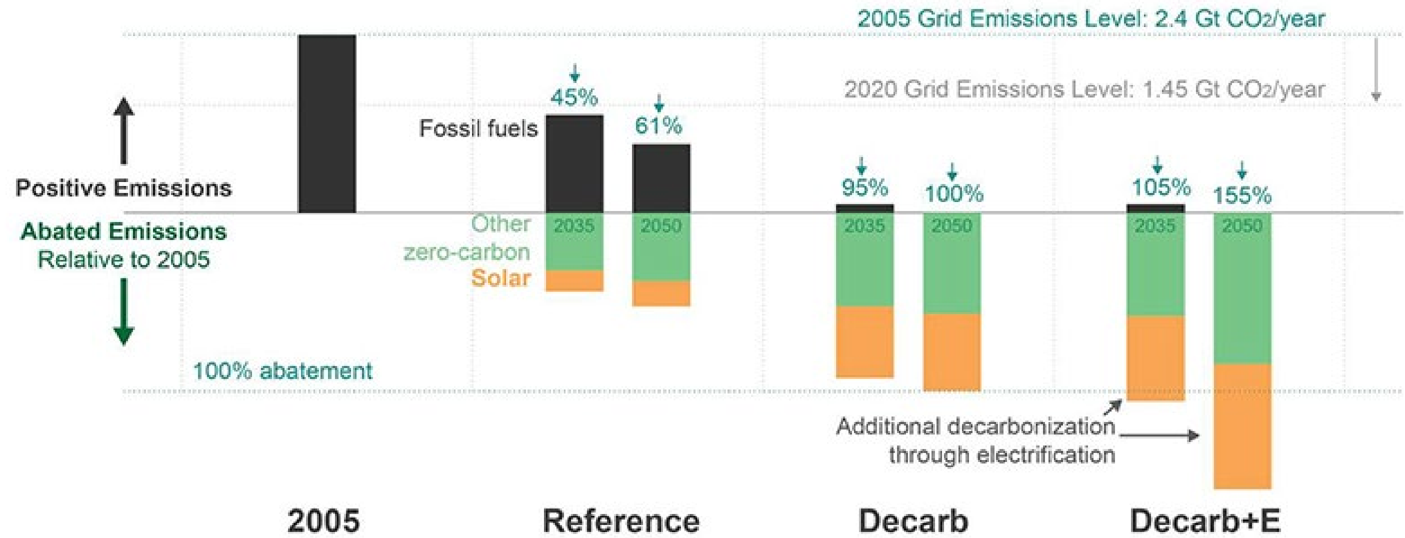
Heading into November's U.N. climate change conference in Glasgow, the report positions the U.S. solar industry as playing "a unique and central role" in emission reduction because of two key attributes of the technology, the report says. It is modular; that is, it is deployable at any scale, from a few kilowatts of rooftop panels to hundreds of megawatts spread over hundreds of acres of land.

It is also "diurnal," simultaneously variable and reliable, based on "daily and seasonal patterns of the rising and setting sun," the report says. Daily variability of cloud cover and other factors notwithstanding, this diurnal reliability "means that grid operations and electrici-




Grid mixes and energy flows in 2020, 2035 and 2050 under the Decarb+E scenario | *DOE*

# FERC/Federal News




Grid emissions and abated grid emissions by scenario in 2035 and 2050, relative to 2005 grid emissions | *NREL*

ty demand can be proactively managed to maximize use of low-cost, zero-carbon solar energy," the report says.

Even without President Biden's aggressive target for grid decarbonization, the study's business-as-usual scenario — based on market forces and existing federal, state and local policies — anticipates 380 GW of U.S. solar capacity in 2035 and 670 GW in 2050.

The bigger numbers are generated in a second "Decarb" scenario, which sees federal policy driving grid decarbonization and accelerated solar deployment by 2035, and a third, "Decarb+E" option, targeting economywide decarbonization via electrification of transportation, buildings and other sectors.

Other core findings in the study include:

- Electricity demand jumps 30% with a 95% decarbonized grid, from 3,800 TWh per year in 2020 to 4,900 TWh in 2035. Demand increases another 35% to 6,700 TWh in a net-zero 2050. At the same time, the Decarb+E scenario could make the U.S. carbon negative by 2035, with emissions dropping 155% from 2005 levels by 2050.
- Technological innovation could cut solar costs another 60% by 2030 "via improvements in photovoltaic efficiency [and] lifetime energy yield," which could in turn open up new applications for solar "in novel configurations associated with agriculture, waterbodies, buildings and other parts of the built environment."
- Getting to a 95% decarbonized grid by 2035 will increase system costs by $225 billion, or 10% more than business as usual, versus $562 billion, or 25% more for Decarb+E, the report says. "However, avoided climate damages and improved air quality more than offset those additional costs, resulting in net savings of $1.1 trillion in the Decarb scenario and $1.7 trillion in the Decarb+E scenario," the report says. ■

## FERC/Federal News

# Overheard at the USEA Advanced Energy Technology Forum

## *Forum Focuses on Opportunities and Challenges of an Integrated, Resilient Grid*

*By K Kaufmann*

The future of the U.S. energy system is integrated, which had multiple meanings and raised complicated questions for a range of speakers at the United States Energy Association's Advanced Energy Technology Forum on Thursday.

At Brookhaven National Laboratory in New York, the focus is on integrating thousands of megawatts of solar, offshore wind and energy storage onto the state's electric system, said James Misewich, the lab's associate director.

"What is the right energy storage technology? I don't think lithium-ion is actually going to be that scalable solution we're going to need," Misewich said during an opening panel discussing the new technologies being developed at his and other national laboratories.

"We're looking at other technologies — aqueous electrolyte storage capabilities, for example, that reduce fire hazards, and using more Earth-abundant materials, like zinc and manganese … There's a nexus of energy storage challenges and grid challenges that need to be addressed together. We want to answer this question with modeling before we try to answer it on the real electric grid," he said.

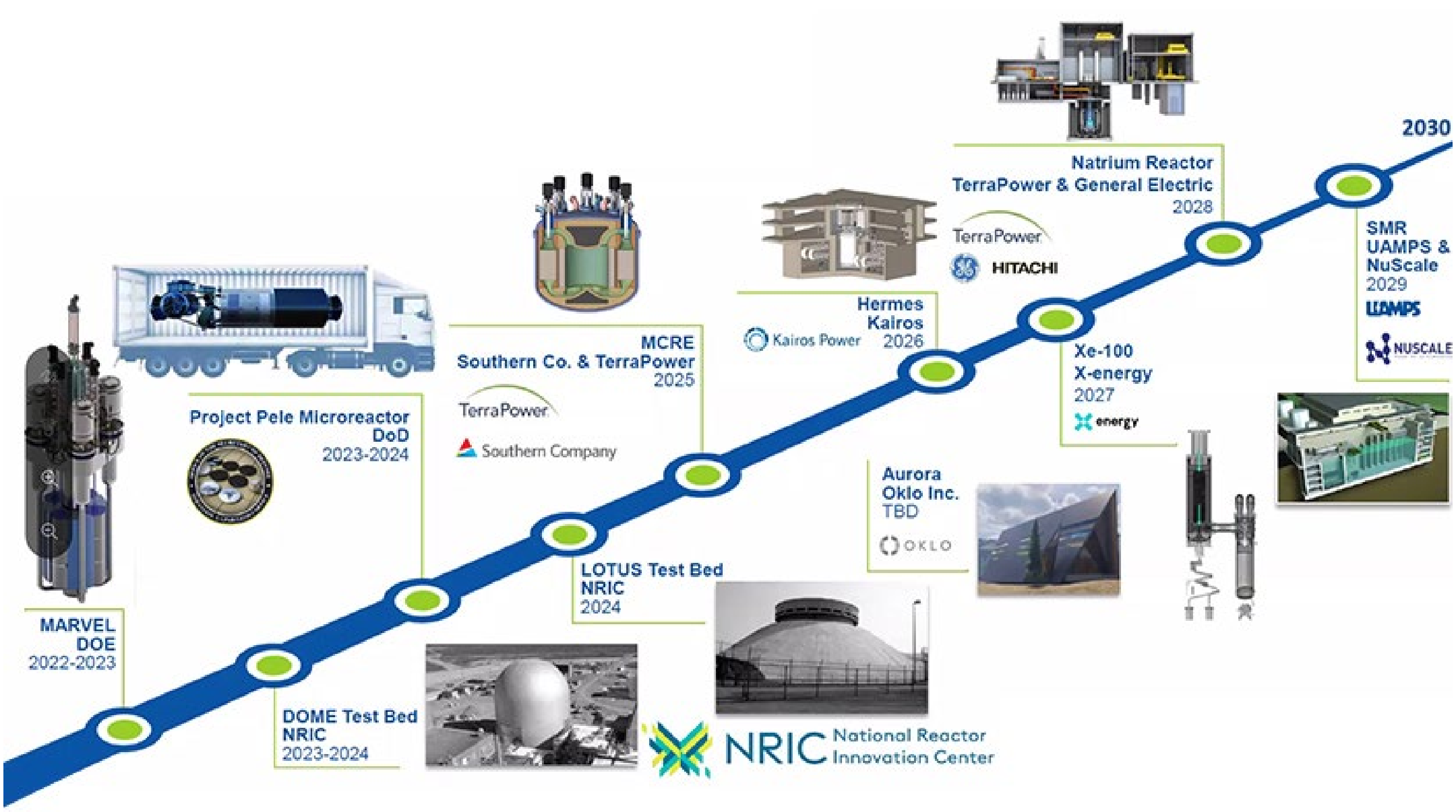
The half-day virtual forum provided a condensed, at-times provocative overview of the emerging technologies and policies that will be critical to rapid decarbonization of the U.S. grid, and the opportunities and challenges they pose for diverse stakeholders and regulators.

At FERC, Commissioner Allison Clements is looking at another critical nexus — in the Western states — on the need for integrated power systems that can "improve reliability, decrease cost for customers and ensure resilience in the face of disasters and extreme weather events.

FERC Commissioner Allison Clements | *USEA*

"I'm spending a lot of time listening to people in the West, trying to understand what a more coordinated, more integrated market looks like for them," Clements said during the forum's second panel on infrastructure challenges at the federal and state level.

FERC has "a lot of expertise to bring to the table under the Federal Power Act," she said. "We have concurrent jurisdiction with the states around a lot of these issues; so, things will not work in this rapidly changing environment if we're not kind of walking




The roadmap for accelerating advanced nuclear reactor demonstration and deployment, discussed at the USEA Advanced Energy Technology Forum | *Idaho National Laboratory*

# FERC/Federal News

together with the states on this path towards increased coordination."

## Unaffordable Resilience


NARUC President Paul Kjellander | *USEA*

Paul Kjellander, president of the National Association of Regulatory Utility Commissioners (NARUC), pointed to a new FERC joint task force on transmission that will provide federal and state regulators a forum to tackle cost and benefit allocation issues that can hamstring projects. NARUC recently nominated 10 state utility commissioners to the task force, which will have its first meeting at NARUC's annual meeting in November, Kjellander said.

But he also echoed many in the power industry on the challenges of siting and approving transmission projects, and the problems for utilities when projects get stalled. The key differentiator between transmission projects that get built and those that don't is whether they run through federal land subject to the intensive permitting process required under the National Environmental Protection Act (NEPA), he said.

The NEPA process can take years, he said, and by the time such projects get sited, utilities may have to "find other options to serve the load. You can't wait; you have to serve that load … and that makes that transmission line obsolete before you even break ground."

Speaking on the challenges of system resiliency and hardening in the face of extreme weather events and wildfires, Kjellander said the pain point for utilities and regulators is often cost. Utilities could certainly build systems that could power up quickly after a storm, but the cost of such a system could make electricity unaffordable, he said. The unprecedented nature of recent storms and fires also makes adequate system hardening extremely difficult, he said.

With complex issues coming at regulators left and right, NARUC is now "laser-focused" on regulator education, Kjellander said.

"People aren't aware of the harsh reality of being a regulator. The average tenure of a state commissioner is four years, and in many states, they don't get elected because of everything they know about the utility sector, they get elected because they're more popular than the person they ran against. … We've got to look at that — the need to educate regulators — to create the platform for them to get up to speed sooner, so they can be sharper and stronger in their role."

## Decarbonized, Distributed, Digitized


Mark Lauby, NERC | © *RTO Insider LLC*

Mark Lauby, senior vice president and chief engineer at NERC, also spoke about the challenges to grid safety and reliability in the face of unprecedented extreme weather events that are widespread, of long duration and not going away.

"We need to understand what the implications are and plan, design and operationally plan what I'm going to be doing the season ahead to deliver the energy and such reliability services," Lauby said. "And then also on a rolling, three-week basis, where am I going to get my energy from? These are the challenges being faced more and more."

As the energy system becomes increasingly decarbonized, distributed and digitized, he said, current resource adequacy measures may already not be sufficient.

"We have multiple states where actually the worst time may not necessarily be on peak, but maybe when you are doing maintenance on units and you have a sudden cold spell, and now all of sudden, all your energy gets sopped up," Lauby said. "What does that mean and how do we plan for that?"

Looking at the winter power outages in Texas, Lauby said, "This is the first time I'm aware, where load became a critical element to the reliable operation of our system. That is to say that we didn't serve that load; that load then could not serve us. So that interdependency is something we have to start recognizing and modeling.

"One of the questions will be where are the balancing resources really coming from?" he said. Utilities and grid operators will have to manage "the uncertainty of various mixes that we have as we translate this policy and economic [realities] into a resource mix, which is perhaps more sensitive to weather and certainly has a built-in uncertainty to fuel," he said.

Natural gas support will be needed until other technologies, like storage, hydrogen and small, modular nuclear reactors are available at commercial scale, he said. "Kind of like, in case of emergency, break this glass and move in."

## What Net Zero Means

For Marianne Walck, deputy lab director at the Idaho National Laboratory, an integrated system means developing applications for advanced, small and even transportable nuclear reactors to produce power and heat for industrial processes, clean hydrogen production and water desalinization. The lab is building its own microreactor — the Microreactor Applications Research Validation and EvaLuation (MARVEL) project — which Walck said could be online by 2023, with two microreactor test beds also being planned.

The goal for nuclear and low-carbon technologies such as carbon capture is to scale and bring down costs by expanding their uses beyond electricity production, said Jennifer Wilcox, DOE's principal deputy assistant secretary for fossil energy and carbon management.

The department's work on carbon capture has been mostly focused on coal, she said, but "we're leveraging that expertise" to examine capturing natural gas in the power sector while also looking at industrial sectors as well, specifically cement and steel.

"When you look at coupling these kinds of industries to carbon capture and reliable storage, you can provide low-carbon supply chains to help others meet their emissions reductions in terms of net-zero goals," Wilcox said.

Carbon capture goes to the heart of "what net zero means," she said, referring to the "committed emissions" that are already in the atmosphere or will be as a result of ongoing fossil fuel use.

"For every carbon dioxide molecule we put into the atmosphere, we have to be able to pull it back out, and that's net zero. That's the simple math," she said. "We have to deep-decarbonize in every sector and every chance we can … because if we don't do it, and we let those emissions go into the atmosphere, we're going have to pull them back out."

But scaling carbon capture technologies — such as the Orca direct-air capture plant opened on Wednesday in Iceland — should not be seen as a license to continue "burning fossil fuels 24/7," Wilcox said.

"Things like direct air capture should really be used very strategically in order to offset emissions that are hard to avoid, like the aviation sector as a whole and agriculture. One of the things we're trying to do in our office also is decoupling carbon dioxide removal from fossil [fuels] so that they're not conflated." ■

## Southeast

# TVA Sued Over Contributions to Trade Groups

*By Amanda Durish Cook*

A conservation group has sued the Tennessee Valley Authority over its contributions to trade associations and industry groups.

The Center for Biological Diversity (CBD), arguing those contributions are a misuse of ratepayer funds, said it's inappropriate for TVA to make payments worth millions to Edison Electric Institute, the Energy and Wildlife Action Coalition and other groups. The CBD characterized the two as "anti-environmental advocacy groups" and said TVA is violating First Amendment rights by forcing customers to fund the organizations when they only serve the utility's interest. It said ratepayer's unwitting contributions amount to political speech.

The lawsuit was filed Thursday in the Eastern District of Tennessee. The Southern Alliance for Clean Energy (SACE), Alabama Center for Sustainable Energy, Appalachian Voices, Solar United Neighbors, and Sowing Justice joined CBD in the filing.

The groups said EEI and the Energy and Wildlife Action Coalition "litigate and lobby to delay the critical transition to clean energy, hamper efforts to combat the climate emergency and deny protections to imperiled wildlife." Since 2015, TVA has paid annual dues of about $500,000 to EEI, which CBD said lobbies against decarbonization.

The conservation group also said TVA invoices reveal that dues to Utility Water Act Group, Utility Solid Waste Activities Group and the now-defunct Utility Air Regulatory Group (UARG) were partially billed for "influencing legislation." The utility-backed groups fund law firms that lobby against environmental legislation, though not explicitly on TVA's behalf.

TVA has paid about $7.3 million since 2001 to the UARG, which was dissolved in 2019. It also currently pays more than $100,000 annually for membership in the Utility Solid Waste Activities Group and has paid about $200,000 for services in 2018 to the Utility Water Act Group, which opposes Clean Water Act protections.

During a 2019 congressional probe of UARG by the House Energy and Commerce Committee, TVA CEO Jeff Lyash was asked to explain TVA's involvement with the group. He said UARG membership helped the agency

Cumberland Fossil Plant | *TVA*

"understand, plan for, and comply with highly technical and complex regulations" associated with the Clean Air Act.

But CBD said the disbanded group's sole function was to "undermine regulations designed to protect human health and the environment." It said TVA's membership violated its own environmental stewardship mandate.

CBD took exception to unspecified amounts paid to the Nuclear Energy Institute. TVA has not publicly released how much it contributes to NEI.

The lawsuit also seeks to compel TVA to respond to CBD's early 2020 petition outlining the same spending concerns. CBD said TVA has not addressed the petition beyond insisting its payments are appropriate.

"As the nation's largest public power provider and a federal agency, the Tennessee Valley Authority needs to demonstrate leadership by halting the financing of groups propping up the fossil fuel economy," Howard Crystal, legal director of CBD's Energy Justice program, said in a release. "Instead, it funds these groups to do its dirty work while it moves forward with building new fossil gas plants. TVA can and must do better."

The agency is facing mounting pressure to commit to a quicker decarbonization timeline than its current 2050 goal. (See *Green Groups Pressure TVA on Open Meetings, Decarbonization*.)

"TVA is unique in the power industry in that environmental stewardship and economic development are codified in the agency's founding mission," Maggie Shober, SACE' s director of utility reform, said. "It is imperative that the largest public power utility operate with accountability and transparency, stop funding anti-environment and anti-green jobs work, and invest in clean energy that will support the health of the Valley and the people who depend on it."

TVA spokesperson Ashton Davies said the organization had not been officially served with the lawsuit as of Friday.

"As a federal agency, TVA is prohibited from participating in lobbying activities, and the TVA Board has directed that any dues, membership fees, or financial contributions paid to external organizations not be used for purposes inconsistent with TVA's statutory mission or legal obligations," Davies said in a statement to *RTO Insider*. "Like other major utilities, TVA's membership in a diverse array of external organizations allows TVA access to specialized expertise and analysis that directly benefits all of our customers at a cost significantly lower than if TVA were to undertake such work alone."

CBD has a separate petition in front of FERC seeking to amend the commission's Uniform System of Accounts so that utilities' payments to trade and advocacy groups aren't recoverable from ratepayers. It says the change would compel utilities to "either demonstrate how funding these groups is in the public interest or provide this funding from shareholders rather than ratepayers." ■

## CAISO/West News

# DOE Orders CAISO Emergency Reliability Measures

### *Boosting Gas Generation Could Emit Pollutants Beyond Allowable Limits*

*By Hudson Sangree*

The U.S. Department of Energy approved CAISO's request last week for an emergency order allowing it to run natural gas plants that may exceed federal pollution limits as the ISO tries to maintain grid stability in the next two months.

"I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy and other causes, and that issuance of this order will meet the emergency and serve the public interest," Deputy Energy Secretary David Turk wrote in his *order*.

CAISO *applied* for the emergency order so that six generators, including aging power plants and new mobile units at existing facilities, can run free of emissions restrictions, starting this week, to provide up to 200 MW of additional supply.

"The CAISO respectfully requests that [Secretary of Energy Jennifer Granholm] issue the requested emergency order by Sept. 10, 2021, or a soon as possible thereafter, authorizing specific electric generating resources located within California to test and operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations," CAISO COO Mark Rothleder wrote to Granholm.

CAISO's cited reasons include high temperatures in the West, wildfires that threaten the bulk power system and "drought conditions [that] are greatly affecting the availability of hydroelectric power."

"Given these circumstances, state officials have identified a need to secure additional generating capacity to meet expected electricity demand and reserve requirements," Rothleder wrote.

Midway Sunset Cogen Plant | *Union of Concerned Scientists*

"Despite efforts undertaken by load serving entities and the CAISO to secure additional generating capacity, the CAISO continues to forecast potential supply deficiencies," he said. "For September, the CAISO continues to forecast a significant supply deficiency to meet planning reserve requirements during evening hours.

"Granting this request for an emergency order and authorizing the operation of additional generating capacity identified in this request when conditions merit is critical to the CAISO maintaining reliability and meeting its load obligations," he wrote.

### Use Only in a Level 2 Emergency

Two of the covered resources — Greenleaf Unit 1 in Sutter County and Roseville Energy Park in Placer County — are working with the state to deploy new generating capacity by mid-September, a crucial time in California when temperatures can rise while hydroelectric generation dwindles. The 30-MW mobile units are part of the California Department of Water Resources' efforts to add capacity.

"These covered resources will not have completed federal environmental permitting requirements by this date and will not operate unless they are subject to a DOE emergency order," CAISO said.

The mobile units "are not equipped with best available control technology to control emissions and have not completed permitting processes to obtain their operating permit under Title V of the Clean Air Act," the ISO said.

Four older units that could be covered by a DOE order are the Midway Sunset Cogeneration Facility Unit in Kern County, the Alamitos Energy Center in Long Beach, the Huntington Beach Energy Project in Orange County, and the Walnut Creek Energy Park in the city of Industry, near Los Angeles.

CAISO "understands that the electric generating units identified in this request have derated their facilities based on conditions set forth in their permits regarding nitrogen oxide emissions, heat output as well as fuel throughput," the request said. "Accordingly, the CAISO anticipates that the emergency order it is requesting may result in exceedance of National Ambient Air Quality Standards under the Clean Air Act."

The ISO said it intends to dispatch the units "at levels that exceed their permitted values" as on-call resources in its day-ahead timeframe if it issues a grid alert and will direct the units to operate only if it enters a Level 2 Energy Emergency Alert — "i.e. after the CAISO has initiated the dispatch of reliability demand response resources."

"In this case, these resources would operate outside of permitted levels only as needed to help mitigate the risks of a system emergency and avoid the need for the CAISO to curtail native load," Rothleder wrote. "In addition, the CAISO requests authority to dispatch the covered resources during transmission emergencies to reduce or eliminate the need to curtail native load to protect against the next contingency on the electric system."

The Alamitos and Huntington Beach plants are two of the four once-through cooling plants that the state decided to keep open for reliability despite their harm to sea life. (See *OTC Plants to Remain Open, Calif. Water Board Rules*.)

### Other Efforts

In April, FERC conditionally approved the Midway Sunset plant as the state's first systemwide reliability-must-run resource. The 248-MW plant, built in an oil field in the 1980s, was scheduled to retire this year. (See *CAISO's 1st System RMR Agreement Set for Hearing*.)

CAISO, the California Energy Commission and the California Public Utilities Commission have been working to obey Gov. Gavin Newsom's July 30 emergency proclamation by connecting resources that can meet projected energy shortfalls this year and next. (See *Calif. Governor Proclaims Emergency as Blackouts Loom*.)

In June, the CPUC ordered load-serving entities to deploy 11.5 GW of new resources to come online from 2023 to 2026, and, in July, CAISO took the rare step of using its capacity procurement mechanism to procure additional generating capacity. (See *CAISO Issues Urgent Call for More Summer Capacity*.)

The Energy Commission voted to issue emergency gas permits in August and on Wednesday approved procedures for expediting battery connections to the grid by next year. (See *CEC to Issue Emergency Gas Generation Permits* and *Calif. to Expedite Battery Licenses*.) ■

## CAISO/West News

# CAISO Sees 'Explosive' Growth in Storage in July

### *Latest Summer Market Performance Report Cites Problems, Fixes*

*By Hudson Sangree*

CAISO avoided blackouts in July despite dwindling hydropower and severe transmission problems while experiencing a surge in storage capacity meant to serve evening peak demand, the ISO said in the second of its new monthly summer market performance reports.

The July *report*, discussed in a stakeholder call Sept. 7, showed a sizable increase in battery storage compared with data from June.

The maximum *state of charge* on batteries connected to the CAISO grid increased from 3,000 MWh in June to 5,500 MWh in July because of additional storage on the system, the ISO said. July's total of 30 storage resources, mainly four-hour batteries, ranged in output from 4.4 to 920 MWh.

The maximum dispatch of those resources nearly doubled, going from 600 MW in June to 1,150 MW in July. Batteries tended to charge early in the day when solar was plentiful and discharge mainly between 7 p.m. and 9 p.m. to meet high evening demand during heat waves, a critical time for CAISO.

"We have seen through the summer the explosive addition of capacity coming from storage resources." Guillermo Bautista Alderete, CAISO's director of market analysis and forecasting, said on the stakeholder call. "Having that additional capacity is certainly good for meeting our expected demand."

On the downside, hydroelectric generation — typically a major in-state resource during the summer — was far below average for July because of an extended Western drought. (See *Western 'Megadrought' Curtails Hydropower* and *Western Drought Puts Hoover Dam Hydropower at Risk*.)

Storage in California's big reservoirs, such as Shasta Lake, dropped to 58% of average in July and generation capacity fell to 39% of average. Hydropower production was nearly 40% less than last July and 65% below the same month in 2019.

The shortfall can be attributed to the low amount of rain and snow that fell last winter, little of which made it into reservoirs, the U.S. Energy Information Administration *reported* in June.

Mountain snowpack was present at only three of 131 monitoring stations on June 1, EIA said. Snowpack usually provides water through summer as it melts, but high spring temperatures caused it to melt early, and the runoff "often didn't reach reservoirs … because it was absorbed by drought-parched soil and streams," it said.

CAISO's biggest crisis so far this summer happened on July 9, when the Bootleg Fire in southern Oregon burned under and around the Pacific AC Intertie (PACI), severely derating it. The PACI consists of three parallel 500-kV lines that deliver power from Columbia River hydroelectric dams to Northern California. (See *CAISO Declares Emergency as Fire Derates Major Tx Lines*.)

The Bonneville Power Administration derated the Oregon portion of the PACI from 4,450 MW to 428 MW by 7 p.m. on July 9. Around the same time, the southbound segment of the Pacific DC Intertie, which sends power from the Columbia River Basin to Southern California through Nevada, was derated to less than half its 3,100-MW capacity.

Amid high temperatures, CAISO's balancing authority area declared a Stage 2 energy emergency, "arming load and releasing operating reserves to meet energy needs," the July market performance report said.

The shortage of imported energy from the Northwest continued for days as the fire burned.

CAISO managed to get by without calling for rotating outages — as it was forced to under similar conditions on Aug. 14-15, 2020 — by issuing grid warnings, calling on demand response from industrial users and issuing flex alerts urging consumer conservation. Gov. Gavin Newsom declared an emergency, freeing up additional capacity.

"These challenging conditions were managed without the need to conduct rotating outages," the ISO's July report said. ■

# Calif. to Expedite Battery Licenses

### *Part of Effort to Deal with Potential 5,000-MW Shortfall Next Summer*

*By Hudson Sangree*

Acting on Gov. Gavin Newsom's emergency proclamation from July, the California Energy Commission approved a plan Wednesday by which batteries capable of providing at least two hours of discharge by the end of October 2022 can be licensed and connected to the grid in less time than it would normally take.

The move was the latest by state entities responding to Newsom's emergency proclamation, which said the state faces an energy shortfall of up to 3,500 MW this summer and up to 5,000 MW next summer. The governor ordered "all energy agencies [to] act immediately to achieve energy stability" and specifically instructed the CEC to expedite licenses for battery storage facilities of 20 MW or more that can meet evening net-peak demand. (See *Calif. Governor Proclaims Emergency as Blackouts Loom*.)

"The benefits of this *action* for Californians is that it helps immediately address climate change impacts and increase grid resiliency and reliability to help us avoid outages," CEC Deputy Director Shawn Pittard told commissioners in their monthly business meeting.

The CEC, California Public Utilities Commission and CAISO "are requested to work with the state's load-serving entities on accelerating plans for the construction, procurement and rapid deployment of new clean energy and storage projects to mitigate the risk of capacity shortages and increase the availability of carbon-free energy at all times of day," it said.

# CAISO/West News

The governor ordered a series of measures, some of which backtrack on the state's push toward clean air and energy. The closure of fossil fuel plants in the West without sufficient nonpolluting resources to replace lost capacity is contributing to the state's energy shortfalls. (See *CPUC Orders Additional 11.5 GW but No Gas*.)

The July 30 proclamation authorized the CEC to license gas-fired generators that can deliver energy this summer and fall during evening net-peak hours, after solar goes offline. The generators must meet criteria such as operating on a "previously disturbed site" with an existing grid connection.

In response, the CEC adopted new rules in mid-August allowing it to issue emergency licenses to gas-fired generators of 10 MW or more to help alleviate potential energy shortfalls this summer and beyond. (See *CEC to Issue Emergency Gas Generation Permits*.)

In his emergency *proclamation*, Newsom cited the ongoing effects of heat waves, drought and wildfires in the West.

"Because of drought conditions, water supplies in California's reservoirs have dropped to levels so low that hydroelectric power plants have had to reduce or cease production, leading to a reduction of nearly 1,000 MW of capacity and further exacerbating the drought's impact on California," he said. (See *Western 'Megadrought' Curtails Hydropower*.)

During a heat wave in July, the Bootleg Fire in southern Oregon derated the Pacific AC Intertie, "which delivers power from the Pacific Northwest to California, by almost 4,000 MW," it noted. (See *CAISO Declares Emergency as Fire Derates Major Tx Lines*.)

"Many other transmission lines are located in high fire threat areas, including lines located in other states on which California depends, and thus wildfires are likely to continue impacting California's energy supply unpredictably during this wildfire season," Newsom said. ■

| AES

# Western EIM Approves 'Sub-entity' Participation

By Hudson Sangree

The Western Energy Imbalance Market's Governing Body approved the admission of "sub-entity" participants Wednesday, allowing utilities within the balancing authority area of a main WEIM participant to schedule and settle loads and resources independently.

The decision, which fell under the Governing Body's primary approval authority in its shared authority with CAISO, was part of CAISO's efforts to bring Xcel Energy's Public Service Company of Colorado (PSCo) back to the WEIM.

In December 2019, PSCo said it would join the WEIM along with three utilities in its BAA — Black Hills Colorado Electric, Colorado Springs Utilities (CSU) and Platte River Power Authority — under a joint-dispatch agreement.

But in June, PSCo announced it was putting its WEIM plans on hold after CSU decided instead to join SPP's Western Energy Imbalance Service (WEIS), with the intention of becoming a full RTO member. (See *Xcel Delays Joining EIM to Examine Options*.)

CAISO has been working with PSCo to convince it, along with Black Hills and Platte River, to join the WEIM.

Establishing sub-entity scheduling coordinators could bolster that effort, CAISO Vice President of Market Policy and Performance Anna McKenna wrote in her *memo* to the WEIM Governing Body.

"In addition to being applicable throughout the EIM, the EIM sub-entity category is an important provision for implementing the Public Service of Colorado balancing authority area into the EIM," McKenna said. "The proposal allows PSCo to preserve the existing commercial arrangements that most of the various utilities in its balancing authority area operate under."

CAISO's plan to allow sub-entities "to settle load imbalances directly with the ISO" defines a load zone for each sub-entity. The EIM sub-entities would then submit base schedules for their load directly to the ISO, McKenna wrote.

"Base schedules are the load and supply schedules that reflect EIM participants' planned operation and are used as the baseline against which imbalance energy is settled in the EIM," she explained.

"The ISO will model each sub-entity's load in the market as a customized distributed load aggregation point," McKenna said. "This will enable the ISO to use existing practices to settle directly with the sub-entity."

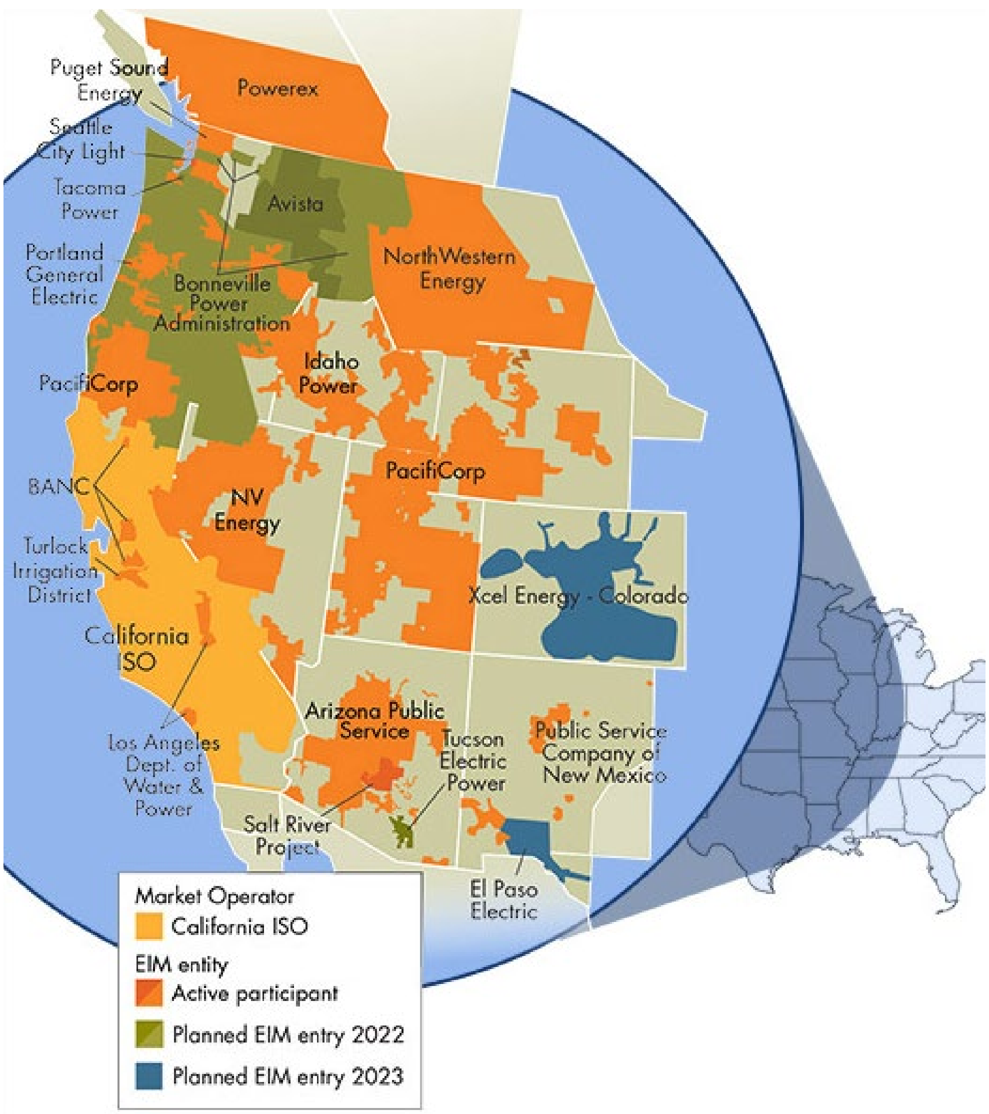
CAISO management proposed, and the Governing Body agreed, that the EIM sub-entities should be limited to those that are electric utilities embedded within an EIM entity balancing authority area that "do not receive long-term wholesale full requirements services from the EIM Entity."

Eligible sub-entities must own distribution or transmission lines directly connected to the transmission system of the EIM entity "for the purpose of providing regulated electric service to eligible retail or wholesale customers." They can also be a public utility that owns customer-serving resources, the CAISO plan said.

"Establishment as an EIM sub-entity is subject to the approval of the EIM entity that operates the balancing authority area in which the potential sub-entity is located," McKenna wrote.

Stakeholders generally supported the plan, though some voiced concerns about introducing complications and confusion into the WEIM's real-time interstate trading market.

The five members of the Governing Body unanimously endorsed the proposal. ■




The WEIM map used to include Xcel Energy's Colorado footprint | *CAISO*

# FERC Investigating Avangrid-NextEra Dispute over NECEC Interconnection

*By Jason York*

FERC on Sept. 7 ordered Avangrid and NextEra Energy to submit additional briefs in their ongoing dispute over the New England Clean Energy Connect (NECEC) transmission line project, which would bring 1,200 MW of Canadian hydropower through Maine to Massachusetts (*EL21-6, EL21-94*).

The commission also opened a proceeding to determine if specific provisions of ISO-NE's tariff are unjust and unreasonable in relation to the RTO's classification of a circuit breaker at NextEra's Seabrook Nuclear Station in New Hampshire.

A rendering of what the poles will look like along the 145-mile NECEC transmission line | *Central Maine Power*

Avangrid alleges that NextEra "is attempting to block, delay or add unreasonable costs to the interconnection" of the NECEC project and argues that the ISO-NE tariff requires Seabrook to accommodate the project's interconnection and "act in good faith" by upgrading a circuit breaker. Avangrid contends that NextEra has made it clear that it will not replace the breaker unless ordered to do so by FERC.

NextEra argues that Avangrid assumes that the Seabrook breaker is a transmission facility when in fact it is part of the generating facility. The breaker does not transmit energy and therefore not under the ISO-NE tariff provisions cited by Avangrid, which apply to network upgrades, NextEra says.

ISO-NE did not formally intervene in the proceeding but submitted a letter to the commission urging "expeditious" action to resolve the matter. FERC, in turn, wants the RTO to submit briefs on whether Seabrook's breaker is correctly identified as a part of a generating facility.

## Danly Dissents

Republican Commissioner James Danly dissented, saying that while his fellow commissioners cite the development of transmission projects as a priority, they have allowed this matter "to languish for nearly a year and have yet to issue an order on the merits."

Danly said such a delay is "unacceptable."

"Instead, the commission has waited four more months until today, 11 months after NextEra Seabrook filed its petition, to issue this order," Danly wrote. "And even now, the commission is not ruling on either NextEra Seabrook's petition or Avangrid's complaint."

Danly said the additional briefings to address whether NextEra Seabrook is obligated to complete the upgrade at its own expense under the terms of its interconnection agreement with ISO-NE, which was not previously raised, is not justified.

"The commission invites briefing on matters that it should be able to resolve wholly on the basis of the agreements between the parties, the ISO-NE tariff and commission precedent," Danly said. The additional briefings have "all but guaranteed that the generation breaker upgrades will be delayed for at least a year and a half." ■

## ISO-NE News

# Stakeholders Still Seeking Transparency from ISO-NE, NEPOOL

*By Jason York*

Speaking on a panel at the quarterly meeting of ISO-NE's Consumer Liaison Group on Thursday, the always outspoken Tyson Slocum, director of Public Citizen's energy and climate program, did not mince words.

For more than 20 years, ISO-NE and NEPOOL have "essentially privatized public policymaking as private entities" through their respective administrations of the New England electric grid and stakeholder process, Slocum said. "There is inadequate transparency and accountability in these institutions that don't reflect the public interest nature of what they're doing."

The Consumer Liaison Group holds open public forums to help regional consumers understand what is happening at the RTO. Slocum told it that "sweeping" reforms are needed to improve transparency and accountability. Neither ISO-NE Board of Directors nor NEPOOL stakeholder meetings are open to the public.

Opening NEPOOL stakeholder meetings to the interested public, plus recording and transcribing them, would be a start. It should be followed by a responsive ISO-NE board and reorientation of the NEPOOL voting sectors to make it less than "totally utility centric." Currently, stakeholders are broken into six weighted sectors: Generation, Transmission, Supplier, Alternative Resources, Publicly Owned Entity and End User.

"This has no realistic application to all of the people that are actually impacted by our electricity system," Slocum said.

Echoing Slocum's call for changes, Jolette Westbrook, director and senior attorney for energy markets and regulation at the Environmental Defense Fund, said there is one significant barrier for most people needed to be eliminated: the cost of participation. NEPOOL membership fees range from $500 for End Users to $5,000 for Generation, Transmission and Supplier members.

"I'm sorry, we just have to realize that what one entity can afford may not be affordable to others," Westbrook said.

Rebecca Tepper, chief of the Energy and Telecommunications Division in the Massachusetts Attorney General's Office, said that although ISO-NE's budget comes from collecting fees from market participants and ratepayers, "nobody seems to question the fact that we're spending millions of dollars to have the utilities participate in these proceedings and customers pay for that."

Tepper noted that governance of ISO-NE was one of the areas that the New England States Committee on Electricity identified in its *vision statement* in October 2020. In the *follow-up report* to the region's governors in June, NESCOE noted that the agendas of ISO-NE board meetings "indicate governance and transparency discussion; however, no process has been convened or proposal advanced" with the states.

"One of the three things that the states had requested is the one that has not made much progress, or at least not to the outside world," Tepper said. "I think it would be good to see that move forward and have some real dialogue about how the governance process can be more accommodating to people."

Slocum said that a multistate RTO like ISO-NE faces different governance challenges than single-state grid operators, like CAISO and NYISO. Still, there are lessons to learn, especially with appointments to the board. CAISO had a similar board structure to ISO-NE until the Western energy crisis spurred the California State Legislature to give the governor power to appoint or remove CAISO board members.

"It's a little more challenging to replicate that in New England, but it's important to state that [CAISO] is seen as an active partner with the state's ambitious climate and clean energy goals," Slocum said.

There is often conflict between New England states' policy goals and ISO-NE. Slocum said the way to align them is to have a board that is "directly accountable to either the states or to the communities within [the RTO's] footprint."

"This theoretical model that the ISOs came up with in the late '90s to have a dispassionate board that is supposed to be directly responsive to the needs of folks within the ISO footprint has failed," Slocum said. "We need to have a different governance structure that has direct lines of accountability because that failure and lack of accountability is what's driving most of the problems." ■

# Experts Call for Tx Reinforcements, Microgrids in Gulf System After Ida

*By Amanda Durish Cook, Holden Mann and Rich Heidorn Jr.*

Experts say the electric grid along the Gulf of Mexico needs sturdier construction, new technology and microgrids to avoid lengthy outages from increasingly common severe weather events.

The mass outages in Louisiana following Hurricane Ida inspired a replay of the outrage following February's winter storms that plunged millions of Texans into darkness for days. Even in the earliest stages of the disaster, leaders in New Orleans — where the entire city lost power after the storm cut all eight transmission corridors — had begun to question why Entergy seemed so unprepared for the disaster. (See *Entergy Investigations Certain to Follow Hurricane Ida Restoration*.)

For Mohammad Shahidehpour, director of the Illinois Institute of Technology's (IIT) Center for Electricity Innovation, the latest disaster is another in a growing list of wakeup calls unheeded by regulators and policymakers. In an op-ed published in *The Hill* on Aug. 31, he said February's crisis "wasn't just a failure of infrastructure, it was a failure of infrastructure planning."

Entergy crews work to restore power in New Orleans. The utility said Sept. 6 that more than half of the 902,000 customers who lost power in Louisiana following Hurricane Ida had been restored. | *Entergy*

"We worried about Texas, but now that it's over I don't think [policy makers] look back to say, 'How are we going to prevent the next one?'" Shahidehpour told *RTO Insider*. "Same thing here — what's happening in Louisiana is not the first time we have witnessed an extreme weather event in that region, and [I am skeptical] whether the local decision makers will do some substantial strengthening to make sure that [the next one] does not damage the system the way this one did."

## Microgrids to Mitigate Disaster

Shahidehpour said utility planners, regulators and political leaders should engage in a rethink of the North American electric grid.

He said microgrids, each handling a fraction of load, could lessen dependence on long, vulnerable transmission lines and make the grid less exposed to breakdown if generators go offline in a storm. Local microgrid controllers, operating independently, can pick up slack when one generator fails, in a scenario that Shahidehpour likened to a formation of planes.

"In a fleet of aircraft, each pilot can decide [what to do] in case of emergency … the head pilot sitting in the first aircraft is not going to be controlling [them] all," Shahidehpour said. "We need to do the same thing for our grid [and] come up with individual pilots to decide what's important in case of an emergency … and what they need to do to save their craft. … Right now, that's not the case: they've got 20 aircraft and often one pilot for the entire fleet."

Shahidehpour acknowledged that it would be difficult for a microgrid fleet to handle New Orleans' peak 1.2-GW load — though he said the existing grid may also be unsuited to keep pace with the ongoing electrification of society.

"We need to teach people that electricity doesn't have to be consumed all at once," Shahidehpour said. "If you're in a high-rise, and there are, let's say, 100 apartments, they all do not have to charge their phones or run their dishwashers at the same time. Yes, they all want to get it done by the morning, but you can set up a system where one is done at 2, one is done at 3, and one is done at 2:30 — all done [by] the time the customers want and [dispersing] the load to the extent that you don't have to make the existing utility system bigger and bigger."

Volunteer group *Footprint Project* brought mobile solar units to shelters in rural southern Louisiana to supplant gas generators. The group hopes the sight of solar panels powering recovery efforts will inspire communities to build back greener and closer.

## Beefier Tx Facilities

Hurricane Ida laid bare a need for utilities to be more realistic about the lifespans of their existing transmission in a changing climate, others argue.

Portland, Ore.-based energy consultant Robert McCullough said it's no longer sensible for utilities along the Gulf Coast to assume a 30-year lifespan for transmission facilities "given the high probability that the next Category 4 hurricanes will destroy even more equipment built to the previous engineering standard." He said today's equipment has been built to outdated safety standards and Entergy "overstates" the lifetime of its transmission and distribution equipment.

McCullough noted that four hurricanes have struck the Gulf Coast in the past year. He estimated that Ida destroyed 8.2% of Entergy New Orleans' almost $20 billion transmission and distribution assets.

# MISO News

Hurricane Ida destroyed more than 30,000 poles in Entergy territory, compared to Katrina's about 17,000, according to the utility. Combined with the 2020 destruction from hurricanes Laura (more than 14,000 poles) and Zeta (about 2,000 poles), 2020 and 2021 contain the most dramatic spike in grid devastation from hurricanes.

Entergy Louisiana is seeking permission from the Louisiana Public Service Commission to *recover* nearly $1.6 billion from ratepayers for Hurricane Laura, $215 million for Hurricane Delta and $177 million for Hurricane Zeta. The storms' succession was so rapid that Entergy combined the three requests for recovery along with February winter storm-related costs.

"Many utilities wait until older equipment is destroyed rather than preemptively replacing equipment. There are understandable regulatory reasons for doing so: it is easier to recover the cost of storm damage than it is to argue for early retirement of existing assets," McCullough said in a memo to clients. "Colloquially, it is often better to ask forgiveness than to seek permission, but this does not produce optimal results for either the utility or its customers."

McCullough said utilities should "break the cycle of seeking after-the-fact regulatory approval for storm damage" and "adopt depreciation schedules that reflect a more accurate estimate of the life of transmission and distribution equipment subjected to extreme storm weather."

He said a practice of replacement before failure will save "tremendous social cost."

"Hurricane Ida demonstrates once again that the cost of a prolonged outage eventually will dwarf the actual replacement expense of poles and conductors," he said.

Entergy said its new transmission *projects* are constructed to withstand winds up to 150 mph. But the utility has repeatedly declined to specify the age of the eight New Orleans lines that failed during the storm. On Sept. 3, it detonated cables from the collapsed and rusted transmission tower in Harahan, La., to clear the Mississippi River.

Construction firm Burns and McDonnell has been forced to halt upgrade work *twice* on Entergy's 16-mile, 230-kV Waterford-to-Vacherie line because of Hurricane Laura and Hurricane Ida. The line will carry power from the nearby Waterford 3 nuclear unit, which was *offline* for several days following the hurricane.

Entergy spokesman Neal Kirby said the company had no immediate response to the McCullough report.

"With regard to grid planning and hardening practices, Entergy's infrastructure hardening and resiliency investments help protect the electrical system from destructive weather and are developed to provide the best value to customers. Since the beginning of 2016, Entergy has completed $12.6 billion in transmission and distribution construction and other investments and will continue to make significant investments to continually repair and enhance the company's infrastructure," Kirby said. "We have spent approximately $1 billion systemwide in recent years upgrading plants and substations to new hardening standards following hurricanes. While ensuring the resilience of our infrastructure has always been a primary focus, we recognize that we must accelerate our efforts in light of increasingly frequent and severe weather events. We will continue to refine our understanding of where the specific risks attributable to climate change are expected to become more severe in the years and decades ahead and focus our hardening efforts accordingly."

S.R. Crown Hall at the Illinois Institute of Technology's Chicago campus, which has been operating as an independent microgrid since 2008 | *Arturo Duarte Jr., CC BY-SA 3.0, via Wikimedia Commons*

## Tech Assists

Adrienne Mouton-Henderson, deputy director of policy innovation for the Renewable Energy Buyer's Alliance, said resilience also would benefit from grid enhancing technologies (GETs), such as advanced power flow control, dynamic line ratings and topology optimization.

"GETs can increase grid flexibility and reliability, especially during extreme weather events, such as the wildfires in California, and Hurricane Ida," she said at a press briefing Wednesday, in advance of a FERC technical conference Friday on using shared savings to encourage utilities to deploy such technology.

Hudson Gilmer, CEO of LineVision, which sells overhead line monitoring technologies, said GETs are no replacement for hardening of assets, such as moving from steel poles to concrete and improving wind tolerance. Florida Power & Light reported that its recovery from Hurricane Irma in 2017 was four times faster than it was following Hurricane Wilma in 2005, thanks to $3 billion in grid-hardening investments. (See *Power Restored for 97% of Customers in Irma's Wake*.)

But Gilmer said GETs "individually and collectively result in a much more resilient grid."

"They can allow grid operators to route around outages much more flexibly and quickly. They can increase capacity on existing lines, and they can actually redirect flow," he said during the briefing, sponsored by the *WATT Coalition*. "[That] is absolutely part of the solution to increasing resiliency and also monitoring to understand the condition and detect anomalies that might be able to be addressed before severe weather rolls in." ■

# MISO News

## MISO Stakeholders Vote on Seasonal Capacity Auction Delay

*By Amanda Durish Cook*

The coal-fired Columbia Energy Center in Wisconsin will be retired by the end of 2024. | *Alliant Energy*

Stakeholders continue to criticize MISO's proposal to create seasonal capacity auctions and resource accreditation, saying it is too hasty and not rationalized, and warn they may pursue a more formal channel to vent their frustrations.

Those participating in MISO's Resource Adequacy Subcommittee might soon memorialize complaints with a formal stakeholder vote. They're currently completing email ballots on a *motion* to delay resource adequacy changes by a year until the 2024/25 planning year and to extend debate until at least the second quarter of 2022.

The MISO Coalition of Utilities with the Obligation to Serve introduced the measure during the RASC's meeting Sept. 1. MISO considers stakeholder votes as advisory in nature.

The motion also asks the grid operator to augment its proposal with three add-ons:

- a "transparent" and "robust" analysis to justify major changes to the resource adequacy construct;
- histograms and calculations of seasonal long- and short-capacity positions by local resource zone so that members can estimate the seasonal framework's impacts on their fleets; and
- a way for the RTO to "recognize prudently planned outages' contribution to resource adequacy."

"Prudently planned outages actually increase reliability," Big Rivers Electric's Marlene Parsley said during the RASC meeting.

Parsley also said MISO was tweaking the filing at the "11th hour" and said its proposal "continues to evolve late in the stakeholder process."

The grid operator has said it will file a proposal before October with FERC to create four independent seasonal auctions with distinct reserve margin requirements and a tougher seasonal capacity accreditation. The proposal will focus on a unit's availability over the past three years during the riskiest 3% of hours in a season to develop individual accreditation values for planning resources. MISO defines risky hours as those with either a maximum generation event or tight margin hours. (See *Discord Persists over MISO Seasonal Capacity Accreditation*.)

MISO said the changes are necessary to reverse a trend of shrinking reserves and a spate of maximum generation emergencies since 2016.

But the utilities group said, "MISO is seeking to fundamentally re-engineer nearly every aspect of its resource adequacy construct in a way that no other U.S. RTO has ever undertaken."

It also said the RTO should prove that its "quasi-random set of tight margin hours has any predictive correlation with future performance during a different quasi-random set of tight margin hours." Stakeholders have said MISO basing accreditation on unit availability during preselected risky hours throughout a season makes accreditation a volatile and hard-to-predict process.

Customized Energy Solutions' Ted Kuhn said MISO effectively ignored stakeholders' request to first try seasonal capacity auctions before tinkering with capacity accreditation values.

"Stakeholders are finding they have a proposal in front of them that's half-baked," he said.

Madison Gas and Electric's Megan Wisersky said the grid operator's current proposal was "incoherent" and agreed MISO would be better served with a staged approach.

During a Wednesday workshop, some stakeholders said the proposal appeared to still be in the design phase, rather than a finalized plan days from being filed at FERC.

Stakeholders questioned the seasonal outage rules that limit outages to a cumulative 30 days in a season before resources must replace the capacity they've signed up to provide.

Some said the limit in duration might encourage some unit owners to take shorter planned outages every year instead of risking replacement capacity requirements during more comprehensive maintenance outages once every two or three years.

"I think MISO needs to think more seriously about this," Kuhn said.

MISO staff promised that its outage coordinators will monitor patterns across units in outage behavior and propose new rules as necessary. ■

## MISO News

# Report: Renewable Developers Footing Tx Upgrade Bills

### *ICF: Projects' Upgrade Costs Present Hurdle to Wind, Solar*

*By Tom Kleckner*

Developers of new wind and solar projects in MISO's and SPP's generator interconnection queues are being asked to foot nearly the entire bill when connecting to the grid, while the entire system typically benefits from significant transmission upgrades, according to an ICF Resources *report* released Thursday by the American Council on Renewable Energy.

ICF, a global consulting services company, said its modeling of recent network upgrades assigned to the RTOs' new wind and solar projects found that many of these upgrades, if built, would deliver significant benefits to the grid. "The cost allocation fails to consider potential regional economic benefits from these network upgrades," the authors wrote.

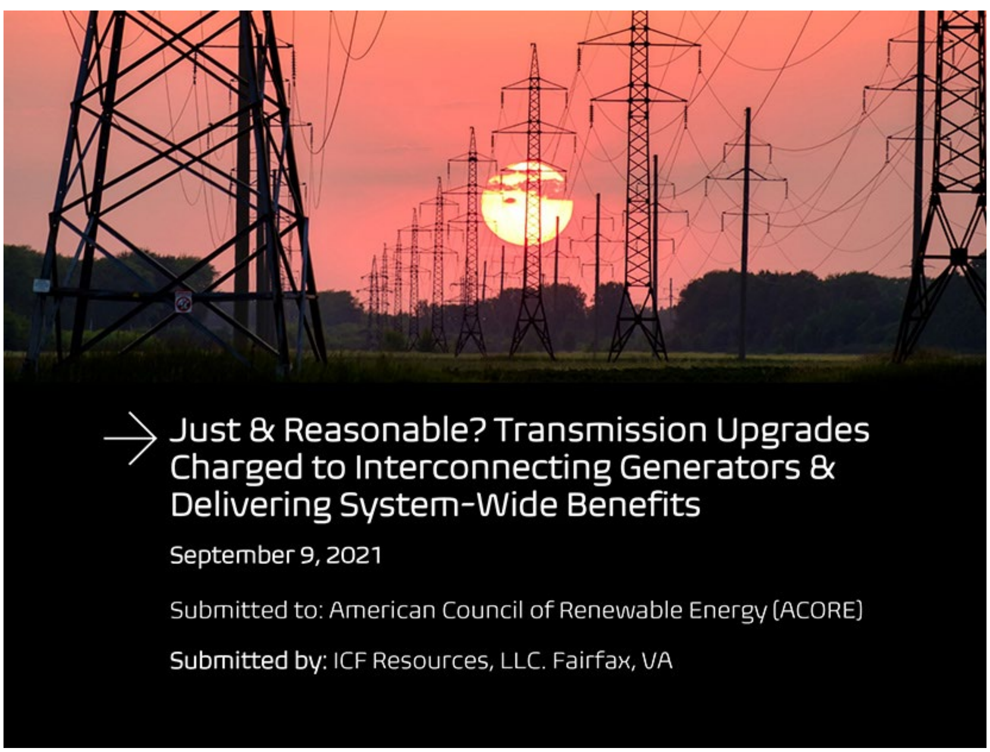
"This report confirms what many people have long believed: that network upgrades required of interconnecting generators often provide broader system benefits, even though the cost of the upgrades falls on the developers," former FERC Chair Norman Bay, now a partner with Willkie Farr & Gallagher, said during a press event Thursday organized by ACORE.

The report, "Just and Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits," says the RTOs' most recent system impact studies show network upgrade costs in the range of $270 (MISO South) to $448/kW (SPP).

MISO's most recent definitive planning phase (DPP) study for its generator interconnection queue found nearly $2.5 billion worth of upgrades were needed to interconnect 9.2 GW of generation in MISO South, according to ICF. Similarly, SPP's most recent definitive interconnection system impact study (DISIS) identified more than $4.6 billion worth of network upgrades to help interconnect 10.4 GW of generation.

"Given the over-subscribed power grid, interconnection customers are being allocated the full cost of adding new lanes to the highway and are increasingly responsible for building new highways," the authors wrote.

Under current cost allocation rules, project developers in both regions are responsible for paying for nearly all the upgrades' costs, potentially violating the "beneficiary pays" principle and the Federal Power Act's "just and reasonable" requirements. Under FERC's "beneficiary pays" principle, RTOs are required to ensure that transmission costs are assigned at least "roughly commensurate with estimated benefits."




A recent report prepared by the American Council on Renewable Energy finds renewable projects are footing much of the bill for transmission network upgrades. | *ACORE*

The costs are assigned directly to generators in SPP. In MISO, generators are responsible for 90% of the cost for upgrades 345 kV and higher, with 10% allocated regionally. Those below the threshold pay 100%.

Matt Pawlowski, NextEra Energy | *SPP*

"At the end of the day, our customers are bearing the costs of the projects that we're selling to them," Matt Pawlowski, NextEra Energy's executive director of business management and regulatory affairs, said Thursday. "If a significant amount of the upgrade costs is borne on us, we're passing those on to the customer. Whether it's a corporation or the ultimate end user of a utility, the ratepayers end up paying for that."

Pawlowski and Caroline Golin, head of energy markets and policy for Google, both called for a change in RTOs' planning practices, saying they no longer match a system that is flush with renewable energy projects.

"I think we're being foolish if we don't recognize we need to massively overhaul our transmission planning system. That starts with a general recognition that we are throwing money out the door by not doing that, and we are harming our community and the [renewable] industry," Golin said.

Renewable generation interconnection requests have risen exponentially in both MISO and SPP as wind and solar energy prices have continued to decline and states and corporate buyers seek to meet their renewable standards and goals. MISO and SPP have more than 150 GW of active solar, wind and hybrid resources stuck in their interconnection queues across both markets. At the time of the study, 92% of the 79 GW of requests in MISO's queue and 95% of the 103 GW of requests in SPP's queue were from those resources.

# MISO News

FERC is considering whether to re-evaluate how grid operators allocate costs for new projects seeking to connect to the grid. In July, the commission opened an Advanced Notice of Proposed Rulemaking (*RM21-17*) to reconsider its transmission planning, cost allocation and interconnection rules. (See *FERC Goes Back to the Drawing Board on Tx Planning, Cost Allocation*.)

Bay called the ANOPR "timely."

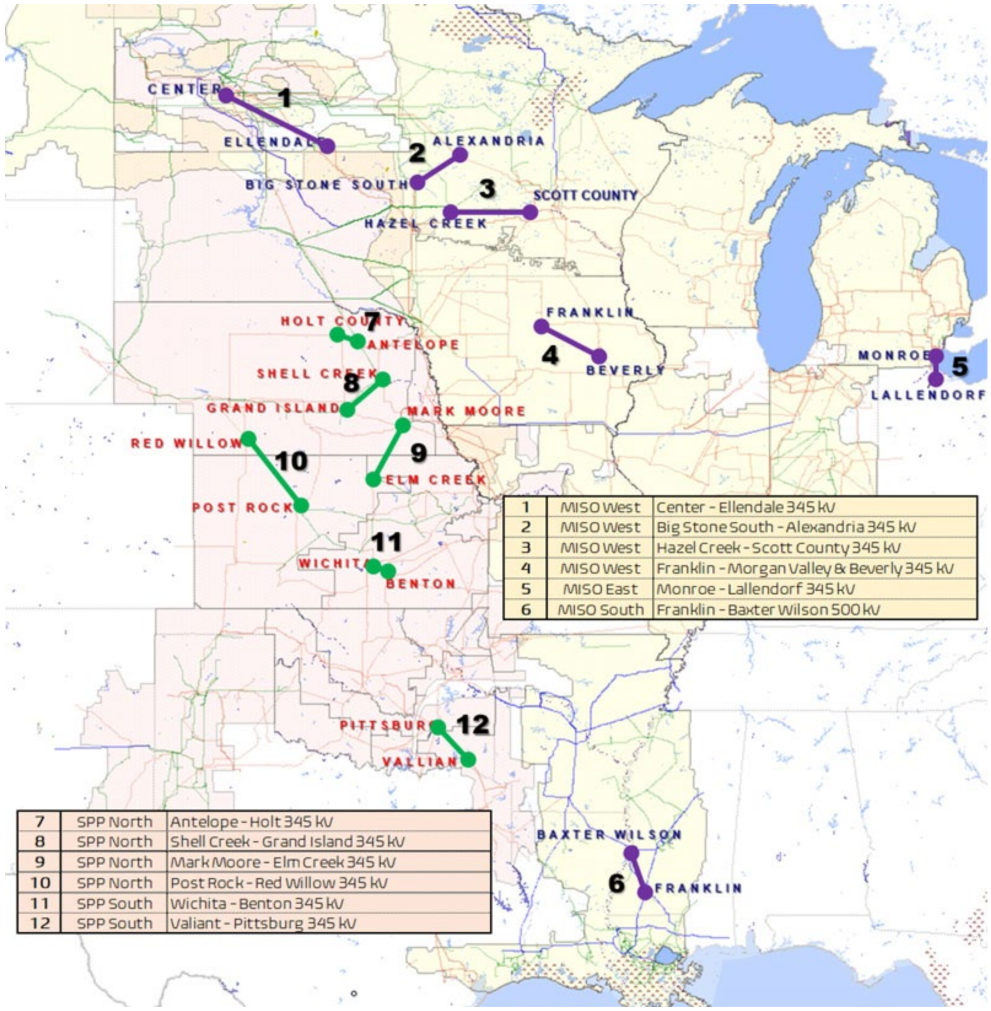
"The big tension seems to be between two principles at FERC," he said. "On the one hand, cost causation, and on the other hand, beneficiary pays. This study shows in many instances, the beneficiary-pays principle in RTO markets is not being fully followed. This, in turn, creates a classic free-rider problem and may result in undue burden being imposed upon developers."

SPP did not respond to the report by press time. A MISO spokesperson said the RTO is focused on its long-range transmission planning initiative and it has not reviewed the study. The grid operator has repeatedly said the plan will support the changing resource mix. (See *MISO Targets March Approval for Long-term Tx Projects*.)

Both RTOs are currently engaged in a joint effort to find interregional transmission projects that can help ease their crowded interconnection queues. (See *MISO, SPP Offer Idea on Joint Interconnection Tx Allocation*.) SPP is also involved in several initiatives to consolidate and improve its own planning process.

ICF worked closely with staff in both regions in developing the assumptions and modeling used in the report, which it produced for ACORE and its Macro Grid Initiative and American Clean Power Association collaborators.

The analysts used "very conservative" assumptions in evaluating the economic benefits of a representative sample of upgrade projects assigned through the MISO and SPP interconnection processes over the last seven years. They screened nearly 230 upgrades spanning four SPP DISIS studies (2014-2017) and 433 network upgrades covering four MISO DPP studies (2016-2020) in shortlisting six network upgrades in each RTO.




| | | |
|---|---|---|
| 1 | MISO West | Center - Ellendale 345 kV |
| 2 | MISO West | Big Stone South - Alexandria 345 kV |
| 3 | MISO West | Hazel Creek - Scott County 345 kV |
| 4 | MISO West | Franklin - Morgan Valley & Beverly 345 kV |
| 5 | MISO East | Monroe - Lallendorf 345 kV |
| 6 | MISO South | Franklin - Baxter Wilson 500 kV |

| | | |
|---|---|---|
| 7 | SPP North | Antelope - Holt 345 kV |
| 8 | SPP North | Shell Creek - Grand Island 345 kV |
| 9 | SPP North | Mark Moore - Elm Creek 345 kV |
| 10 | SPP North | Post Rock - Red Willow 345 kV |
| 11 | SPP South | Wichita - Benton 345 kV |
| 12 | SPP South | Valiant - Pittsburg 345 kV |

The study's 12 short-listed projects in MISO and SPP. | *ACORE*

Ten of the study's 12 network upgrades provided positive adjusted production cost benefits.

The study design, including screening process and criteria to shortlist, was shared with both RTOs' staffs. The final set of shortlisted network upgrades was made after consultation with MISO and SPP. ■

## NYISO News

# New York Adopts Groundbreaking Tx Investment Rules

*By Michael Kuser*

New York regulators on Thursday established a new category of transmission and distribution investments — those made to help achieve the state's environmental goals — and directed investor-owned utilities to revise their proposed benefit-cost analyses and to resubmit them within 90 days (*20-E-0197*).

Citing the urgency of climate challenge and the statutory mandates of the Climate Leadership and Community Protection Act (CLCPA), the Public Service Commission's *order* said that if other changes to proposed investment criteria are warranted in light of changes to the benefit-cost analysis, the utilities are required to file those as well.

The CLCPA requires that 70% of electricity generation come from renewable resources by 2030 and that generation be 100% carbon-free by 2040.

NYPSC Chair John B. Howard | *NYDPS*

"Today does usher in a new era of transmission planning in New York state," said PSC Chair John B. Howard. "Traditional planning by utilities was to serve their native load, specifically, based on a fossil and nuclear-based system. This paradigm will redesign the system to meet renewable goals statewide and will require an unprecedented level of cooperation between transmission owners."

Phase 1 projects are traditional utility investments that address system reliability or resilience issues, while phase 2 projects are investments made primarily for the purpose of achieving CLCPA. The new order on local transmission and distribution planning processes and phase 2 project proposals requires the utilities to work with stakeholders, Department of Public Service (DPS) staff and NYISO to develop and then file a transmission planning process that meets the standards for transparency, consistency of models and coordination established in the order.

The New York Public Service Commission held its regular monthly session in hybrid fashion Sept. 9, meeting both in person and via videoconference. | *NYDPS*

Elizabeth Grisaru, NYDPS | *NYDPS*

"While the order recognizes that this will be a significant effort, it is essential to the implementation of the act and a filing is required within 90 days," Elizabeth Grisaru, deputy director of the DPS Office of Electric Gas and Water, said during the PSC's regular monthly meeting.

The utilities outlined their methodology in a November 2020 *report*, which the state considered in a *study* released by the New York State Energy Research and Development Authority (NYSERDA) and DPS in January. (See *NY Looks to Improve Tx Headroom Assessments*.)

The order noted that mechanisms for cost recovery and cost allocation for this new type of investment do not yet exist and approved the utilities' proposal to charge the costs of phase-2 projects across ratepayers under a volumetric load ratio share allocation.

### Funding and Utilities Forum

The PSC also found that a FERC-approved participant funding agreement among the utilities could establish an equitable system for sharing the costs of these projects. However, additional study is needed on how to implement such an agreement. A further filing on this topic is required within 120 days after consultation with staff, Grisaru said.

The commission rejected the utilities' proposal to bring their potential phase-2 investments into the commission's ongoing rate cases; rather, the commission will establish a specific forum for coordinated review of those projects and their costs from a whole state perspective and on a repeatable cycle.

While the order did not approve any phase-2 projects, it recognized that there are certain areas of the state where renewable generation already is bottled and where additional generation projects are either in development or anticipated, Grisaru said.

The order directs the relevant utility compa-

# NYISO News

nies to address these areas of concern with detailed phase-2 proposals, including options based on their assessment of these areas' development potential. The proposals are due within 180 days.

Lastly, the order adopts staff's recent proposal for revising the way the utilities calculate headroom on the grid — that is the system's ability or capacity to integrate renewable generation in order to support the CLCPA's goals. The order directs the utilities to provide updated headroom data to DPS staff, NYISO and potential bidders no later than Feb. 1, 2022.

During the PSC meeting, Commissioner Diane Burman sought clarification on next steps, including the timeline for the forum for coordinated review of the phase-2 investments.

"Jan. 1, 2023, per the statute for the Accelerated Renewable Energy Growth Act, is supposed to be the kickoff for the commission's first review of this transmission and distribution planning program, so we thought that provided a good touchstone and also provided enough time for the utilities to engage in the revamped planning process that we are contemplating and to produce an effective and well-coordinated portfolio of potential projects," Grisaru said.

In creating a new public policy planning process, the commission identified FERC as the entity that might may be able to assist in terms of rate recovery, and broke the proceeding up into two parts, local distribution and bulk power system issues outside of offshore wind, to make it more manageable, Burman said.

Burman also sought clarification on the status of that process.

"Again referring to the results of the power grid study, we the staff recommended that the commission pay very close attention to the cycle of bulk system studies so as to stay ahead of the bulk system needs that we expect to emerge, particularly as we get into 2030, so we are right now continuing to rely on those processes," Grisaru said. "We expect to take up that question and expect to bring back to this commission some further recommendations relating to the power grid study in a subsequent order."

The commission also approved the second construction phase of the 86-mile, $484 million Smart Path project by New York


NYPSC Commissioner Diane Burman | *NYDPS*

Power Authority in St. Lawrence County, and approved the 12-mile, approximately $100 million Rock Tavern to Sugarloaf transmission project in Orange County by New York Transco.

The latter project is being built in connection with a larger transmission line upgrade known as the New York Energy Solution, which is designed to provide additional transmission capacity to move power from upstate to downstate and is to be operational by December 2023. (See *NYPSC OKs Rebuilding Upstate Tx Lines*.) ■

## NYISO News

# NYISO Updates BSM Revision Proposal

*By Michael Kuser*

NYISO on Thursday presented stakeholders an updated proposal to revise its buyer-side mitigation (BSM) rules, providing new emphasis on addressing capacity accreditation quickly and getting an objective assessment of the proposal's market investment risk.

The ISO has asked its Market Monitor, Potomac Economics, to think through the various market issues and investment risks related to the plan, Michael DeSocio, NYISO director of market design, told the Installed Capacity (ICAP) Market Issues Working Group.

DeSocio highlighted Analysis Group's study to support the BSM reforms proposal, saying "the results of that analysis will be important to inform whether or not the capacity market remains sufficient and effective and can be considered just and reasonable."

NYISO last month introduced the study, which will model 10-year capacity supply and demand curves and identify the resulting market outcomes to support BSM rule revisions. Results will likely be presented later this month, DeSocio said. (See *NYISO Unveils Draft BSM Study*.)

### Policy Resource Exclusion

New York's Climate Leadership and Community Protection Act (CLCPA) requires the state to procure large amounts of renewable energy to get to zero-emission electricity by 2040; the introduction of so much new

Roosevelt Island Tidal Array: Verdant Power's project of three tidal power turbines in the East River is an example of new renewable energy resources coming onto the grid. | *Verdant Power*

# NYISO News

generation will challenge transmission and capacity market planners.

In July, the ISO presented a proposal to exempt most new renewable installed capacity (ICAP) resources from BSM evaluation. (See *NYISO Proposes Sweeping BSM Exemptions*.)

New resources that are required to satisfy the goals specified in the CLCPA will not be subject to review by the ISO under the BSM rules, or otherwise subject to an offer floor. Exempted resources include, but are not limited to wind, solar, storage, hydroelectric technologies (including tidal, ocean and wave generation), geothermal, fuel cells that do not use fossil fuels, and demand response (participating as a special case resource or distributed energy resource).

The proposal represents a two-pronged approach that aims to eliminate BSM risk for CLCPA resources and simplify the currently complex and administratively burdensome BSM process, DeSocio said.

The renewable exemption in its current form would be eliminated, while other existing exemptions, such as competitive entry and self-supply, would remain available to qualifying resources. The current process involving the Part A and Part B offer floor exemption tests would still be performed for resources subject to BSM.

"The set of resources is not fully known that will be meeting those [CLCPA] goals, or at least that seems to be the approach being taken by the state," DeSocio said. "To the extent that the law is clear about these particular technologies, we've tried to accommodate that here."

In response to a stakeholder question about whether hybrid resources would be exempt from BSM review, DeSocio said NYISO would consider them on a case-by-case basis because a hybrid is a mixture of resource technologies. For example, a co-located storage resource comprised of storage plus either solar or wind would be excluded from BSM review because all three technologies are included in the list.

"We don't call it out here for two reasons: first, because we don't have those rules yet, and second, because we've understood the ask from stakeholders for the new hybrid model is to also allow accommodation of fossil resources with storage and other resources. So we don't think we can just make a blanket statement that all hybrid resources would be excluded," DeSocio said.

## Prong Two

The plan's second prong would include additional resource types that satisfy CLCPA, such as technologies New York has identified as supporting state goals or resources that have contracted with NYSERDA to advance those goals.

The topic touches on the various tiers of renewable energy credits and whether a resource is eligible to receive a contract, DeSocio said.

"In other words, it would qualify to receive a contract through maybe one of the tiers or some other program supporting CLCPA that might be run by New York state, whether NYSERDA or some other agency, but it's been mainly NYSERDA executing those contracts," DeSocio said.

Because there could be potential timing issues, the ISO will be looking for the resource to self-certify and provide the ISO evidence that it qualifies under one of the categories. For example, unforced capacity deliverability rights that can demonstrate eligibility for Tier IV RECs would be included under this provision, he said.

One stakeholder said he was curious why the ISO chose to go down the path of painstakingly listing technologies as opposed to a fundamental look at whether the resource is a buyer who can exercise market power. He also wondered whether there are any legal or other downsides to the ISO's approach.

"We chose this path to provide as much clarity to stakeholders as possible about what it means," DeSocio said. "The approach that we laid out here we think gives us the greatest chance of surviving challenge either at FERC or in the courts."

The ISO plans to use the remaining September stakeholder working groups to discuss feedback from Thursdays' meeting, review examples of the probability distribution Delta Method by consultancy E3, hear the report on capacity market investment risk by Potomac Economics, and discuss possible tariff revisions connected with capacity accreditation, he said. ■

## PJM News

# PJM, Stakeholders Respond to MOPR Replacement Challenges

By Michael Yoder

PJM and its stakeholders continue to jostle over the impact of the proposed *replacement* for the expanded minimum offer price rule (MOPR) as responses continue to be filed at FERC (ER21-2582).

In a *motion* filed Sept. 7 with FERC, PJM argued that the commission should "simply accept" the RTO's "focused" MOPR proposal, filed in July, instead of responding to the complaints over the expanded MOPR that was in place for the 2022/23 Base Residual Auction, held in May. PJM argued that an action by the commission on the existing rule "could add needless uncertainty regarding capacity commitments for the 2022/23 delivery year."

It asked that its proposal go into effect starting with the BRA for the 2023/24 delivery year, set for December.

"To resolve the pending appeals upon commission acceptance of the focused MOPR, petitioners could withdraw their petitions, or parties could move to dismiss the case once the expanded MOPR is replaced with the focused MOPR," PJM said in its motion.

The RTO's proposal, which would apply the MOPR only to resources connected to the exercise of buyer-side market power or those receiving state subsidies conditioned on clearing the capacity auction, was endorsed over eight other plans in a special Members Committee meeting in June. PJM filed the proposal in late July after winning final approval from its Board of Managers.

PJM adopted the expanded MOPR after FERC's 2-1 ruling in December 2019 that the rule should apply to all new state-subsidized resources to combat price suppression in the capacity market. Former Chair Neil Chatterjee and fellow Republican Bernard McNamee formed the majority in the decision, while Democrat Richard Glick strongly dissented, calling it an attack on state decarbonization efforts. Glick asked PJM to undo the MOPR rule after he was named FERC chairman by President Biden in January.

Dozens of comments on the extended MOPR started coming into the commission late last month, with PJM stakeholders issuing a mix of support and opposition to the RTO's filing. (See *Mixed Stakeholder Reception to PJM MOPR Replacement*.)


A solar array in Hebron, Md. | *Paradise Energy Solutions*

### PJM Answers

In its motion filed last week, PJM responded to some of the calls by protesters looking to expand or eliminate the MOPR, saying no stakeholder has "rebutted" that its proposal "appropriately protects against exercises of buyer-side market power," while others have not shown that the existing MOPR is "necessary to ensure just and reasonable rates."

PJM said some of the protesters alleged that the focused MOPR "removes all meaningful buyer-side market power mitigation." But the RTO said "none of these allegations undermine the focused MOPR," saying it was designed to "appropriately protect against buyer-side market power" to "ensure just and reasonable outcomes."

Some protesters argued that mitigation approaches need to balance the risks of over-mitigation against those of under-mitigation. But PJM contended that its proposal strikes the appropriate balance between the two by "targeting only those resources that pose a threat of being used in an exercise of buyer-side market power."

The new rule would only be directed at resources that both provide a capacity market seller the ability to exercise buyer-side market power and are offered by sellers with an incentive to exercise buyer-side market power such as a "load-serving responsibility that would benefit from reduced capacity prices." Market participants would be asked to sign attestations declaring they are not exercising market power or receiving state funds tied to clearing in the auction. PJM and the Independent Market Monitor will conduct "fact-specific, case-by-case reviews" if market power is suspected, and referrals will be made to FERC for a final determination.

Several protesters argued that the self-certify provision is "insufficient to prevent the exercise of buyer-side market power" and that existing tariff language does not provide sufficient time for "meaningful review" of the attestations and mitigation before an auction.

PJM said its filing clarified that the self-certification requirement is "not the end of the inquiry with respect to whether an entity can exercise buyer-side market power." It said proposed tariff language includes the "ability for both PJM and the Market Monitor to initiate a fact-specific review of whether a capacity market seller may commit an exercise of buyer-side market power with respect to a certain resource" and that PJM and the Monitor will "ultimately determine whether to apply the MOPR based on the outcome of the inquiry."

### Additional Support

In a joint *motion*, Exelon and Public Service Enterprise Group said the "crux" of many of the arguments against PJM's proposal is that state subsidies for clean-energy suppliers are "inherently uneconomic" and that "state measures to address environmental externalities distort the wholesale markets."

But those arguments "fly in the face of basic economics and the law," the companies said, because the current market construct "protects a $16 billion annual pollution subsidy in PJM to fossil fuel generators by treating that subsidy as a supposedly competitive baseline."

"States, acting within their reserved authority to regulate generation facilities, can reasonably choose to address this market failure and level the playing field by compensating clean-energy generators for their positive externalities of production," they said. "Doing so is not anticompetitive and should not result in mitigation."

Exelon and PSEG said FERC's responsibility to ensure just and reasonable wholesale rates "does not require insulating federal markets

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from the effects of state policies aimed at addressing environmental externalities that would otherwise go unaddressed." Allowing state policies to influence wholesale market outcomes "results in a more efficient set of capacity resources," while opponents of PJM's proposal "proceed on the false premise that efficiency is best achieved by pretending that externalities do not exist."

"This proceeding therefore presents the commission with an important policy question: Is the commission required to insulate the capacity market from the effects of state policies that compensate clean generators for their social benefits in order for market prices to be just and reasonable? Nothing in the Federal Power Act requires that."

A joint *motion* from consumer advocates, including the Delaware Division of the Public Advocate, Maryland Office of People's Counsel, New Jersey Division of Rate Counsel and D.C. Office of the People's Counsel, noted that several entities complained that PJM's proposal "violates their 'rights' as utilities to earn a fair return on their investment" and that it will "undermine investor confidence."

Such objections are "unfounded," the advocates said, and that the proposal "removes unduly discriminatory and protectionist barriers" that limit resources supported through state policies.

"The focused MOPR is pro-competitive because it allows consumers, through state policy, to express qualitative preferences for certain kinds of generation resources, unimpeded by discriminatory and protectionist wholesale capacity rules," they said. "Merchant generators suffer no cognizable harm from the pro-competitive market changes that PJM proposes in its focused MOPR."

### Objections

The PJM Power Providers Group (P3) *said* it's "glaringly apparent" that PJM's proposal lacks support from three major constituencies, pointing to the Monitor, "companies and member organizations who have and would like to continue to invest merchant capital in the PJM region," and representatives in Pennsylvania and Ohio. The group said the two states represent about 40% of the population, load and capacity in the PJM footprint.

Members of the Ohio Senate said the proposal will "severely undermine Ohio's efforts to promote robust and fairly administered competitive electricity markets in our state." (See *Ohio Senate Challenges PJM's MOPR-Ex Filing*.)

P3 said the lack of support of the MOPR-Ex from three key PJM stakeholder groups should "give the commission pause."

"All three of these considerations should prompt the commission to reject the narrow MOPR proposal and invite PJM to submit a just and reasonable alternative," it said. "The problem is not finding agreement that the current MOPR could be improved; rather, the problem is that PJM's proposed solution is a gross overcorrection. The narrow MOPR proposal would destroy the 'guardrails' against buyer-side market power that PJM and its supporters' admit are required by law. The narrow MOPR proposal is the product of a rushed stakeholder process that was focused on getting stakeholder votes, rather than a just and reasonable means of addressing buyer-side market power." ■

## PJM News

# Illinois Senate Passes Landmark Energy Transition Act

### *Includes Bailout for Exelon Nuclear Plants*

*Continued from page 1*

amended and passed an earlier version of the bill on Sept. 9 in an 83-33 vote following angry opposition from Republican members, some of whom noted that the Democrats had ignored their concerns voiced during committee hearings. (See *Illinois House Passes Energy Transition Act*.)

The Senate approved the legislation 37-17, just one vote more than the two-thirds majority required. The vote came after a string of bitter comments from Republican members, many of them from downstate, who saw the legislation as orientated toward Greater Chicago, likely to seriously damage their communities' economies and leading to increased electric bills statewide.

During the debate before the vote, GOP members demanded to know exactly how large the increases in monthly electric bills would be, a question that was not easily answered because state legislative analysts had not yet completed calculations. Estimates ranged from a few dollars to $18 for residential bills. Rates for commercial and industrial customers are expected to be much higher, prompting the Illinois Manufacturers Association last week to testify against the bill.

The passage might have been further delayed had Chicago-based Exelon not announced that it would shut and decommission one of its two reactors on Monday at the Byron nuclear plant without subsidies authorized in the legislation.

Exelon had shut down Unit 1 of Byron overnight for scheduled refueling, but the company announced weeks ago that it would decommission rather than refuel the reactor if the state had not made a decision on a nuclear subsidy included in the bill — nearly $700 million over the next six years. Exelon announced in August that it would close both Byron and Dresden plants without a state or federal subsidy. Each plant has two reactors. (See *Exelon CEO: Looming Nuclear Plant Closures will be 'Irreversible'*.)

The bill sets shutdown targets for all coal and gas power plants in the state over the coming decades, making the nuclear plants key players in a carbon-free future. Exelon operates six nuclear plants in Illinois, five of which include two reactors.

The legislation requires all investor-owned baseload coal-fired power plants and remaining oil peaker turbines to shut down by 2030. The municipally owned Prairie State coal plant, with customers in six states, must reduce its emissions by 45% by 2035 through carbon capture and sequestration and must shut down by 2045, unless it can curtail all of its carbon dioxide emissions. City Water, Light and Power, the Springfield municipal power operation, which heats and lights the State House, will face the same shutdown rule.

Gas turbine plants, even those now under construction, must also close by 2045 under the terms of the bill, although the state would have an option to allow continued operation if they are critically needed: in other words, if the anticipated growth in renewable energy — from 7% currently to 100% by 2045 — cannot be achieved.

The bill also allocates hundred of millions of dollars to expand solar installations, both on a community solar level and homeowner rooftop solar. Electric vehicle purchase rebates of $4,000 are also in the legislation, but only in certain counties where local governments will collect to finance the rebates.

Pritzker, labor supporting the continued operation of the nuclear plants, environmental groups such as the Sierra Club and the National Resources Defense Council, and a number of renewable energy trade groups coalesced over the past year to push for the bill.

In a statement issued Monday afternoon, Pritzker said the passage is "historic."

"Today, with the Senate passage of SB 2408, the state of Illinois is making history by setting aggressive standards for a 100% clean energy future. After years of debate and discussion, science has prevailed, and we are charting a new future that works to mitigate the impacts of climate change here in Illinois."

A statement from the Path to 100 Coalition of renewable energy advocates said the passage of the bill "puts Illinois at the forefront of the fight against climate change all while creating tens of thousands of jobs, expanding diversity in the renewable energy industry and providing more than $1 billion in electricity bill savings for consumers."

"Opening the Illinois market is critical to the growth of energy sources that will clean the air, create jobs and jumpstart the state's economy," asserted Abigail Ross Hopper, CEO of the Solar Energy Industries Association. "Illinois is now a national leader in crafting renewable energy solutions."

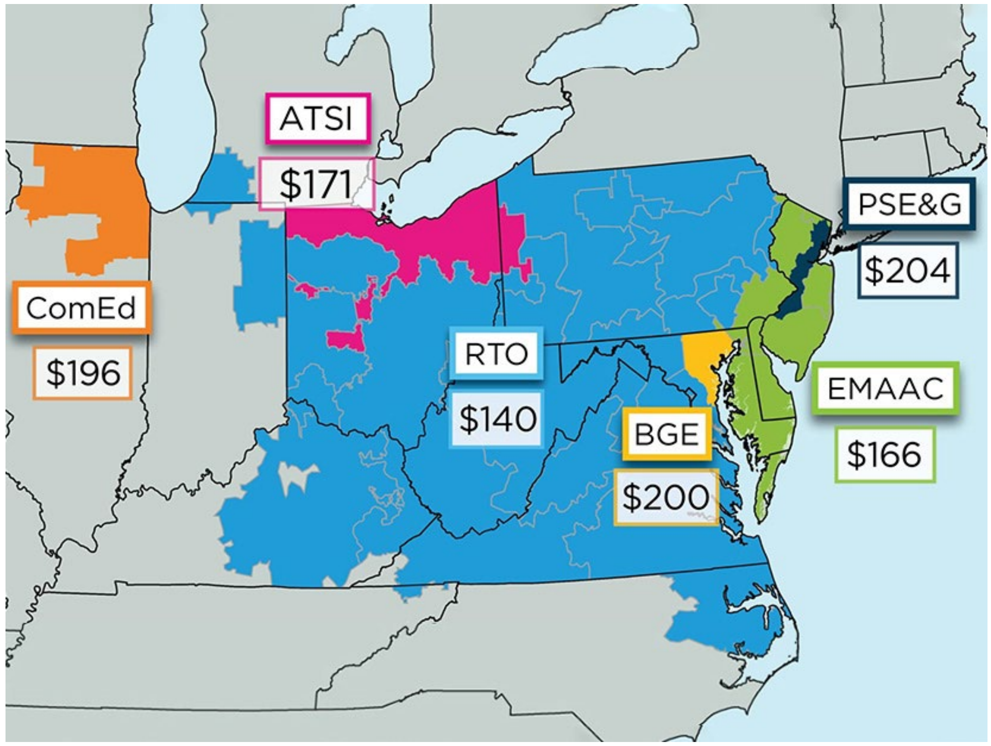
Advanced Energy Economy called the bill "the most significant climate and clean energy legislation" in the history of the state. ■

Unit 1 of Exelon's Byron nuclear power plant in Illinois shut down early Monday for re-fueling or for decommissioning if Illinois lawmakers failed to approve legislation providing nearly $700 million in public funding over six year for its Byron and Dresden nuclear plants that the company said cannot compete against gas turbines and subsidized renewable energy | *Ben Jacobson, CC BY-2.5, via Wikimedia*

# PJM News

# PJM Proposing 2-Month Capacity Auction Delay

*By Michael Yoder*




PJM's Independent Market Monitor contends ratepayers were overcharged by $2.7 billion (41.5%) in the 2018 Base Residual Auction because of economic withholding encouraged by an inflated market seller offer cap. | *PJM*

PJM is asking FERC to delay the Base Residual Auction for the 2023/24 delivery year by almost two months, citing the commission's Sept. 2 order revising the RTO's market seller offer cap (MSOC).

In a compliance filing Friday, PJM recommended delaying the start of the 2023/24 BRA by 55 days, from Dec. 1 until Jan. 25, 2022 and the 2023/24 third incremental auction from Feb. 27, 2023 to March 21, 2023 (*ER21-2877*).

The filing also seeks to change the starts of subsequent Reliability Pricing Model (RPM) auctions, moving the 2024/25 BRA from June 15, 2022 to Aug. 9, 2022; the 2025/26 BRA from Jan. 4, 2023 to Feb. 28, 2023, and the 2026/27 BRA from March 17, 2023 to Aug. 29, 2023.

PJM said changing the dates of the RPM auctions is necessary to maintain the six-and-a-half-month gap between auctions so that market participants "have sufficient time to review the results of each auction before deciding whether to continue offering a resource in the subsequent auction."

The RTO said its request was prompted by FERC's Sept. 2 order adopting the Independent Market Monitor's unit-specific avoidable cost rate (ACR) proposal and requiring PJM to revise its tariff (*EL19-47, EL19-63, ER21-2444*). The Monitor's proposal followed FERC's March order requiring PJM to revise the MSOC to prevent sellers from exercising market power in the capacity market. (See *FERC Backs PJM IMM on Market Power Claim*.) The RTO said the auction delay was necessary to give capacity market sellers and the Monitor a "realistic opportunity" to appeal the RTO's final decisions on unit-specific offer cap requests resulting from the MSOC rules change.

"PJM does not make the decision to seek a further delay of the already delayed upcoming BRA lightly," the RTO said in its filing. "PJM strongly believes the three-year forward nature of the capacity auctions is a critically important feature of the Reliability Pricing Model construct and would prefer to expeditiously conduct the upcoming auctions without delay. At the same time, however, given the expected volume of unit-specific requests stemming from the significant change to the MSOC rules, PJM believes that a revised timeframe must be established to allow for an orderly and complete Market Monitor and PJM review of all such requests."

## Stakeholder Opinions

PJM received mixed feedback on the proposed delay at last week's Market Implementation Committee meeting.

Pete Langbein, PJM | *© RTO Insider LLC*

Chen Lu of PJM *provided* an overview of the capacity MSOC order, while Pete Langbein, manager of PJM's demand side response operations, presented the *draft timelines* for the pre-auction activities for the upcoming BRA impacted by the order and the timing of the auction.

Langbein said PJM attempted to focus the timeline changes on the pre-auction tasks and activities that were "clear and transparent" to avoid stakeholder confusion. Langbein said the RTO was searching for a way so stakeholders would have a "reasonable amount of time" to finish their activities for the auction.

"The BRA auction and the associated timeline is pretty complicated, and there are a lot of dependencies between the different activities," Langbein said. "There's a bit of a dance to make all these different dates work."


Paul Sotkiewicz, E-Cubed Policy Associates | *© RTO Insider LLC*

Paul Sotkiewicz of E-Cubed Policy Associates said he thought it would be better for his clients to have PJM compress the timeframe and "keep the auctions moving on time."

"When is it going to end?" Sotkiewicz asked.

Jason Barker of Exelon said he appreciated PJM's attempt to balance the "orderly administration of the auction" by proposing a delay. But Barker said Exelon "tilted towards" the idea of keeping the December auction on schedule and that one of the company's biggest concerns with changing dates was the possibility of having to redo any ACR submittals that had already been submitted.

Market Monitor Joe Bowring said that, without a delay, generation owners would

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have eight days to complete their ACR filings, which would be "close to impossible" for anyone having to make new ACR submittals.

"We all like to live in a completely certain world with certain deadlines, but that's not where we are," Bowring said, adding that PJM is "likely to see some more uncertainty" in the capacity auctions when the minimum offer price rule (MOPR) order is finally decided.

Jim Benchek of FirstEnergy said he would "urge" PJM to file the delayed schedule. Benchek said if a market seller didn't anticipate having to go through the unit-specific net ACR calculation process, completing the process in eight days is "almost an impossible amount of time."

"You need to afford market sellers the right amount of time to do things thoroughly and correctly," Benchek said.

Langbein said no matter what timeline is ultimately approved by FERC, the process is going to be new for many stakeholders and will create a large volume of requests.

"We do not believe this is something administrative that's going to be easy to do," Langbein said.

## MSOC Order

In March, the commission ordered PJM to revise its MSOC, siding with arguments made in separate complaints filed in 2019 by the IMM and several consumer advocate groups that challenged the RTO's Capacity Performance (CP) assumptions and arguing the existing rules were allowing sellers to exercise market power.

In August 2018, the Monitor concluded that PJM ratepayers were overcharged by $2.7 billion (41.5%) in the 2018 BRA because of "economic withholding" encouraged by the inflated MSOC. (See *IMM: PJM 2018 Capacity Auction was 'Not Competitive'*.)

Unit-specific MSOCs are to be based on avoidable costs and the opportunity cost of taking on a CP obligation, the Monitor said, including expectations of bonus payments or penalties for performance during an emergency. The timespan for measuring performance was changed from PAHs to five-minute performance assessment intervals (PAI) in compliance with FERC Order 825 in 2018.

A PAI is triggered when PJM determines a supply reliability issue exists, providing credits for generators that overperform their capacity commitments and penalties for those who underperform.

The Monitor originally suggested using 60 PAIs or five PAHs — compared with the current 360 PAIs/30 PAHs — in calculating a more appropriate seller cap.

FERC ordered PJM and its stakeholders to determine a suitable replacement rate within 45 days of the filing in March, addressing the "appropriateness of using different values" for penalty PAI and expected PAI in the default CP MSOC calculation and a method for setting each value.

Ultimately the IMM's unit-specific ACR *proposal* filed on April 28 won out over three other proposals submitted to the commission.

The unit-specific ACR proposal said offers should be capped at the resource's unit-specific net ACR, meaning "unit-specific gross ACR minus forward-looking net energy and ancillary service revenues, with the option to use the technology-specific default gross ACRs minus unit-specific forward-looking net energy and ancillary service revenues." The Monitor said the commission recently accepted technology-specific default gross ACRs in the MOPR proceeding.

The IMM said its proposal would be a "return to the requirements prior to the introduction of CP, when offers were capped at unit-specific net ACR." The Monitor said it already has experience with calculating unit-specific and default net ACR offer caps in the capacity market, and the process is "manageable from an administrative perspective" as the PJM tariff already includes a formula for the unit-specific gross ACR review.

FERC said the unit-specific ACR proposal was preferable to the three other options presented to the commission because it would "best ensure the capacity market's overall competitiveness and enable the Market Monitor and PJM to sufficiently review and mitigate offers to prevent the exercise of market power."

**AUCTION OPENING DATE**

| Auction | Current | Proposed |
|---|---|---|
| 2023/24 BRA | Dec. 1, 2021, Wed | **Jan. 25, 2022, Tue** |
| 2022/23 Third IA | Feb.28, 2022, Mon | Feb. 28, 2022, Mon |
| 2024/25 BRA | June 15, 2022, Wed | **Aug. 9, 2022, Tue** |
| 2025/26 BRA | Jan. 4, 2023, Wed | **Feb. 28, 2023, Tue** |
| 2023/24 Third IA | Feb. 27, 2023, Mon | **March 21, 2023, Tue** |
| 2026/27 BRA | May 17, 2023, Wed | **Aug. 29, 2023, Tue** |
| 2024/25 Second IA | July 31, 2023, Mon | July 31, 2023, Mon |
| 2024/25 Third IA | Feb. 26, 2024, Mon | Feb. 26, 2024, Mon |
| 2025/26 Second IA | July 15, 2024, Mon | July 15, 2024, Mon |
| 2026/27 First IA | Sept. 9, 2024, Mon | Sept. 9, 2024, Mon |
| 2025/26 Third IA | Feb. 24, 2025, Mon | Feb. 24, 2025, Mon |
| 2026/27 Second IA | July 14, 2025, Mon | July, 14, 2025, Mon |
| 2026/27 Third IA | Feb. 23, 2026, Mon | Feb. 23, 2026, Mon |

Proposed date changes

PJM's updated RPM auction schedule through the 2026/27 delivery years. | *PJM*

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"We recognize that eliminating the default offer cap will likely create more work for the Market Monitor and sellers by requiring the individual review of a higher number of capacity offers," the commission said in its order. "But we find that such review is reasonable and needed to address potential market power abuse in PJM. The other proposals would result in the review of fewer offers, and potentially not the marginal offer(s), and therefore be less effective at identifying and mitigating the exercise of market power in PJM."

Commissioner James Danly dissented from the Sept. 2 order, saying it "risks over-mitigation." Danly said fixing the default offer cap would be a "far better solution than the alternative supported by the majority," which "jettisons" the offer cap for a "full unit-specific review of all offers above zero."

Danly said the unit-specific review will give "extraordinarily broad new powers" to the IMM to "second guess" the judgment of market sellers. He said the commission will be the only "check" on the review powers of the Monitor and that FERC "should not be in the business of determining seller offers in advance of auctions."

"There are problems with the current default offer cap, but unit-specific review of all resources is far too invasive a 'remedy,'" Danly said. "It should be clear to anyone paying attention that PJM's market design is becoming increasingly discriminatory against existing generators. It is swift becoming unduly so. And the more we redesign our markets into elaborate cost-justification exercises, the fewer of the benefits promised by markets can be realized."

## PJM Filing

Besides adopting the IMM's proposal, FERC also accepted a waiver request filed by PJM in July regarding certain pre-auction deadlines in the event a lower value for the replacement default offer cap was established (*ER21-2444*).

In Friday's filing, PJM said the potential volume of unit-specific requests stemming from the "significant change to the offer cap rules" necessitates establishing a new timeframe that "allows for orderly and complete IMM and PJM review of all such requests, and the ability for stakeholders to appeal PJM's final decisions to the FERC prior to executing the auction."

"There is simply no realistic scenario for PJM and the Market Monitor to review and make final unit-specific offer cap and must-offer determinations more than 60 days prior to the currently scheduled Dec. 1, 2021 BRA," PJM said in its filing. "This modest delay will allow 60 days for capacity market sellers and the Market Monitor to seek remedies from the commission prior to the commencement of the next BRA. This is necessary and appropriate given PJM's expectation that many capacity market sellers and/or the Market Monitor will inevitably disagree with the final unit-specific offer cap determinations. Indeed, based on the information currently available to PJM, none of the unit-specific offer caps requested to date under the existing pre-auction deadlines for the 2023/2024 BRA have been accepted by the Market Monitor."

| Activity Type | Activity | Current Dates | Proposed Dates |
|---|---|---|---|
| Must Offer | Last day for Capacity Market Sellers to request must-offer exception for the reason specified under OATT Attachment M-Appendix § II.C.4.A | 7/19/21, Mon | 10/1/21, Fri |
| Sell Offer Caps | Last day for Capacity Market Sellers to submit sell offer cap data | 8/3/21, Tue | 10/1/21, Fri |
| Sell Offer Caps | IMM provides participant with determination of offer cap | 9/2/21, Thu | 10/31/21, Sun |
| Must Offer | IMM provides participant with determination on must offer exception | 9/2/21, Thu | 10/31/21, Sun |
| Sell Offer Caps | Last day for Capacity Market Sellers to notify PJM/IMM of agreement with IMM determination of offer cap | 9/12/21, Sun | 11/5/21, Fri |
| Must Offer | Last day for Capacity Market Sellers to notify PJM/IMM of agreement with IMM determination on must offer exception | 9/12/21, Sun | 11/5/21, Fri |
| Sell Offer Caps | PJM notifies participant/IMM of determination on proposed offer cap | 9/27/21, Mon | 11/25/21, Thu |
| Must Offer | PJM notifies participant/IMM of its determination on must offer exception for the reason specified under OATT Attachment M-Appendix § II.C.4.A | 9/27/21, Mon | 11/25/21, Thu |
| Must Offer | Last day for Capacity Market Sellers to notify PJM/IMM whether it intends to exclude from its Sell Offer some or all capacity from its generation resource on the basis of an identified exception to the RPM Must Offer Obligation | 9/27/21, Mon | 11/25/21, Thu |

Current and proposed dates for the 2023/24 Base Residual Auction market seller offer cap-related pre-auction activities | *PJM*

PJM's proposal calls for new deadlines for capacity market sellers to submit a must-offer exception request associated with resource deactivations and a unit-specific offer cap, moving the current deadline dates of July 19 and Aug. 3 to Oct. 1. The RTO said the new deadlines provide market sellers three weeks to determine whether to seek a unit-specific offer cap and to prepare necessary supporting documentation.

"Consolidating the deadline for these submissions to the same date will save some time and allow PJM to conduct the upcoming BRA without significant additional delays," the RTO said.

PJM also proposed to push back the deadline for the IMM to review and propose a recommendation on market sellers' unit-specific offer cap and/or must-offer exception request associated with resource deactivations to Oct. 31. The RTO said the change will give the Monitor its usual 30-day period from the unit-specific offer cap and must-offer submission deadline to "review and provide its proposed recommendation of various unit-specific offer cap and must-offer exception requests."

The schedule changes provide market sellers with five days to review the IMM's recommendation and notify PJM and the Market Monitor whether it agrees with the unit-specific offer cap or must-offer exception associated with resource deactivations proposed by the Market Monitor.

PJM said it proposed to maintain the normal 25-day period for the RTO to make its final determination on disagreements in the unit-specific offer cap and/or must-offer exception requests, setting the date at Nov. 25 instead of Sept. 27.

"Capacity market sellers will all retain the opportunity to offer resources into the RPM auction sufficiently in advance of the delivery year even with this modest delay and resources that clear the auction will continue to receive capacity revenues during the delivery year," PJM said. ■

PJM News

# PJM Operating Committee Briefs

## Manual 14D Endorsed

PJM stakeholders unanimously endorsed manual updates related to behind-the-meter generation (BTMG) business rules on status changes developed in special sessions of the Market Implementation Committee.


Terri Esterly, PJM | © RTO Insider LLC

Terri Esterly, senior lead engineer in PJM's markets automation and quality assurance department, reviewed Manual 14D: Generator Operational Requirements updates to appendix A during last week's Operating Committee meeting. Stakeholders endorsed related changes to Manual 14G at the Aug. 31 Planning Committee meeting. (See "Manual 14G Updates Endorsed," *PJM PC/TEAC Briefs: Aug. 31, 2021*.)

Esterly said PJM made no changes to the updates since she first presented the manual changes at the August OC meeting. (See "Manual 14D Updates," *PJM Operating Committee Briefs: Aug. 12, 2021*.)

The updates to Manual 14D were intended to address conflicts with the Reliability Pricing Model must-offer requirement and "removal from generation capacity resource status" business rules, Esterly said. Updates included addressing performance obligation impacts, clarifications to business rules regarding load impacts from status changes, and participation in PJM's load response.

In a section on designating capability as a generation capacity resource and/or an energy resource, PJM added a business rule to make it clear a new service request must be submitted for the designation, Esterly said. Another rule was made to clarify the process to request a change from BTMG status to generation capacity resource status.

In the section on participation in PJM load response, Esterly said the RTO added the process to indicate that a BTMG unit is participating in PJM load response by providing on-site generator data.

The manual updates now go to the Sept. 29 Markets and Reliability Committee meeting for a first read and endorsement at the Oct. 20 MRC meeting.

## Manual 01 Changes

A manual attachment created last year in the wake of COVID-19 emergency protocols is set to become permanent and changed to address other emergency situations.

Chris Moran, senior lead analyst with PJM's NERC compliance team, provided a first read of updates to Manual 01 Attachment F: Control Center and Data Exchange Requirements regarding the RTO's market operation centers being able to conduct remote operations.

Moran said attachment F of Manual 01 was originally developed and implemented at the start of the COVID-19 pandemic to provide guidance for remote operations "should imminent risk of COVID-19 start to affect staffing" in PJM's market operation control centers. The temporary attachment, which became effective in April 2020, was set to expire on Dec. 31 of this year.

As the pandemic has progressed, Moran said, it has "become apparent" to PJM that attachment F needs to become a permanent part of Manual 01. Several stakeholders also had suggested making the attachment permanent at a previous OC meeting. (See "COVID-19 Update," *PJM Operating Committee Briefs: June 10, 2021*.)

Moran said PJM wanted to make attachment F broader so that it doesn't simply apply to COVID-19. The language changes include replacing COVID-19 with "exceptional circumstances," which include severe weather, natural disasters, civil unrest and other pandemic events.

PJM's definition for exceptional circumstance says, "an event or effect that can be neither anticipated nor controlled, including but not limited to any act of a public enemy, war, insurrection, riot, fire, severe weather, natural disaster, flood, civil unrest, explosion, pandemic or other public health emergency, as reasonably determined by PJM."

The attachment changes also include updating NERC compliance contact information for PJM.

The OC will vote on the manual changes at its October meeting.

## COVID-19 Update

Becky Carroll of PJM provided an update on the RTO's response to COVID-19, saying staff is reviewing Occupational Health and Safety Administration rules regarding vaccinations recently announced by the Biden administration.

Carroll said PJM is "still evaluating" the new rules that would require vaccinations or a weekly negative COVID-19 test for any company over 100 employees. She said PJM will be communicating more details to its employees and stakeholders following consultation with the RTO's legal counsel, its epidemiologist and the executive team.

"As we're thinking about this new rule, we'll be taking the safety and wellbeing of PJM staff into account, given that's paramount," Carroll said.

Some PJM stakeholders have been arguing for several months that the RTO should mandate vaccinations for all its employees. (See "COVID-19 Update," *PJM Operating Committee Briefs: Aug. 12, 2021*.)

Ken Foladare of Tangibl Group said he understands that PJM must consult with its legal counsel over the regulations, but he said other large organizations already had mandated vaccines for their employees to come back to the office. Foladare said he found it "disappointing" that PJM had not taken similar measures to mandate vaccines.

Mike Bryson, PJM's senior vice president of operations, said the RTO "continues to appreciate" the positions of stakeholders. Bryson said PJM CEO Manu Asthana has had discussions with senior leadership of member companies about their stance on vaccinations.

"We continue to evaluate the way our posture has been in the interest of protecting staff that has to come on campus," Bryson said.

Adrien Ford of Old Dominion Electric Cooperative asked if there has been any change in PJM's plan to have staff return to the Valley Forge campus given the rising cases of COVID-19. Staff were originally scheduled to start coming back to the campus by Sept. 1.

Carroll said PJM is evaluating the plan to return to campus "on a two-week basis" and have delayed the return until the middle of September. She said staff will receive another update on Sept. 13 to determine if they can return to campus or delay it for another two weeks.

"We are going to continue to evaluate on a two-week cycle," Carroll said. ■

*— Michael Yoder*

## PJM News

# PJM MIC Briefs

### Regulation Mileage Ratio Calculation Endorsed

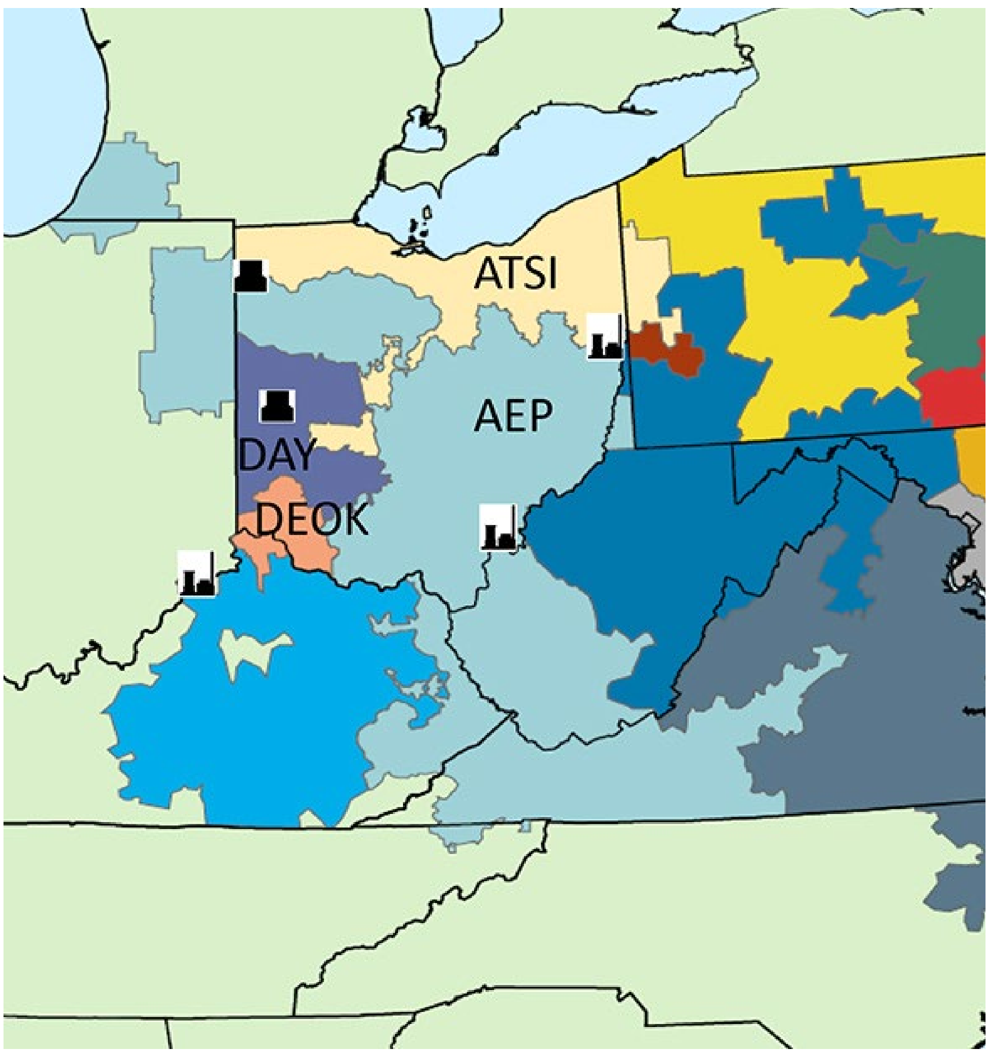
Stakeholders endorsed *PJM*'s proposal to change the undefined regulation mileage ratio calculation after several months of debate over what number to use in the calculation.

PJM's proposal, which called for setting the RegA dispatch mileage floor at 0.1 instead of zero, was endorsed with 152 votes in favor (64%) at last week's Market Implementation Committee meeting. In a vote asking if stakeholders supported the PJM proposal over the status quo, the plan was endorsed with 147 votes in favor (67%).

Members had originally delayed adopting the RegA dispatch after a unanimous vote to amend PJM's issue charge at the July MIC meeting, requesting to remove the suggested "quick fix" process from the proposal and instead handle discussions under an abbreviated consensus-based issues resolution process. (See "Regulation Mileage Ratio Delayed," *PJM MIC Briefs: July 14, 2021*.)

PJM originally sought to work the issue through the quick-fix process in Manual 34 and take final votes at the July Operating Committee, Markets and Reliability Committee and Members Committee meetings. But several stakeholders challenged the proposed solution of updating values in the regulation mileage ratio, saying it was too complicated to address through the quick-fix process. (See "Regulation Mileage Ratio First Read," *PJM MRC/MC Briefs: June 23, 2021*.)

Michael Olaleye, senior engineer with PJM's real-time market operations, *reviewed* the RTO's proposed solution. Olaleye said PJM had not received any additional feedback from stakeholders since the issue was discussed at the August MIC meeting, and no changes had been made to the proposal.




Buckeye Power generation and load map | *Buckeye Power*

Regulation mileage is the measurement of the amount of movement requested by the regulation control signal that a resource is following; it is calculated for the duration of the operating hour for each regulation control signal. PJM's performance-based regulation market splits the dispatch signal in two: RegA for slower-moving, longer-running units; and RegD for faster-responding units that operate for shorter periods, including batteries. If a signal is "pegged" high or low for an entire operating hour, the corresponding mileage would be zero for that hour.

Olaleye said PJM has seen an increased frequency of RegA signal pegging and times the RegA signal is pegged for extended periods, highlighting a potential problem in the regulation mileage ratio calculation. The RegA mileage can be set at zero for a given hour and create a divide-by-zero error in the calculation of the mileage ratio.

PJM proposed setting the RegA mileage floor at 0.1 instead of zero, Olaleye said, which would allow for a "valid solution" for the ratio and still maintain market design objectives. He said the change would have no impact on the regulation signal design, operations or regulation market clearing.

PJM Monitor Joe Bowring | © *RTO Insider LLC*

Independent Market Monitor Joe Bowring presented a *counterproposal*, questioning PJM's use of the 0.1 value. The IMM proposed a cap of 5.5 on the realized mileage ratio in all hours, indicating the cap would eliminate the current undefined mileage ratio result that PJM is attempting to address.

Bowring said the 5.5 cap would reduce but not eliminate the market distortion resulting from the use of mileage ratios when they incorrectly represent regulation output and that the change would affect less than 50% of impacted hours based on data collected by the IMM over the last 15 months.

Stakeholders ultimately rejected the IMM proposal, with 129 members voting against

# PJM News

adoption (56%).

Gary Greiner, PSEG | © RTO Insider LLC

Gary Greiner, director of market policy for Public Service Enterprise Group, said the IMM's proposal was "a lot more comprehensive," and the solution suggested that there's a problem with the way that the mileage ratio works. Greiner said it seemed the quick fix path was "not the right path to go down" if the problems are as comprehensive as the IMM's proposal indicates.

Greiner said the divide-by-zero error could be solved "pretty easily without a lot of impact" by adopting PJM's 0.1 proposal and come back with a more extensive stakeholder process in the future to address the milage ratio issues brought up by the IMM.

## RPM Capacity Transfer Rights Rejected

A proposal by Buckeye Power to address the allocation of capacity transfer rights (CTRs) failed to win stakeholder approval.

Members rejected the proposal worked on for the last six months in the MIC, with only 55 voting in support (28%). Stakeholders originally endorsed Buckeye's issue charge at the March MIC meeting with 79% support. (See "RPM Issue Charge Endorsed," *PJM MIC Briefs: March 10, 2021*.)

Kevin Zemanek, director of system operations for Buckeye Power, *reviewed* Buckeye's proposal regarding the allocation of CTRs, saying under the Reliability Pricing Model (RPM), CTRs return to load-serving entities (LSEs) capacity market congestion revenues that occur when there's a difference between the prices paid by load and market revenue received by cleared resources. CTRs permit LSEs with load inside a constrained locational delivery area (LDA) to receive a credit for the import of capacity from a lower-priced region. (See "RPM Capacity Transfer Rights," *PJM MIC Briefs: Aug. 11, 2021*.)

PJM does not have a way to allocate CTRs directly to an LSE with network resources outside a constrained LDA but whose resources have been designed as deliverable on the LSE's network integration transmission service agreement. Instead, Zemanek said, PJM allocates CTRs pro rata to each LSE serving load in the LDA or zone based on the LSE's share of the zonal unforced capacity obligation.

Buckeye's proposal called for first allocating zonal CTRs to LSEs with historic generation resources identified as network resources in a network integration transmission service agreement (NITSA). The allocated CTRs will be "sufficient to meet the LSE's daily unforced capacity (UCAP) load obligation but shall not exceed the total amount of the LSE's generation capacity as identified on the LSE's NITSA."

Buckeye said the impact of the current rules vary from year to year; it said the rules cost it $10 million in the 2015/16 delivery year and $2.5 million in 2016/17.

The proposal would have recognized generation resources and transmission rights that existed prior to the implementation of RPM but would also terminate upon the retirement of a resource or a change in the designated resource status in the NITSA.

"These are not evergreen and would not last forever," Zemanek said. "Based on the historical situations, we think this is minimal impact."

Bowring said the IMM believes it's inconsistent to use prior contracts to calculate network congestion. The current CTR process "certainly needs to be revisited" in the review of the PJM capacity market, he said, but it wasn't appropriate to reevaluate it on a "one-off basis" with Buckeye.

"To the extent Buckeye is paid more, others will be paid less," Bowring said. "And we don't agree that there's been any detailed analysis of what the ultimate impact will be."

## Peak Shaving Plan

Ed Rich, senior analyst with PJM's capacity market operations, *provided* a first read of the

| Local Hour | RMCCP | RMPCP | Hourly Mileage A | Hourly Mileage D | Hourly Mileage Ratio (settled) | Hourly Mileage Ratio (Proposed) | Difference in Mileage Ratio |
|---|---|---|---|---|---|---|---|
| 3/4/2013 18:00 | $37.67 | $0.03 | 0.074304 | 0.257536 | 3.47 | 2.58 | 0.89 |
| 11/9/2013 18:00 | $12.40 | $0.97 | 0.072887 | 15.649591 | 214.71 | 156.5 | 58.21 |
| 5/31/2015 15:00 | $187.06 | $0.78 | 0.070406 | 14.128501 | 200.67 | 141.29 | 59.38 |
| 12/11/2015 16:00 | $12.49 | $0.01 | 0.078511 | 13.35094 | 170.05 | 133.51 | 36.54 |
| 12/31/2015 18:00 | $0.27 | $0.00 | 0.056789 | 12.54787 | 220.96 | 125.48 | 95.48 |
| 1/1/2016 2:00 | $8.45 | $0.00 | 0.013579 | 10.582214 | 779.31 | 105.82 | 673.49 |
| 6/28/2016 16:00 | $3.08 | $0.00 | 0.018116 | 11.818568 | 652.38 | 118.19 | 534.19 |
| 2/27/2018 9:00 | $0.00 | $0.00 | 0.040318 | 20.448624 | 507.18 | 204.49 | 302.69 |
| 1/21/2019 11:00 | $313.49 | $0.00 | 0.006478 | 27.402607 | 4230.10 | 274.03 | 3956.07 |
| 1/30/2019 14:00 | $17.49 | $0.01 | 0.046133 | 5.225629 | 113.27 | 52.26 | 61.01 |
| 6/22/2020 15:00 | $0.01 | $0.00 | 0.048004 | 19.204105 | 400.05 | 192.04 | 208.01 |
| 6/26/2020 0:00 | $11.37 | $0.00 | 0.096609 | 23.562192 | 243.89 | 235.62 | 8.27 |
| 8/12/2020 14:00 | $15.09 | $0.01 | 0.03332 | 22.412721 | 672.65 | 224.13 | 448.52 |
| 2/17/2021 9:00 | $0.00 | $0.00 | 0 | 19.159495 | #N/A | 191.59 | 191.59 |
| 4/2/2021 4:00 | $8.59 | $0.00 | 0.099567 | 6.182331 | 62.09 | 61.82 | 0.27 |
| 4/15/2021 9:00 | $6.91 | $0.00 | 0.052218 | 33.582262 | 643.12 | 335.82 | 307.30 |
| 5/8/2021 13:00 | $13.77 | $0.00 | 0.011427 | 31.296327 | 2738.81 | 312.96 | 2425.85 |

Instances of RegA hourly mileage rates less than 0.1 in PJM since 2013 | *PJM*

# PJM News

*problem statement*, *issue charge* and *solution* addressing the peak shaving adjustment shortfall calculation in attachment D of Manual 19 through the "quick fix" process.

Rich said the peak shaving performance rating is used to correct the impact of approved peak shaving programs in the load forecast to be consistent with how the programs have performed when required to reduce load.

The current documented calculation for the megawatt shortfall in Manual 19 says, "For each hour of a required peak shaving event, a shortfall value is calculated as the aggregated metered load of all participants minus their aggregated customer baseline (CBL)." Rich said PJM has determined that the calculation is "erroneous" since "taking the difference of the metered load and the customer baseline will only calculate a shortfall value when a resource does not reduce but has a greater metered load than the customer baseline."

Rich said PJM is proposing to change the shortfall value calculation as the "resource's total participating megawatt minus the difference of their customer baseline (CBL) minus their metered load adjusted for line losses, capped at zero."

Rich said the issue found by PJM has caused no incorrect shortfalls to be calculated because no peak shaving plans have been submitted and cleared in a capacity auction since the program was created.

To simplify the calculation of the performance rating of peak shaving plans, Rich said, PJM is also proposing calculating a yearly total performance rating instead of a performance rating by event. He said the change will eliminate PJM calculating an average yearly performance rating and instead use the total yearly performance rating for calculating the rolling average performance.

"Instead of taking the average shortfall per event, using the total calculations for the year would be a more accurate representation of their total performance rating," Rich said.

Bowring said he was a "little surprised" PJM was putting the issue through the quick fix process given that the key work activities and scope include providing background education on the issue. He said the issue could use more stakeholder discussion to grasp the concepts being changed.

"I certainly don't totally understand what's happening here," Bowring said. "I don't know if everybody else does."

## Manual 15 Revisions Endorsed

Stakeholders unanimously endorsed manual changes regarding the incremental and no-load energy offers.

Tom Hauske of PJM's performance compliance department *reviewed* the Manual 15: Cost Development Guidelines *revisions* regarding the incremental and no-load energy offer developed in the Cost Development Subcommittee (CDS). Hauske first introduced the revisions at the August MIC meeting. (See "Manual 15 Revisions," *PJM MIC Briefs: Aug. 11, 2021*.)

Hauske said the CDS proposed revising the no-load cost and incremental energy offer definitions to clearly define what costs can be included, including operating costs, tax credits and emissions allowances. He said Manual 15 also had to be restructured to provide more guidance to market sellers on the calculation of their no-load and incremental energy cost offers.

"There are a lot of wholesale changes in Manual 15," Hauske said.

The most significant manual changes came in section 2.3 for the definition of incremental energy cost, Hauske said, which states, "The incremental energy cost is the cost in dollars per MWh of providing an additional MWh from a synchronized unit." The changes also include methods for market sellers to submit sloped, stepped or block loaded incremental offers into PJM's Markets Gateway System.

The manual changes will go to the MRC for endorsement.

## Energy Scheduling Practices Revisions Endorsed

Members unanimously endorsed revisions to the Regional Transmission and Energy Scheduling Practices document.

Chris Pacella, PJM | © RTO Insider LLC

Chris Pacella, senior lead analyst in PJM's transmission service department, *provided* an overview of the *revisions*. Pacella said the revisions consisted of three main drivers, including minor clarifications related to process improvements in the 2019 OASIS Refresh project, minor updates as part of a general review, and updates related to the North American Energy Standards Board's Wholesale Electric Quadrant v3.2 Business Practice Standards that take effect Oct. 27.

The updates now go to the MRC for endorsement. ■

*— Michael Yoder*

| Event | Year | Hour Ending | THI | Plan | Resource | A<br>Line Loss | B<br>CBL (MW) | C<br>Metered Load (MW) | D<br>Total Participating MW | Shortfall MW (by Manual)* |
|---|---|---|---|---|---|---|---|---|---|---|
| E12020 | 2020 | 13 | 81.0 | P1 | 1234 | 1.03 | 5 | 4.993 | 0.1485 | 5.28429 |
| E12020 | 2020 | 14 | 81.0 | P1 | 1234 | 1.03 | 5 | 4.829 | 0.22275 | 5.02562 |
| E12020 | 2020 | 15 | 81.0 | P1 | 1234 | 1.03 | 5 | 4.653 | 0.29106 | 4.73665 |
| E12020 | 2020 | 16 | 81.0 | P1 | 1234 | 1.03 | 5 | 4.756 | 0.28809 | 4.94277 |

| Event | Year | Hour Ending | THI | Plan | Resource | A<br>Line Loss | B<br>CBL (MW) | C<br>Metered Load (MW) | D<br>Total Participating MW | Shortfall MW (Proposed) ** |
|---|---|---|---|---|---|---|---|---|---|---|
| E12020 | 2020 | 13 | 81.0 | P1 | 1234 | 1.03 | 5 | 4.993 | 0.1485 | 0.14129 |
| E12020 | 2020 | 14 | 81.0 | P1 | 1234 | 1.03 | 5 | 4.829 | 0.22275 | 0.04662 |
| E12020 | 2020 | 15 | 81.0 | P1 | 1234 | 1.03 | 5 | 4.653 | 0.29106 | 0 |
| E12020 | 2020 | 16 | 81.0 | P1 | 1234 | 1.03 | 5 | 4.756 | 0.28809 | 0.03677 |

Incorrect shortfall megawatt calculation results versus PJM's proposed calculation change with new results | *PJM*

## SPP News

# Co-op Accuses Xcel of Coal Plant Mismanagement, Deception

### *Comanche 3 has been Plagued by Outages*

*By Rich Heidorn Jr.*

A Colorado electric cooperative that is part owner of Public Service Company of Colorado's (PSCo) Comanche 3 coal plant sued the Xcel Energy subsidiary Sept. 7, saying the utility's mismanagement had cost it "tens of millions of dollars" in repair costs and purchases of replacement power.

Comanche 3, a 750-MW super-critical generator, has been plagued by repeated unplanned outages since it began commercial operation in 2010 and is now expected to be retired long before its expected 60-year lifespan.

*CORE Electric Cooperative*, which serves customers from Colorado's Eastern Plains to its Front Range, agreed to purchase a share of Comanche along with Holy Cross Electric Association, with PSCo owning a majority share and operating the plant.

But in a breach of contract *suit* filed in Denver County District Court, CORE said PSCo failed to properly maintain the plant, causing it be out of service an average of 91 days per year, only 27% planned, the "worst reliability record of any of PSCo's generation facilities."

The suit quotes from a March 2021 Colorado Public Utilities Commission *report* that concluded the reliability issues resulted from "poor maintenance practices" and "lack of thoroughness in procedures and training."

The suit says outages between 2010 and 2020 resulted from "boiler tube leaks and equipment replacements" resulting from PSCo's "imprudent utility practices and failure to maintain proper water chemistry."

The plant suffered a yearlong outage beginning in January 2020 when two turbine blades broke off while spinning at high speed, shutting the plant down for 141 days. When the utility attempted to restart the plant after repairs, technicians improperly shut of all lubrication to the turbines, causing another 231-day outage, CORE said.

"Without lubrication, metal-on-metal contact occurred between various components of Comanche 3's rotor train. According to the PUC staff report, 'observers noted sparks coming from some of the turbine bearings, and a flash fireball was seen coming from the top of the [turbine lubrication oil] tank,'" CORE said.

Under its agreement, CORE agreed to purchase replacement power from PSCo when Comanche 3 was out of service. The yearlong outage cost the co-op more than $38.5 million in replacement power — $20 million more than it would have paid from power from Comanche, it said. "PSCo enjoyed an unjust enrichment, at CORE's detriment, by receiving much higher payments for replacement power from CORE as a result of PSCo's failure to properly operate Comanche 3," the suit alleges.

The cooperative said it was unaware of PSCo's poor maintenance until recently because the utility intentionally withheld information from a joint committee, including CORE and Holy Cross, to oversee the plant.

CORE asked the court to force PSCo to pay damages and to relieve the cooperative from paying for any share of the costs of repairs or reconstruction.

Xcel spokeswoman Michelle Aguayo said the company is "still reviewing the documents and generally [doesn't] comment on pending lawsuits."

"That said, Xcel Energy remains committed to ensuring the safe, reliable operation of the plant through its proposed early retirement in 2040. Comanche 3 is one of the lowest-cost generating plants on our system and has proven valuable to the system over its life." ■


Xcel Energy's Comanche 3 coal plant | *KRDO*

## SPP News

# SPP: Consolidating Tx Planning Could Yield Big Savings

### *Staff Projects More Efficient Processes Will Cut $9M Annually*

*By Tom Kleckner*

SPP staff and stakeholders last week discussed high-level recommendations for consolidating the RTO's transmission planning processes, an initiative the RTO says could save $9 million annually by 2030 while also producing a more holistic view of its transmission needs.

"I think there's even more value to be gained from this," predicted SPP COO Lanny Nickell, who said a business case that "fleshes that out" is being developed.

"By consolidating the processes and trying to meet all the needs with single study process — whether it's new generation that want to be interconnected or load growth — we believe there's a lot of value to be gained by deriving the optimal transmission set ... in more equitable fashion than today," Nickell said.

During an education session Wednesday, Nickell told the Markets and Operations Policy Committee that SPP's current planning processes cost about $28.5 million annually, but that the new consolidated process is projected to cost $25.5 million during its first three years and $24.7 million in Year 4 and beyond. Savings are expected to reach up to $8.9 million by 2030.

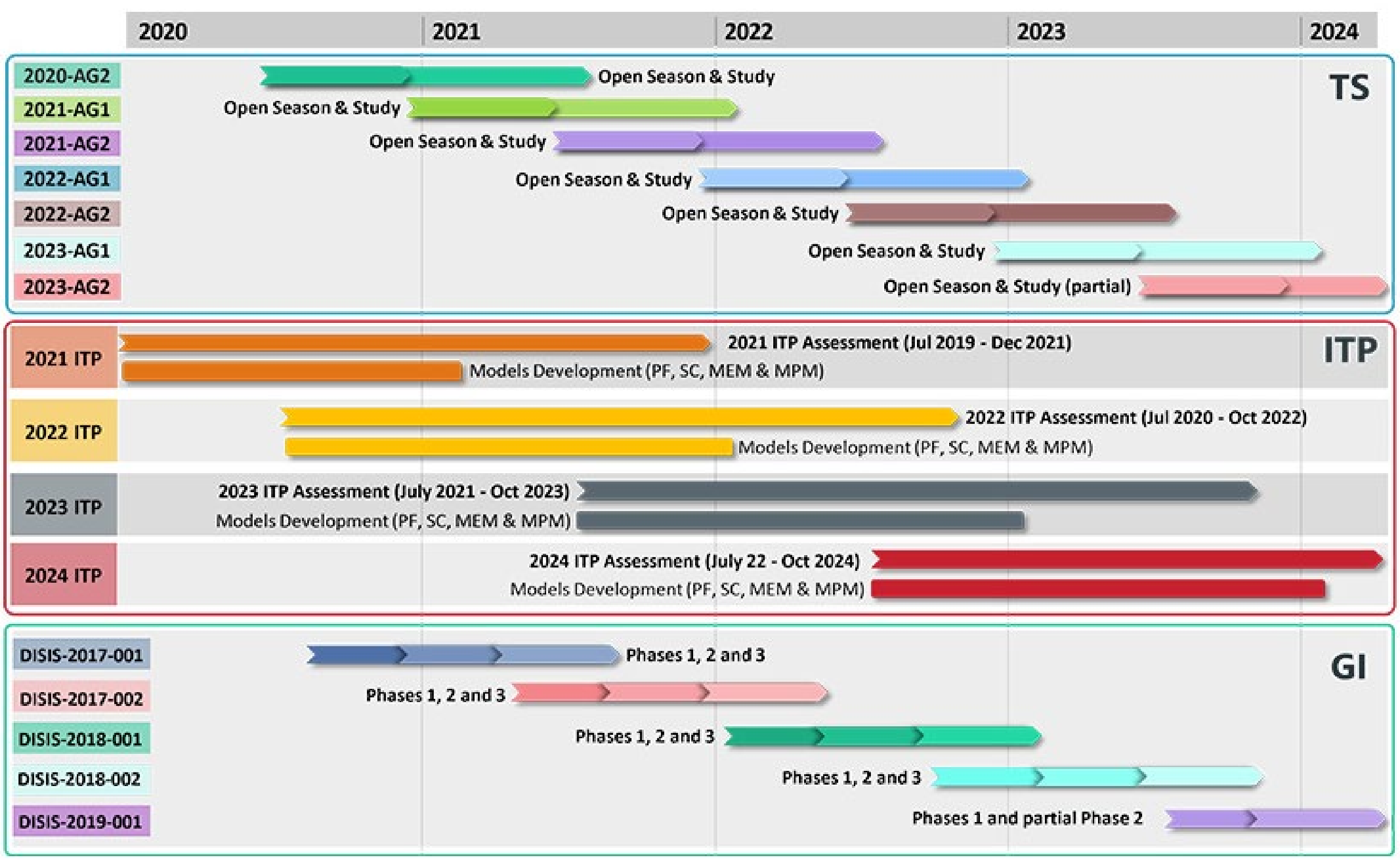
COO Lanny Nickell says consolidated planning process could result in $9 million in annual savings by 2030. | © *RTO Insider LLC*

"That's just staff savings, accrued as a result of improving the planning process' efficiency," Nickell said.

Staff currently spends more than 132,000 hours annually in the planning processes, a number that is projected to drop by nearly 14,000 hours with consolidation. Nickell said it will take two to three years and $7.5 million to implement the consolidated approach.

The Strategic Planning Committee last year created the Strategic and Creative Re-engineering of Integrated Planning Team (*SCRIPT*) to analyze the RTO's interconnected planning processes and applicable cost-allocation methods. (See "SPC Takes Look at Tx Planning," *SPP Briefs: Week of Aug. 31, 2020*.)

The SCRIPT created six sub-teams, comprised of its members and SPP staff, to focus on consolidation, services, optimization, decision quality, transfers and cost-sharing. They have produced 48 recommendations and sub-recommendations over more than 60 meetings and 11 months. The SCRIPT has provid-




Current timelines for SPP's transmission service, ITP and generator interconnection studies | *SPP*

## SPP News

ed feedback on the recommendations, which are under review and likely to change.

Nickell said the team is nearing the end of its policy development and plans to share its results and a final version of its *draft report* during the October governance meetings.

"We do have some work ahead of us," he said. "There's going be another group of recommendations that will enable more benefits from having a consolidated process."

The sub-team working toward an "appropriate consolidation" of SPP's Integrated Transmission Planning (ITP), generator-interconnection and transmission service studies, is central to SCRIPT's success. It recommended:

- creating a common base model set to meet regional planning needs required by SPP's Tariff and NERC reliability standards;
- modifying the high-priority study planning assessment requirements to provide additional scope flexibility and allowing it to be performed on an as-needed basis;
- expanding the model data systems used for collection and review, and developing automation and an intermediary database with links to existing regional planning tools to better correlate input data, processes and study outcomes; and
- staff and stakeholders work together to evaluate, approve and build out design- and implementation-level processes for one of the two consolidated options for customer optionality, cost-certainty of assigned upgrades, and regulatory planning compliance.

The team's two-phase approach involves first consolidating ITP, GI, transmission service, NERC transmission planning, and local planned transmission system changes processes. That would be followed by combining system load, sponsored upgrades, and generator retirement processes.

"We are going to be bound by NERC requirements to some degree. We're going to have to keep some studies on track," SPP's Kelsey Allen said.

Allen said staff is considering providing "fast-track" options to quickly connect resources. "We're hoping to be able to create a lot more efficiency in the processes than we have today, and that comes from the first consolidation," he said.

Antoine Lucas, SPP's engineering vice president, said his optimization sub-team recommendation that SPP develop a process to conduct holistic planning needs and solutions assessments complements the consolidation recommendations.

"It gives guidance on the approach and how to do that," he said. "This really is all about identifying the projects that provide the most value to the overall region, but that also bolster the reliability expectation we have."

Under the recommendation, staff would assess proposals for addressing market efficiency, public policy needs, and reliability issues for network load service and GI requests. Once the portfolio is established, staff could then conduct an impact analysis of GI requests and applicable transmission service requests impacts and use the results as a component of cost-sharing considerations.

"The fact [is we] don't know what's going to come out of the planning process. We do believe we can increase the value of transmission portfolios that are being recommended and approved," Nickell said.

The Generator Outage Task Force (GOTF) also briefed MOPC during the education session on its work to address outage-scheduling practices and concerns over how to reliably schedule outages given the changing resource mix.

The task force was created after SPP declared a Level 1 energy emergency alert and it called for conservative operations 10 times in 2019. The grid operator attributed six of the 10 operations events to generation outages.

The group is recommending a generation assessment process that includes a long-term horizon (five years) and a short-term view (the next seven days). The assessment's wind, demand, capacity and outage, and forced unscheduled outages will serve as inputs to determine the number of maintenance outages that can be taken without threatening reliability.

The GOTF is also urging SPP to change the outage/derate reporting threshold from 25 MW to 10 MW and to allow forced outages to have up to seven days of maximum lead time, so that they align with NERC's generating availability data system.

The recommendations will be finalized during the task force's next meeting Sept. 24. ■

# Company Briefs

## Energy Vault Reaches $1.6B SPAC Deal to Go Public

Energy Vault is combining with Novus Capital Corporation II to go public in a merger that values the gravity-based energy-storage company at roughly $1.6 billion, the companies said.

Energy Vault uses a block tower system to store and release renewable energy. Employing software to gauge when power demand is low, it uses surplus renewable energy to store power by constructing the tower with a crane. When demand rises, the crane unstacks the tower, producing kinetic energy by dropping the blocks so that they can turn generators and create electricity.

Energy Vault expects its first sales in 2022, then rapid growth as customers across industries demand clean energy.

More: *The Wall Street Journal*

## Iceland's 'Orca' to Capture $CO_2$ from the Air

The Orca, a facility in Iceland that will pull 4,000 metric tons of carbon dioxide out of the atmosphere per year, began operating last week.

The carbon capturing plant is the biggest of its kind and increases global capacity for the technology by more than 40%, according to developer Climeworks. Human-sized fans sit in a series of boxes that sip carbon dioxide out of the air, catching it in sponge-like filters. The filters are blasted with heat to free the gas. Then it is mixed with water and pumped deep into underground basalt caverns, where it eventually cools down and turns into dark-gray stone.

The IEA recently said humanity will need to pull nearly a billion metric tons of carbon dioxide from the atmosphere every year through direct air capture technology by 2050 to achieve carbon neutral goals.

More: *The Washington Post*

## NGA Selects New President

The Northeast Gas Association (NGA) has appointed Charles Crews as president and CEO; he took over on Sept. 1.

Crews has 25 years of leadership experience in the natural gas industry at multiple investor-owned natural gas distribution and transmission utilities. He worked for Consumers Energy from 2013 to 2019 in several positions, including vice president of gas operations.

Crews succeeds Thomas Kiley, who had served as NGA president for 36 years.

More: *Northeast Gas Association*

## Second North Central AEP Project Now Online

American Electric Power last week said the second of three wind farms comprising its $2 billion North Central Energy Facilities project has begun commercial operations.

The 287-MW Maverick Wind Energy Center in north central Oklahoma joins the 199-MW Sundance project, which went online in April. The 999-MW Traverse project, which is expected to begin operation early next year, will complete the initiative and provide 1,485 MW of renewable energy to customers of AEP's Public Service Company of Oklahoma and Southwestern Electric Power Company subsidiaries.

The project replaces AEP's $4.5 billion Wind Catcher Energy Connection, a proposed 2-GW wind farm and a 360-mile transmission connection that failed to gain regulatory approval. Arkansas and Oklahoma regulators signed off on North Central last year. (See *AEP a Go with $2B North Central Wind Project*.)

More: *AEP*

## Tesla Plans Energy Trading Team as it Expands Battery Projects

According to its website and other job posting sites, Tesla is looking to staff an energy trading team to support its battery and renewable power projects.

The company has expanded operations to include home solar and large battery storage facilities. It also recently applied to begin marketing electricity in Texas. Tesla plans to use an in-house automated trading platform, Autobidder, for "bidding batteries into multiple wholesale energy markets," according to the job description on its website.

More: *Reuters*

## Vistra's Moss Landing Facility Knocked Offline After Batteries Overheat

Vistra's Moss Landing Energy Storage Facility in California was forced offline on Sept. 4 when an unspecified number of batteries overheated.

Local fire crews were called around 8 p.m. to a reported structure fire, but no fire was found. Reports said that first responders discovered battery racks that had been scorched and wires melted. Vistra later said the facility experienced "an overheating issue with a limited number of battery modules" which affected the facility's Phase I 300 MW/1,200 MWh system.

Vistra said it would keep the entire facility offline as it investigates the root cause of the incident.

More: *pv magazine*

# Federal Briefs

## Appeals Court Rejects Request for Pipeline Reconsideration

The U.S. Court of Appeals for the D.C. Circuit last week declined to reconsider its June decision that said FERC improperly granted Spire Energy approval for its 65-mile gas Spire STL Pipeline in 2018.

The court said FERC "failed to consider evidence of self-dealing" by Spire in building the pipeline.

Following the denial, the company argued it's even more urgent that FERC grant it temporary approval to keep operating the pipeline to avoid "significant implications for the health and safety, property and economic prosperity of the St. Louis region."

More: *Missouri Independent*

## Dems Propose New Funding for Climate, Weather Research

Democratic members of the House Science, Space and Technology Committee are hoping to secure at least $2.6 billion in government funding for weather and climate change research at federal agencies.

The measures being proposed would devote $1.2 billion for NOAA programs, including forecasting events such as tornadoes, droughts, hurricanes and wildfires and better understanding the effects of climate change on the ocean. It also would put an additional $765 million toward NOAA research in climate adaptation and resilience.

At the EPA, the proposal would put $264 million toward climate-related research and development activities. At NASA, it would put $388 million toward similar programs. Other provisions would set aside about $1.2 billion for advancing nuclear fusion, while allocating $1.1 billion to demonstration projects for wind, solar, geothermal and water energy.

More: *The Hill*

### NARUC Nominees to Federal-State Electric Tx Task Force Appointed

The National Association of Regulatory Utility Commissioners (NARUC) last week announced that all the state commissioner nominees to the new Federal-State Electric Transmission Task Force were accepted by FERC. Maryland Public Service Commission Chair Jason Stanek was selected as vice chair.

FERC will hold five seats on the task force (one for each commissioner), along with 10 state commissions representing each NARUC region. They are Gladys Brown Dutrieuille (Pennsylvania), Andrew French (Kansas), Dan Scripps (Michigan), Riley Allen (Vermont), Matthew Nelson (Massachusetts), Kimberly Duffley (North Carolina), Ted Thomas (Arkansas), Kristine Raper (Idaho), Clifford Rechtschaffen (California) and Stanek.

More: *NARUC*

# State Briefs

## ARIZONA

### Coconino County Planning, Zoning Approves Wind Farm

The Coconino County Planning and Zoning Commission unanimously approved a 50-turbine wind farm and solar array northwest of Flagstaff.

Several commissioners said the decision was not an easy one; they were concerned about the impact the project might have on wildlife such as golden eagles and bats. In the end, the commission felt the issues could either be mitigated or that other priorities took precedence.

The project, which is being developed by NextEra Energy Resources and Babbitt Ranches, will seek additional approval from the county board of supervisors.

More: *Arizona Daily Sun*

## CALIFORNIA

### CEC, SoCalGas Settle Climate Lawsuit

Southern California Gas and the Energy Commission last week agreed to settle a lawsuit brought by the utility, which claimed state officials were ignoring a law that requires them to tout the benefits of natural gas.

SoCalGas agreed to drop the suit even though the commission didn't take the steps it demanded and has no plans to do so, Energy Commission Spokesperson Lindsay Buckley said. SoCalGas also did not say why it agreed to drop the lawsuit.

In 2013, lawmakers approved the Natural Gas Act, which required the commission to "identify strategies to maximize the benefits obtained from natural gas as an energy source" every four years.

More: *Los Angeles Times*

### Santa Ana Pledging Clean Energy by 2045

The Santa Ana City Council last week approved a sweeping resolution that committed the city to 100% clean and renewable energy usage by 2045.

The resolution includes a commitment to investigate and implement policies that limit or prevent the expansion fossil fuel use and support more open space to stem pollution. The city also committed to investigating the promotion of decarbonization and electrification of buildings and transportation.

More: *Daily Pilot*

### Sonoma Judge Rejects PG&E Bid to Narrow Kincade Fire Case

Sonoma County Judge Mark Urioste last week rejected an effort by Pacific Gas & Electric to gut Sonoma County prosecutors' criminal case against it for starting the 2019 Kincade wildfire.

Urioste denied the utility's procedural move to have 25 of the 33 criminal charges tossed out, which would have severely diminished District Attorney Jill Ravitch's case. PG&E is set to enter pleas on Oct. 13 to the five felony and 28 misdemeanor counts stemming from its alleged actions causing the fire.

PG&E didn't deny the facts of the case but asserted that 25 counts accusing it of emitting air contaminants were legally insufficient.

More: *The North Bay Business Journal*

### Storm Damage Tops $8 Million, IID Says

The Imperial Irrigation District (IID) last week said that two storms that hit the Imperial and Coachella valleys on Aug. 30-31 caused more than $8 million worth of damages to its system.

Between the two storms, IID lost more than 145 transmission and distribution poles.

More: *Holtville Tribune*

## ILLINOIS

### Judge: DeWitt Board 'Lacked Legal Authority' to Suspend Wind Permits

Sixth Judicial Circuit Court Judge Jason Bohm last week said the DeWitt County Board "lacked the legal authority" to stop the issuance of building permits for a county wind farm "because a county board has 'no power to suspend, even temporarily, their own ordinances.'"

On July 22, the county board voted to stop issuing building permits for the county's first wind farm until Alta Farms' parent company Enel Green Power complied with curtailing the turbines during severe weather. Alta Farms then filed a lawsuit against the county and Zoning Administrator Dee Dee Rentmeister demanding 15 building permits.

Rentmeister said 14 of the 15 permits were issued the same day Bohm rendered his decision.

More: *The Pantagraph*

# MISSOURI

## Ameren Seeks Rate Increase for Residential, Commercial Customers

Ameren Missouri last week filed a request with the Public Service Commission for a 12% rate increase.

According to Communications Executive Jenny Barth, the increase would fund upgrades to the electric and natural gas systems, as well support the utility's transition to cleaner energy.

If approved, the increase is expected to take effect by Feb. 28, 2022, and would add $11.78 to the average residential customer's bill.

More: *emissourian.com*

# MONTANA

## Judge Says Lawsuit Against NorthWestern Can Proceed

Missoula District Court Judge Jason Marks last week ruled that three residents and climate advocacy group 350Montana can proceed with their challenge to a 2003 law that guarantees NorthWestern Energy can recoup costs from planned power-producing assets.

In his order, Marks denied NorthWestern's motion, which had support from Attorney General Austin Knudsen and the Public Service Commission, to dismiss the lawsuit.

The issue is the constitutionality of the state's pre-approval statute, which allows a utility to pursue PSC approval of power-generating resources before the company has purchased or begun constructing them. Opponents say it insulates utilities from the financial repercussions of bad business decisions by keeping ratepayers on the hook for costly investments, even if they're ill-advised. The statute has come into focus in recent months following NorthWestern's announcement that it plans to build a 175-MW natural gas plant that's expected to cost more than $286 million.

More: *Montana Free Press*

# TEXAS

## State Bans Storage of Nuclear Waste

Gov. **Greg Abbott** last week signed a bill that attempts to block a plan to store highly radioactive nuclear waste at an Andrews County site proposed by Waste Control Specialists and Interim Storage Partners.

The legislation includes a ban on disposing of high-level radioactive waste in Texas, excluding the state's former nuclear power reactors and former nuclear research and test reactors on university campuses. The law will also bar state agencies from issuing construction, stormwater or pollution permits for facilities that are licensed to store high-level radioactive waste.

However, the new law may soon conflict with federal regulators, as the Nuclear Regulatory Commission is advancing the application for a license to allow the high-level nuclear waste site in Texas. A decision could come as early this week, an NRC spokesperson said. In July, NRC staff recommended that the site be approved to take the most dangerous type of nuclear waste.

More: *Texas Tribune*

# VIRGINIA

## Dominion Overcharged Customers by $1.2B since 2015, Expert Says

According to testimony filed by Heather Bailey, a Texas-based consultant and former utility executive and regulator, Dominion Energy has overcharged its customers by $1.2 billion since 2015.

The testimony, which was filed with the State Corporation Commission, was submitted by the environmental group Appalachian Voices. Dominion is expected to file a response in the coming weeks.

The commission can't order any refund of excess profits Dominion earned in 2015 or 2016 because of the 2018 Grid Transformation and Security Act. If the commission agrees to three accounting recommendations backed by the environmental groups, it could refund $372 million to customers; the commission would also have an option to adjust future rates.

More: *Richmond Times-Dispatch*

## Energix US Scraps Solar Farm Plans

Energix US last week announced it has scrapped plans to build a solar farm in Westlake.

In email to Franklin County, Yarden Golan, the company's director of public affairs, said that due to feedback from county officials and residents, the company is relocating the project to avoid the designated growth area where the proposed solar farm was to be located

Energix had announced plans to construct the 220-acre solar farm in April.

More: *The Roanoke Times*

# WEST VIRGINIA

## AEP Subsidiaries Ask Ratepayers to Pick Up Cost for Plant Upgrades

Appalachian Power and Wheeling Power last week petitioned the Public Service Commission to approve making customers responsible for $48 million annually to cover wastewater compliance work to keep the John Amos, Mountaineer and Mitchell coal-fired generating plants federally compliant.

The companies are asking West Virginia customers to shoulder the costs for the upgrades because Kentucky and Virginia regulators denied the companies' requests. Not making the wastewater treatment upgrades would require the plants shutter in 2028, per EPA rules.

If all treatment work is performed and recovered from only West Virginia customers, a 3.3% increase that would start in Sept. 2022, Appalachian Power spokesman Phil Moye said.

More: *Charleston Gazette-Mail*

# WISCONSIN

## MGE to Reduce Flat Charges as Part of Settlement

Madison Gas and Electric last week agreed to reduce the flat monthly fees charged to all electricity customers.

Under the agreement, which is subject to approval by the Public Service Commission, the average residential customer would pay about $4.10 more per month for electricity in 2022 with no increase the following year. That's slightly less than the original 5.9% rate hike MGE requested. Residential natural gas customers would see average increases of $12.24 in 2022 and $2.76 the following year.

It will bring MGE's fixed charge in line with Alliant Energy's, which is the lowest among the state's largest for-profit utilities.

More: *Wisconsin State Journal*

## PSC Approves Dodge County Solar Farm

The Public Service Commission last week voted unanimously to authorize construction of the 100-MW Springfield Solar Farm.

The 600-acre project is being developed by National Grid Renewables for Alliant Energy, which is seeking permission to buy the plant for $124 million as part of a plan to add nearly 1,100 MW of solar to its portfolio.

More: *Wisconsin State Journal*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