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COVER: FERC staff present the commission's order approving two new NERC reliability standards to commissioners at their open meeting Feb. 16 in D.C. | *FERC*

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NARUC Winter Policy Summit

NARUC Panel Tackles Gas-Electric Coordination

Despite Repeated Winter Events, There's Still Work Left to Do

By James Downing

WASHINGTON — Despite making progress after repeated high-profile winter reliability events, the gas and electric industries still have more work to do to coordinate their operations enough to avoid such incidents in the future, experts said at the National Association of Regulatory Utility Commissioners' Winter Policy Summit on Feb. 13.

Winter Storm Uri in February 2021 and Winter Storm Elliot in December 2022 each presented the power and gas sectors with a different set of problems, according to MISO President and COO Clair Moeller.

But Moeller said the events shared a common thread: Those problems were rooted in a continued disconnect between the industries — one stemming from difference in how they operate.

"Electricity is 'N minus one' forever," he said, referring to the power industry's "N-1" reliability criterion, which holds that the grid must be equipped in a way that it can lose a major resource or transmission line without threatening electricity supply. "Gas is like, 'You know, pipes don't fail very often, so maybe it's not worth those investments.'"

The gas industry has been more focused on the commodity itself rather than ensuring resilient operations because nobody has paid it to provide the latter, he said.

"Just to make it more fun in the planning horizon, we're asking them to become intermittent resources, the reciprocal of renewables, to fill all those holes, and at the same time, we're electrifying, taking their base load," Moeller said. "So, the planning problem here is enormous."

The differing business models makes it difficult to figure out whom to talk to in order to bridge the differences between the two industries, Moeller said. And even within the gas industry, the pipelines have their own issues, which are different from the local delivery companies and natural gas suppliers.

"There really isn't a very good place to talk about it except here, which is why I bring it up," Moeller said. "It's time; the penetration of renewables is accelerating. We're relying on gas to be that reciprocal intermittency. But we haven't told them what that looks like, and we haven't shown up with a checkbook to make sure that they can do it."

Panelists discuss electric-gas coordination at NARUC's Winter Policy Summit on Feb 13. From left: Kentucky PSC Chair Kent Chandler, Indiana Utility Regulatory Commission Chair Jim Huston, AGA Chief Regulatory Counsel for Energy Matthew Agen, PJM Senior VP of Operations Michael Bryson, NRG Executive Vice President Chris Moser, MISO COO Clair Moeller and Texas PUC Commissioner Lori Cobos. | © *RTO Insider LLC*

After experiencing the polar vortex of 2014 and helping its neighbors get through Uri, PJM Senior Vice President of Operations Michael Bryson said he thought his RTO had achieved good coordination with the gas industry.

"I think we found out during Elliot that there were certainly gaps in what we were able to see in terms of availability," Bryson said.

PJM's load forecast was off by about 10% as it was not ready for the rapid temperature drop over the Christmas holiday weekend, but it also ran into plenty of outages of gas-fired plants that its operators were unaware of until they tried to dispatch the units, he added.

"We actually had, in fact, during Elliot, what I would consider the golden ticket of capacity performance gas: firm transportation, firm supply, no notice scheduling," Bryson said. "We had units with that, that were curtailed."

PJM does not have visibility into the operational issues natural gas suppliers might be running into during extreme weather, and that could be fixed by requiring similar information sharing between the gas and electric industries as the RTO does with its neighboring grid operators, he said.

Post-Uri Reforms in ERCOT

Texas has been working on reforms to its power market since Uri knocked out about 50,000 MW of its generation, plunging the state into blackouts that lasted for five days and causing hundreds of deaths and billions of dollars in damages. They include mandatory winterization standards that can be enforced with fines of $1 million per violation per day, said Texas Public Utility Commissioner Lori Cobos.

"We've also developed a first-in-class, first-in-the-country new firm fuel product to help ensure winter resiliency when fuel availability issues arise," Cobos added.

The PUC authorized ERCOT to procure up to 3,000 MW for the new firm fuel product, and it signed up 19 power plants, 18 of which can burn fuel oil with storage onsite, while the other has a direct pipeline connection to its own natural gas storage facility. All the generators can provide power for up to 48 hours.

ERCOT used the firm fuel product for the first time during Winter Storm Elliot just before Christmas, calling up eight generators that supplied 950 MW, Cobos said.

While the product provided some guaranteed generation, the PUC still is looking into the 13,000 MW of generation that went offline during Elliot, specifically whether any had weatherization issues, she said.

Gas-fired generation has grown at the expense of coal because it is cleaner, but it cannot be stored. And now the electric industry is relying on the gas industry to meet needs the gas system was never designed for, said Chris Moser, head of competitive markets and policy at NRG Energy.

"The gas system itself is well-built; the electric system itself is well-built. The combination of those two systems, frankly, is brittle," Moser said. "And it's the touchpoints in between the two of them, some of them just on a daily basis, where things start to break down."

The issues are exacerbated during winter storms, when spot prices for natural gas spike to above $100/MMBtu, which leads to generator bids above the price cap in many markets. Uri saw prices reach $1,200/MMBtu on the border of Texas and Oklahoma despite the region's vast supplies of natural gas, said Moser.

When gas is just $4 or even $10/MMBtu, generators can deal with it, but once prices get into the hundreds that can "sink an entire company," Moser said. ■

Making the Case for Nuclear at NARUC

As Vogtle Reactors Prepare to Go Online 6 Years Late, TVA Plans for 20 SMRs

By K Kaufmann

The Vogtle nuclear plant near Waynesboro, Ga. The original units, Vogtle 1 and 2, are in the background. The new units, 3 and 4, are in the foreground. | *Georgia Power Company*

WASHINGTON — The Tennessee Valley Authority has set its sights on 80% carbon-free generation by 2035 and a net-zero system by 2050, with plans to develop a fleet of up to 20 small modular nuclear reactors to meet the utility's need for increasing amounts of secure, decarbonized electricity, according to CEO Jeff Lyash.

"I have no interest in building one reactor," Lyash said during a session on nuclear development at the National Association of Regulatory Utility Commissioners' Winter Policy Summit on Feb. 12. "In order for us to be successful, TVA needs something on the order of 20 reactors over that period of time. So, if you can't see your way to reaching nth-of-a-kind costs, supply chain, workforce, project execution for a portfolio of reactors, I don't see the point in building one."

Approved by the TVA board in February 2022, the federally owned utility aims to build its first SMR at its Clinch River location in Tennessee, which now has an *early site permit* from the Nuclear Regulatory Commission. Separate from a construction permit, this permission provides safety, environmental impact and emergency preparedness approvals for a site where one or more nuclear plants may be built.

TVA will still need a construction permit for the 300-MW GE Hitachi BWRX-300 SMR it is now considering for potential deployment at Clinch River. The utility's goal is not only to show that the technology works, Lyash said, but that it can be deployed "in a way where you can demonstrate the ability to build enough reactors to materially affect the outcome we're looking for, which is energy security, decarbonization in the face of electrification and economic growth."

The rising profile of nuclear power as one of the critical technologies that will power the U.S. to a carbon-free grid was a major theme at the NARUC conference, with Lyash's session followed on Feb. 13 by an interview with Nuclear Regulatory Commissioner David Wright.

Introducing Wright, who is also a past president of NARUC, Tricia Pridemore, chair of the Georgia Public Service Commission, announced the formation of a new *Advanced Nuclear State Collaborative*, which will bring together members of NARUC and the National Association of State Energy Officials. The Department of Energy is sponsoring the initiative, which will provide technical assistance and expertise for states deploying or considering new nuclear projects, Pridemore said.

The initiative is one answer to the growing interest in nuclear across the country. In at least 20 states, "public service commissions and state energy offices are engaged in feasibility studies for advanced nuclear reactor site selection, strategies to reduce regulatory and policy barriers to new nuclear, and other activities to pave the way for advanced reactors," she said.

Wright also sees possibilities for the NRC to develop more active relationships with state commissions and policy makers. "There are things [utility commissions] are going to be involved in that need our expertise or maybe even just information," he told Pridemore.

"There are things you're going to want to do, and you're going to want to know — 'Can I do that?' he said. "Do we have to put certain regulations in place on the state level, or does the legislature have to do certain things?'"

But a bigger question looms for the U.S. nuclear industry and its supporters, including TVA and DOE, which is pouring billions into the development of advanced reactors: Can they adequately de-risk a technology known for massive cost overruns and project delays to build the trust of financial markets and the public at large — and how fast can they do it?

The Value of Vogtle

The two units nearing completion at the Alvin W. Vogtle Electric Generating Plant near Waynesboro, Ga., are a case in point. Vogtle's two existing reactors have been operating since the late 1980s, but the plant's next-generation expansion has become the poster project for cost overruns and delays, with Georgia's ratepayers picking up the tab with higher electric bills to finance construction.

The first new nuclear generation built in the U.S. in 30 years, the project is now six years behind schedule, and its original cost estimate of $14 billion has ballooned to more than $30 billion. Vogtle has also received $12 billion in loan guarantees from the Department of Energy's Loan Programs Office (LPO), made during both the Obama and Trump administrations.

The first new unit at Vogtle is now expected to

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come online in May or June, a delay from the previous target of the end of April, Georgia Power *said* Thursday. The second unit is scheduled to begin commercial operation between this November and March 2024. Georgia Power also wrote off $201 million in additional costs for the reactors, reflecting increased costs. Together, the two units will provide 1,250 MW of power.

With completion almost in sight, the industry narrative on the troubled project is focused on its upside and long-term benefits.

Joining Lyash, LPO Director Jigar Shah said that Vogtle shows that "America is deciding to do big things. …

"We had to train 13,000 men and women, who were all union, to build those projects, and we now have that trained workforce, and many of those folks paid off debt for their entire families," Shah said. "I think the transformational nature of what Vogtle did is something that we should celebrate, celebrating the persistence, the spirit of nuclear to get that done."

That persistence also paid off in Poland's recent decision to choose the same Westinghouse AP1000 reactors soon to go online at Vogtle for its first nuclear project, Shah said.

Similarly, Lyash sees Vogtle as a first-of-its-kind project that has produced valuable lessons learned. "The key is to have the fortitude and the confidence to harvest those learnings and integrate them and to use [them] to benefit the nation," he said.

"And those lessons are around project management and execution, risk management, what a supply chain looks like, what the workforce needs to look like," he said. "Vogtle has helped build the end capabilities now that I'll be taking advantage of if we move forward with the BWRX-300."

Despite Vogtle's problems, Lyash predicted that "a decade from now, you're going to be very, very happy that you have those facilities. They're going to be impacting the economy and the environment, and they have generated a design that is beginning to be deployed around the world."

Shah said, even today, the LPO would provide the same loan guarantees to the project. A key point for such decisions is whether the office sees "a realistic prospect of repayment," and he expects Vogtle will fully repay its loans.

'A Fragile System'

The positive momentum for nuclear at NARUC notwithstanding, opinions nationwide about moving forward with new plants remains divided. In its most recent *poll* on the issue, Gallup found support for nuclear edging up to 51% versus 47% opposed, a slight shift from 2019, when the country was evenly split, 49% to 49%.

Nuclear Regulatory Commissioner David Wright and Georgia Public Service Commission Chair Tricia Pridemore | © RTO Insider LLC

A *Pew Research poll* taken before Russia's invasion of Ukraine last year found that 35% of those surveyed said the U.S. government should support nuclear; 25% said the government should not support it; while 37% were neutral on the issue.

Opinions also differ on the cost of maintaining the country's existing 92 nuclear reactors, which provide about 20% of the nation's power and 50% of its carbon-free electricity.

At the Feb. 12 session, Commissioner John B. Howard of the New York Public Service Commission raised the issue of state subsidies for existing plants, such as New York's zero-emission credits (ZECs) "that many believe are not affordable and sustainable."

Nuclear power development has gotten too expensive, Howard said.

A *recent NARUC report* on the U.S. nuclear market lists New York, Illinois, Connecticut, New Jersey and Ohio as providing ZECs for their existing plants. The Infrastructure Investment and Jobs Act also provides $6 billion in funding for a Civil Nuclear Credit Program to help plants stay open.

But Lyash countered that nuclear plants are "highly competitive."

According to the NARUC report, more than two-thirds of the clean power supply in 20 states comes from nuclear, and in Mississippi, nuclear accounts for 96% of the state's carbon-free power.

Nuclear is 42% of TVA's power supply, Lyash said, and he expects that percentage to hold steady even as the utility's electricity demand increases with economic growth and electrification of buildings and transportation.

Nuclear plants are "high capital on the front end, but they have a tremendously long and beneficial life," he said. "They also deliver all the attributes to a power system that you need — voltage, frequency, maneuverability."

Echoing a familiar nuclear industry argument, Lyash said ZECs should not be seen as subsidies, but rather as paying nuclear plants "for the value that they already delivered because markets have a difficult time recognizing that."

Shah framed the case for nuclear in terms of system reliability. "We have a fragile system, and that fragility has come from [independent power producer]-run natural gas plants," he said. "For the last three years, we have seen

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a historic amount of failure out of those gas plants. … For many people, nuclear power represents a better form of baseload clean power to be able to provide that to people long term, [but] what they are afraid of is that we haven't figured out how to build them on time, on budget."

TVA's Clinch River project could be the next step toward that goal, he said.

Lyash countered that the issue was not system fragility, per se, but the rising expectations of customers who are themselves increasingly dependent on electricity. "If you roll back 75 years, only about 2% of all the end-use energy in this country came from electricity; today it is 22%, and by 2050, it's probably going to be 50%," he said.

"The level of reliability on the U.S. electric system hasn't generally degraded," Lyash said. "The customer expectations have risen, and not just day-in, day-out reliability … but resiliency — how does it perform when it's [confronted] with the thing you hoped would never happen or happens infrequently," such as December's Winter Storm Elliott.

"People's expectations are entirely different. … Twenty years ago if your lights went out for 20 minutes, or flickered, you would not have cared," he said. "Today you really care about this."

From left: Georgia Public Service Commissioner Tim Echols; Jigar Shah, director of DOE's Loan Program Office; and TVA CEO Jeff Lyash | © *RTO Insider LLC*

'No Shortcuts'

Lyash also sees SMRs, like the BWRX-300, as easier to integrate on the grid. Smaller reactors could be strategically sited to ease transmission congestion, and in the event of an emergency, taking 300 MW offline would be less disruptive to system reliability than bigger units, he said.

Lyash, Shah and Wright are expecting nuclear development in the coming years to be centered on or near closed coal-fired plants with existing transmission, circumventing the need for extensive new transmission construction.

Shah pointed to a recent *DOE study* that identified 157 closed coal plants and an additional 237 coal plants still in operation as potential sites for coal-to-nuclear transition. The study also found 80% of those sites well suited for the development of advanced reactors of less than 1 GW.

For example, TerraPower's 345-MW Natrium reactor, one of two projects being developed under DOE's *Advanced Reactor Demonstration Program*, is being planned for Kemmerer, Wyo., where a PacifiCorp coal-fired plant is scheduled for retirement in 2025. The DOE program has $2.5 billion in funding from the Infrastructure Investment and Jobs Act and is supporting the development of two advanced reactors that are scheduled to be online by 2027.

The second reactor, X-energy's Xe-100, is being planned for a site in Washington state near an existing nuclear plant.

Wright sees these demonstrations and other coal-to-nuclear projects as the "low-hanging fruit" of the next wave of nuclear development. Siting a nuclear project on or near a closed or existing coal or nuclear plant could streamline permitting because "they've already got an [environmental impact statement]," he said. "We don't want to have to do an [analysis] if they're going on a site that's already been done. …

"There may be some tweaking to some regulations and rules we have to do in order to get ready, but we don't want to be the reason that they delay [or] they don't even get to market," he said.

NRC is also staffing up in preparation for what it expects to be an increasing number of projects applying for approval, Wright said. "We're onboarding 400 this year," he said.

While planning for an aggressive nuclear buildout, Lyash said TVA wants to pursue a diversified portfolio of clean energy resources that balances energy security, affordability and decarbonization. "No one resource can satisfy" these goals, he said. "You have to think about this not as a choice between wind or solar or nuclear or hydro or storage. It's the combination of all the right technologies in a portfolio that delivers energy security and [clean] energy to drive the economy."

Shah agreed, saying all resources should be on the table. The enthusiasm for nuclear at NARUC is part of the growing interest in other technologies, such as enhanced geothermal and low-impact hydropower, he said. Going forward, he sees industry enthusiasm and support for "all of the tools that have reached the level of maturity so they can rise to the occasion" of decarbonizing the U.S. economy.

But Shah said the greatest challenge ahead for nuclear may be building trust. "I think the nuclear industry, for better or for worse, was dormant for the better part of 30 years, not really pursuing innovation for the better part of 30 years," he said. Now the industry is developing SMRs and other innovative advanced reactors, but "they have to do a proper job. They have to learn all the lessons. They've got to make sure they measure 34 times and cut once.

"There's no shortcut to building trust," Shah said. "It's about doing these things in a highly competent fashion, making sure there is transparency, that we're fully admitting all the mistakes that were made in the past and learning from them." ■

NARUC Winter Policy Summit

NARUC Panelists: Rate Design Key for the Clean Energy Transition

By James Downing

Getting rate design right is important to the clean energy transition because it will help determine the best resource mix and ensure customers have opportunities to cut their bills with demand response and distributed resources, experts said at the National Association of Regulatory Utility Commissioners' Winter Policy Summit last week.

"The reason that I think there's no more exciting topic than rate design is because it truly sits at that intersection of every other aspect of the energy system: affordability, reliability; all of the conversations we're having around grid modernization, integration of different resources, customer choice," said former Virginia State Corporation Commissioner Angela Navarro, now head of state regulatory affairs for Richmond-based climate technology company Arcadia. "All of those things are central to determinations on rates."

Smart meters are on most homes in the country now, while rooftop solar and electric vehicles are becoming increasingly common; how those resources impact rates is very important, Navarro said. Storage has huge potential, but that can only be harnessed with the right rate design that informs its owners when to charge and discharge.

On the other side, the right rate design can help avoid negative impacts on the grid, such as by encouraging customers to charge their EVs during off-peak hours, she added.

Supply is going to be more variable in the future because of the growth of intermittent renewables and more common extreme weather, said Lon Huber, Duke Energy vice president of pricing and customer solutions.

"But fortunately, with technology, we have an increasing number of tools to use to start shaping load to match the more variable supply out there," Huber said.

Sending those price signals far and wide requires approval from regulators and the right technology; it cannot happen overnight, he added. On top of smart meters, utilities need field area networks, data management systems and updated billing systems that can take years to put in place.

Smart meters have been rolled out to 75% of the nation's customers and despite being in

Panelists discuss making the grid smarter through rate design at NARUC Winter Policy Summit on Feb. 13. From left: Washington Utilities and Transportation Commissioner Ann Rendahl; Arcadia Head of State Regulatory Affairs Angela Navarro; Duke Energy Senior Vice President of Pricing and Customer Solutions Lon Huber; NRG Vice President of Regulatory Affairs Travis Kavulla; and Delaware Public Advocate Andrew Slater | *© RTO Insider LLC*

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place for years in many jurisdictions, their use rarely matches their potential, said Travis Kavulla, NRG Energy vice president of regulatory affairs.

"We're still talking about single-digit percentages of those smart meters that are used to do anything to actually interact with customers in terms of sending a price signal or any other incentive to flex demand," Kavulla said.

Kavulla recently wrote a paper for an Energy Systems Integration Group effort looking into how retail pricing could be used to get customers to respond to grid needs, called "*Why is the Smart Grid So Dumb? Missing Incentives in Regulatory Policy for an Active Demand Side in the Electricity Sector*." It has been a more than a decade since federal stimulus dollars gave most states the push to install advanced metering, and despite soaring rhetoric from that time, the investment has done little to make demand an active part of the electric industry, he argues.

"My basic proposition is this: that someone somewhere has to face the clear price incentives to accurately manage demand in order for it to happen," Kavulla said. "And all too often in our regulatory schema that we set up for ourselves, regulated utilities themselves lack clear incentives to do so. And even for competitive retailers like NRG, we face an incomplete set of incentives to make these kinds of investments in demand flexibility."

Getting the rate signals right could mean huge savings, with New York state estimating it could cut the cost of compliance with its climate mandates by a third, while PJM identified retail rate design as one of five key focus areas for successfully decarbonizing the grid, he added.

Kavulla would like to see more jurisdictions set up opt-out time-of-use pricing to tap the demand resources that advanced metering has made available. Customer adoption of complex rates under opt-in constructs are too low.

"As much as my inner libertarian would like to avoid this, regulators really cannot escape making solid decisions on behalf of customers in highly regulated industries like these," Kavulla said.

Opt-in regimes usually produce better responses from customers who affirmatively decide to participate, said Huber. The system works too, with Huber noting Arizona has seen up to 60% participation in time-of-use rate programs.

"I think opt-in in the long run is better, but it takes time," Huber said. "And it takes a lot of marketing [and] a lot of education to get it done."

The Future of Solar

Getting rate design right is important for the solar industry as rooftop panels become increasingly common in many jurisdictions, leading to often thorny debates about how to pay for their excess output going forward, experts said an earlier panel on Feb. 12.

"Increasingly some of the issues that we're beginning to tackle are how do we sort of evolve the industry from what has been a traditional approach to behind the meter resources," Solar Energy Industries Association Senior Director of Utility Regulation and Policy Kevin Lucas said. "And how do we evolve that in a way that's going to make sure that regulators, policymakers, customers and utilities are getting the most bang for the buck out of the resources that they're putting onto the grid?"

SEIA is working in Arizona now to get a system in place that encourages more growth of solar-plus-storage than its current "net billing" structure, which does favor storage but incentivizes its use to shave the customer's own peak rather than the system peak. Customers get paid less for exporting power to the grid than they do shaving their own demand.

SEIA would like to see batteries controlled by utilities in a program where they can be called on up to 30 times a year for up to three hours at a time and they get paid based on response to those signals.

"So, if a customer chooses to participate in a given event, they will export energy, that energy is going to be measured, and at the end of the year, they will get a credit based on how well they perform during these specific calls," Lucas said.

Some 760,000 customers have solar installations on their homes, but just 47,000 customers around the country have adopted storage, said Sunrun Senior Manager for Public Policy Thad Culley. Most of the customers with storage have bought systems to improve their resilience because they live in areas that experience outages more often.

Expanding that market to a bigger number of customers and getting them to work with the grid is going to take some new rates, Culley said.

"You're going to need to have some kind of predictable value stream going forward to motivate the customer to want to play nice with the grid and do the types of grid support services that are valuable," Culley said.

With the right incentives, those customers could even provide more specific services that benefit the local grid, he added. ■

How to Quicken Transmission Development Discussed at NARUC

By James Downing

The U.S. used to be able to build massive infrastructure projects such as the Empire State Building and the Pentagon in just a year, but nearly a century later that is far from the case with electric transmission, Maryland Public Service Commission Chairman Jason Stanek said at the National Association of Regulatory Utility Commissioners' Winter Policy Summit on Feb. 13.

With billions in dollars in new federal incentives aimed at expanding clean energy, the pace of transmission development needs to speed up in order to take full advantage of those.

"As a state commissioner, I'm disappointed," Stanek said. "I'm disappointed that over my five years at the commission, I haven't been able to site and build 1 inch of interstate transmission."

The Inflation Reduction Act and the Infrastructure Investment and Jobs Act (IIJA) are setting the country on course for the largest investment in infrastructure installation in 100 years, said Jeff Dennis, deputy director of the U.S. Department of Energy's Grid Deployment Office.

"But we know that a significant portion of those benefits — as much as 80%, according to a Princeton study — of the emission reduction benefits that Congress expected from the IRA won't happen if we don't increase the pace at which we build transmission," Dennis said.

The past decade has seen the grid expand at a clip of about 1% per year, but that needs to exceed 2% to meet those goals, he added.

Much of the funding DOE received for transmission in those recent laws is for "commercial support" rather than the loans it has used most often in the past, said Dennis. The money will help finance and speed up the development of transmission.

The IIJA included $2.5 billion the department can use to facilitate transmission by doing things like becoming the anchor-customer on a line to help it get financed and then sell off that space as the project is developed. The IRA has another $2 billion that DOE can use to help support transmission projects deemed in the national interest, Dennis said.

DOE also has new loan authorities, including some aimed at repowering existing corridors so that they can transmit more energy than they do now, Dennis said.

The IRA offers $100 million for addition regional and interregional transmission lines.

New England is expecting major changes to its grid, as it will have to greatly expand clean energy to meet future demand, which is on pace itself to grow from 25 GW today to 43 GW in the future because of electrification, said Digaunto Chatterjee, vice president of system planning for Eversource Energy.

"The best way to deploy IIJA funds is to surgically address specific transmission upgrades on your system and create new landing sites for offshore wind," Chatterjee said.

While the industry has a daunting task of expanding its transmission grid and turning over to new sources of generation, it is a job that it has successfully performed in the past, said National Grid Clean Energy Development Director Terron Hill.

"When you think about the 1970s, we had a huge buildout of the transmission network in order to pick up electrification needs and new industries," said Hill. "We saw the same type of buildout of the transmission network as we transitioned away from oil and coal to natural gas."

New England has added about 300 MW of renewable energy per year, but to meet its carbon-mitigation goals, the pace of infrastructure development will need to be closer to 3,000 MW, Hill said.

"That is a huge challenge, but it's a challenge that we can meet," Hill said. "I was told very early in my career, that if you give engineers and planners a problem to solve, they will come up with the best solutions."

Part of the solution is getting more efficiency out of the existing transmission grid through the adoption of dynamic line ratings, topology optimization and advanced power flow controls, said Hilary Pearson, vice president of policy for LineVision. The firm's technology has helped New York wring more transfer capability out of its grid, which has historically been congested in power flowing from west to east and north to south, limiting the amount of load served by clean energy.

"By using dynamic line rating sensors in the western part of the state — very renewable-rich but has constraints and congestion on the system — we're going to be able to eliminate 320 MW of existing wind energy curtailments, while creating another 190 MW in headroom for new renewable energy projects to be able to come onto the grid," she said. ■

Panelists discuss expanding the transmission grid at NARUC's Winter Winter Policy Summit on Feb 13. From left: National Grid Director of Clean Energy Development Terron Hill; DOE Grid Deployment Office Deputy Director Jeff Dennis; Maryland PSC Chairman Jason Stanek; Eversource Vice President of System Planning Digaunto Chatterjee; and LineVision Vice President of Policy Hilary Pearson | © *RTO Insider LLC*

NARUC Winter Policy Summit

NARUC Panel Calls for Clean Energy, GHG Emissions Tracking Standards

Federal, State and Corporate Energy Buyers Use Different, Often Confusing Tracking Methods

By K Kaufmann

WASHINGTON — President Biden wants all federal agencies to use 100% carbon-free electricity (CFE) — 50% of which will be matched hour for hour 24/7 — by 2030. Rhode Island's Renewable Energy Standard will require the state's retail electricity suppliers to ensure that 100% of the power they provide is from renewable sources by 2033. And Google is targeting 100% clean energy, matched hour for hour 24/7, by 2030.

Despite their very different goals, these clean energy buyers all face a common challenge: figuring out how to keep track of both the clean energy they use and the carbon emissions they cut, according to a Feb. 13 panel discussion at the National Association of Regulatory Utility Commissioners' Winter Policy Summit.

"The way we account [for] CFE — in fact, the way the industry generally counts CFE — is not actually aligned with the way greenhouse gas emissions are counted for Scope 2 emissions," said Tanuj Deora, director of clean energy at the White House Council on Environmental Quality.

Scope 2 emissions are the greenhouse gas emissions generated by the electric power purchased by an organization. Scope 1 are the emissions an organization directly owns or controls, while Scope 3 are the emissions produced from sources an organization neither owns or controls, such as from companies in its supply chain.

"One could take actions that result in a 100% CFE score but [with] some emissions being … assigned to the user," Deora said. "On the other hand, we could actually zero out our Scope 2 greenhouse gas emissions but not actually be consuming only carbon-free electricity."

Moderating the session, Rhode Island Public Utilities Commissioner Abigail Anthony framed the panel as the beginning of a discussion on the need for "harmonized certificate tracking and emissions accounting systems" for clean energy and emissions reductions. States with and even without renewable or clean energy mandates are affected, Anthony said, as whether or not they have a legal obligation, businesses in a state may have their own clean energy targets.

"I want all my regulator colleagues to understand their role as a market regulator of ... generation certificates," she said. "This is not a conversation we sit on the sidelines of. … Some states are going to need to be able to defend their own claims of emission reductions, and then you need to have systems that allow us to defend those claims legally," as will corporations doing business in those states.

At the NARUC Winter Policy Summit, Rhode Island Public Utilities Commissioner Abigail Anthony (left) leads a discussion on the challenges of accounting for clean energy and greenhouse gas emissions, with (from left) Todd Bianco, Rhode Island PUC; Betsy Beck, Google; and Tanuj Deora, White House Council on Environmental Quality. | © *RTO Insider LLC*

While not calling on NARUC for an official working group on the issue, Anthony would like to see the organization provide "another space for us to work together to develop standards that would allow the determination of who has what and will allow new products to be developed more easily to enable more complex emission accounting."

She pointed to PJM's recent announcement of its new clean energy tracking service that will provide certificates broken down by the hour as an example of the level of detail and innovation that will be needed. (See related story, *PJM EIS Announces New Hourly Clean Energy Certificates*.)

"It's really important for us to figure out how to reconcile" these issues, Deora agreed. With more than 300,000 federal buildings across the U.S., the federal government is the country's largest energy consumer, with a load of about 54 TWh of electricity a year, he said. Producing that much clean energy, at least half of it 24/7, will require accounting standards that are "going to be inclusive of both the statutory requirements across all the states who have their own rules, as well as each individual buyer's specific targets and goals," he said.

Betsy Beck, who leads global energy markets and policy for Google, said the company has been procuring enough clean power and retiring the associated renewable energy credits to cover its global operations. But, Beck said, developing accounting standards for its 24/7 goals means "you need to think about the grid at a more granular level."

"It's not enough to just balance at a high level," Beck said. "Now we really need to be thinking about what are the right sources we need to fully decarbonize the grid. It can't just be building the cheapest renewable energy sources, which have been wind and solar, but what do we need for the carbon-free energy supply in all hours of all days so that we do not need

NARUC Winter Policy Summit

other fossil resources kind of backing renewables up?"

Who Has the Carbon Emissions?

As a member of NEPOOL, Rhode Island uses a relatively straightforward method for emissions accounting based on energy certificates, and not only for renewables, said Todd Bianco, chief economic and policy analyst for the state's PUC.

"Coal has certificates too, and we follow those certificates to sort of understand what our emissions are," Bianco said in a Monday phone interview with *RTO Insider*. "And we use renewable ones to help us calculate how much we've reduced emissions from the baseline."

But, echoing Deora, Bianco said the clean energy and emissions certificates are not aligned.

"Folks have ... focused on … the renewable aspect, which is great, but when you try to do the actual carbon emissions, you also have to have the highest fidelity to be able to show, well, who does have those carbon emissions? You're in a power pool; there's gas and coal and oil, let's say, so if you didn't use them, who did?"

During the NARUC panel, Bianco ran through a few scenarios in which the allocation of certificates could get blurred or just confusing. For example, if two businesses are on the same power system, and one is procuring wind energy and one gets electricity from a fossil fuel plant, who gets the certificates for the clean energy?

If a state agency is just looking at compliance for a renewable portfolio standard, Bianco said, it might use the clean energy credits from the wind-powered business to zero out the greenhouse gas emissions from the firm getting its electricity from the fossil fuel plant.

The agency could make "a legally defensible claim that the state is not evading emissions consistent with our statutory mandate," he said. "But what would those two businesses tell their investors?

"And that's where the certificates could go to the next level. Everybody has to agree," Bianco said. "It's no longer that I can make my claim in a bubble. Everyone has to agree to how they're going to measure."

Common Tool Set Needed

The General Services Administration announced its first *24/7 CFE agreement* in November, working with Entergy to provide clean power to federal buildings in Arkansas. Moving ahead, Deora said, the federal government could be modeling its clean energy procurements on corporate practices.

"We're going to [be] technology neutral, so we're inclusive of all carbon-free electricity technologies beyond what is traditionally considered renewable," he said. Nuclear, hydropower and fossil generation with carbon capture will be included.

Federal guidelines released in August also stress "temporal matching" on an annual and hour-for-hour basis, and "locational matching," so that CFE is generated in the same region or service territory in which it is consumed, Deora said.

Like the federal government, Google is looking beyond wind and solar, Beck said, and the diversity of energy resources is going to make data accessibility and transparency critical for clean energy and emissions accounting.

"Whether your state has an RPS or not, you've probably got the federal government in your state; you probably have Google and other large energy customers," she said. "Sorting out these inconsistences [in emissions accounting] and having systems in place to enable this data and this transparency is going to be critically important.

"We cannot continue figuring out these systems in silos," Beck said. "Our sustainability goal is not going to be same as the government's; it's not going to be the same as the next company's. But if we have a common tool set, we can use that to achieve our goals, hopefully in a meaningful and transparent way." ■

FERC Orders New Reliability Standards in Response to Uri

By Michael Brooks

WASHINGTON — FERC on Thursday approved two new NERC reliability standards in response to the February 2021 winter storm that nearly led to the collapse of the Texas Interconnection (*RD23-1*).

According to FERC staff, EOP-012-1 (Extreme cold weather preparedness and operations) and EOP-011-3 (Emergency operations) implement about half of the standards-related recommendations from the commission's joint inquiry with NERC into the Texas grid operator's poor performance during Winter Storm Uri.

The standards require generator owners to implement several measures to prevent their units from freezing during extreme cold-weather events. These include constructing retrofits at existing units based on the "extreme cold weather temperature" where they are located, defined as the lowest 0.2 percentile of the hourly temperatures measured in December, January and February since Jan. 1, 2000.

Owners will be required to submit corrective action plans if the temperature is at or above the unit's designated extreme and one of the following occurs:

- a forced derate of more than 10% of the total capacity of the unit, and exceeding 20 MW, for longer than four hours in duration;
- a start-up failure where the unit fails to synchronize within a specified start-up time; or
- a forced outage.

Generator owners and operators will also need to conduct annual staff training on cold weather preparedness and develop procedures to improve the coordination of load-reduction measures during an emergency.

The new standards were approved by the NERC Board of Trustees in October as part of Project 2021-07. (See *NERC Board Approves New Cold Weather Standards*.)

"These new standards will help to prepare our nation's grid and our grid operators so they can provide power to consumers in the face of extreme weather," acting FERC Chairman Willie Phillips said in a statement. "I am pleased that NERC and its regional entities acted swiftly to propose these reliability standards so that my fellow commissioners and I could move decisively and vote today to ensure the reliability and resilience of the bulk power system."

Despite unanimous approval at FERC's open meeting Thursday, the commission acknowledged that more work needs to be done. Project 2021-07 is only Phase 1 of a three-phase process at NERC in response to the storm, and staff noted that more proposed standards will be brought before the commission by the end of the year to address the second half of the relevant recommendations.

Standard's Shortcomings

FERC also found EOP-12-1 to be lacking, and it directed NERC to revise it to "to clarify certain language, enhance certain standard requirements, include criteria on permissible constraints and identify the appropriate entity that would receive the generator owners' constraint declarations under the standard," staff said in presenting the order.

"EOP-012-1, in its current form, includes undefined terms, broad limitations, exceptions and exemptions, and prolonged compliance periods," FERC said in its order.

Among the elements FERC required be included in the next version of the standard are a deadline for the completion of corrective action plans and a shorter grace period for generators to implement those plans and freeze-protection measures. The approved standard gives generators five years to upgrade their facilities, for example.

"Although we are giving NERC the discretion to determine what the effective date should be shortened to, we also emphasize that industry has been aware of and alerted to the need to prepare their generating units for cold weather since at least 2011," FERC said. After the January 2018 South Central cold snap, a joint FERC-NERC *report* found "that one-third of the generator owners and operators surveyed 'still had no winterization provisions after multiple recommendations on winter preparedness for generating units.'"

"NERC should consider the amount of time that industry has already had to implement freeze-protection measures when determining the appropriate implementation period," the commission ordered.

Commissioner Allison Clements criticized EOP-012-1's deficiencies at length during the meeting. "This is one of the more important votes we are taking during my time at the commission," she said before recalling the deaths

FERC staff present the commission's order approving two new NERC reliability standards to commissioners at their open meeting Feb. 16 in D.C. | *FERC*

and economic damage Texans experienced during the 2021 storm as a result of prolonged power outages.

"There are a number of good measures in what we accept today, to be sure," Clements said. "But the critical generator weatherization requirements as they were proposed, to be frank, are not up to the task."

EOP-012-01 requires that existing generators be able to operate for at least one hour continuously at their designated extreme low temperature. "Yeah, one hour," Clements said sardonically. "Needless to say that doesn't bring total comfort that we will ensure we get through the next multiday event like Winter Storm Uri."

She also said the amount of time allowed for implementation "does not reflect the urgency we feel."

The commission gave NERC a year to submit the revised standard.

Although ERCOT's markets are not subject to FERC regulations, generators in the Texas Interconnection are subject to NERC's reliability standards. But Commissioner Mark Christie said market design was the bigger issue.

"These [standards] may have a positive impact ... for generators, but ... one of the problems that prompted [what happened during] Uri was the market design" in ERCOT, he said. "And I think the same issue applies in many other RTOs. It's a much bigger issue about how these markets are structured and how they deliver the reliability that we need." ■

Federal and State Regulators Look into How to Improve Grid Security

Joint Transmission Task Force Focuses on Planning Fixes and CIP-014 Improvements

By James Downing

WASHINGTON — The sixth meeting of FERC's Joint Federal-State Task Force on Transmission, held Wednesday, looked into how the grid can be better protected against physical attacks, which have been on the rise recently.

"There are well over 50,000 high-voltage substations across North America, and more than that if you include those that only support the distribution system," NERC CEO Jim Robb said at the meeting, held concurrently with the National Association of Regulatory Utility Commissioners' Winter Policy Forum. "That's a tremendous amount of infrastructure to think through how to protect responsibly, and to really think through the tradeoffs that need to be made between risk and consequence and the investments that you make between protection and prevention, versus response and recovery."

Protecting all of those assets is not feasible, as it would cost far too much, but not every substation is a critical asset that needs high levels of security, Robb said.

Even most incidents at substations would not qualify as attacks, with "criminal mischief" — in which people steal copper or vandalize substations — being much more common than occurrences like the attacks in North Carolina and Washington state and the foiled plot in Baltimore.

"But over the last six to nine months, we've seen more and more attacks, which would exceed the threshold of criminal mischief and really rise to the level of sabotage," said Robb.

The increased concern over the rise in attacks is appropriate, but Robb said that only 5% of incidents at substations actually impact the grid, either by causing some customers to lose power, or by putting the system into a contingency operation mode.

CIP-014 (Physical security) was issued after the Metcalf Substation attack in Silicon Valley a decade ago. Its purpose is to ensure that physical attacks on substations did not lead to major, cascading outages on the grid, and so it focuses on substations with more power flows, at 345 kV and above, said Robb.

"While many substations may not need to be technically CIP-014-compliant, their owners may very well build in protections because it's

Joint Federal-State Task Force on Transmission holds its sixth meeting Feb. 15. | *FERC*

the right thing to do," he added. "The utility sector generally leans in very, very hard on security matters, whether physical or cyber, to protect their assets and their ability to serve their customers."

One idea for updating CIP-014 might be to focus on the possibility of coordinated attacks on multiple substations, said Robb. It could also shift from focusing on preventing cascading outages to preventing any outages at all, he added.

Puesh Kumar, director of the U.S. Department of Energy's Office of Cybersecurity, Energy Security and Emergency Response, told the task force that the law enforcement community is very focused on the issue, as he is regularly meeting with the FBI and the Department of Justice.

"When we think of the law enforcement angle, that again doesn't need to just be at the FBI level," Kumar said. "We need to make sure that we have local law enforcement; we have state law enforcement also engaged in this conversation and really recognizing and appreciating the criticality of the electricity infrastructure across the country."

Broad Solutions Save Money

With tens of thousands of physical sites requiring protection around the country, along with the need to protect the grid against cyberattacks and extreme weather, it is important to focus on solutions that cut the risk across the board, Kumar said.

"How are we investing in tools and technologies that can also help us buy down the risk?" Kumar said. "It's not just the standard that buys down risk; there's a lot of other ways and tools and technology as part of the puzzle that we have to be thinking about."

The biggest threat from a single-asset perspective is electric power transformers, which are just part of a substation's equipment and thus could benefit from increased protections compared to other assets, PPL Electric Utilities Chief Information and Digital Officer Matthew Green told a panel at the NARUC summit earlier in the day. The risk around transformers can also be mitigated by ensuring the industry has enough backup equipment to replace anything that is damaged.

While physical attacks are a concern and a priority for PPL that is being addressed by prudently investing to protect the riskiest assets, it is not Green's main worry.

"I'm actually more concerned around cybersecurity attacks," Green said. "And, actually, in 2022 the single biggest contributor to outages for customers in United States continues to be weather-related outages. So that is also still a top concern."

Investments to prevent outages from those causes need to be made prudently, after an

FERC/Federal News

accurate assessment of the relevant risks, he added.

The U.S. grid is decentralized, which means attacks on individual assets are unlikely to really have a major impact reliability across the board, said Kansas Corporation Commissioner Andrew French. But coordinated attacks are an increasing concern, so French asked Robb what the best strategy to address those would be.

One way of complying with CIP-014 is to remove any kind of critical substations from a utility's network, which can happen in the process of normal grid planning or in coming back after a storm.

"I would love to see that number continue to decline, as we can build more and more redundancy into the system and less dependence on a subset of the assets around the grid," Robb said.

Beyond that, coming up with a strategy to deal with the risk of coordinated attacks is tricky because it is not financially feasible to harden every grid asset out there. Having backup equipment available to minimize any downtime would help.

"One of the issues that's vexing the industry right now, with all the supply chain challenges that we have, is that a lot of this equipment isn't standardized," Robb said. "So, I think that's an opportunity as we as we move forward."

Changes Needed for CIP-014?

Michigan Public Service Commission Chair Dan Scripps said it makes sense that CIP-014 is site-specific, but he asked whether it would also be prudent to have some kind of minimum level of protection spelled out in the standard.

The standard is fairly new, Robb said, so the industry has less experience from which it can draw best practices, but minimum standards are one of the updates that should be considered.

"There's nothing that would prevent a state from imposing its own security requirements on any of these assets," Robb said. "So, if to the extent that any of you feel that the NERC standards don't go far enough to protect the systems under your jurisdiction from issues that you're concerned about, you can always go further."

Physical is usually an afterthought when it comes to planning the grid, but acting FERC Chairman Willie Phillips argued it would make sense to change that.

"If we consider it on the front end, I think we do have an opportunity to do something about what can be a very costly process," Phillips said.

PJM has a process in which it works to minimize the number of critical infrastructure sites on its grid through planning, Phillips said, and that could work well elsewhere, as long as information on sensitive sites is handled correctly.

Connecticut Public Utilities Regulatory Authority Chair Marissa Gillett said that it might make sense to deal with physical security issues in the transmission planning process,

DOE Office of Cybersecurity Energy Security and Emergency Response Director Puesh Kumar and NERC CEO Jim Robb address the joint task force on Feb 15. | *FERC*

but she worried that it would give the industry another excuse to shut out the states from the process in ISO-NE.

"I just think we need to be cognizant of some of the challenges around them," Gillett said. "Especially because of that tension ... between wanting to have openness while needing to respect the concerns about disclosing too much about physical security threats." ■

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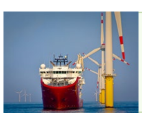

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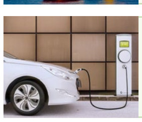

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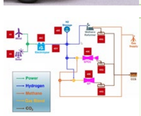

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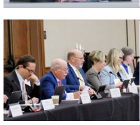

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FERC/Federal News

Heinrich: Pipeline Permitting 'Reform' Will also Benefit Clean Energy

ACP Energy Storage Forum Focuses on Need for Bipartisan Policy in Divided Congress

By K Kaufmann

Sen. Martin Heinrich (left) talks with Jason Grumet, ACP's new CEO, at Wednesday's Energy Storage Policy Forum on Feb. 15. | *© RTO Insider LLC*

WASHINGTON — Legislation to streamline the permitting of clean energy projects, including new transmission lines, may require bipartisan collaboration and tradeoffs, according to Sen. Martin Heinrich (D-N.M.).

While Republicans and some Democrats, such as Sen. Joe Manchin (D-W.Va.), are focused on permitting new natural gas pipelines, there is an "upside" to the situation, Heinrich said in a brief interview Wednesday at the American Clean Power Association's Energy Storage Policy Forum.

"If we can do permitting reform and do it well, so much of the capital is actually going to flow to clean electrons. So that sets us up for the potential for a bipartisan solution to all this," he told *RTO Insider*.

The senator pointed to cost allocation as one of the "tough issues" to be worked through to prevent states and their residents from "paying for something they're not benefiting from. But you have to have ways of sharing costs across multiple jurisdictions, multiple businesses and making sure that costs and benefits get shared proportionately."

Conversations about the issue among Democrats and Republicans in the House and Senate are "more sophisticated than they have been in the past," he said.

A compromise on pipelines could have "the potential to make this a bipartisan solution," said Heinrich, who sits on the Senate Energy and Natural Resources Committee, which Manchin chairs. "People have to realize that because of where the markets are heading, anything we do in this space is naturally going to benefit the clean energy transition."

The need for the storage industry to move ahead with a strong bipartisan strategy was a key theme at the one-day event, with Jason Grumet, ACP's new CEO, setting the tone in opening remarks that called on attendees to "find a way to balance the audacity of this transition with the humility of the limitations that all technologies have."

Coming to ACP after 15 years as president of the Bipartisan Policy Center, Grumet said, "The challenge is that … we have to make a century-scale transition in 25 or 30 years. … There's been a lot of advocacy, which is intended to be supportive, which has not been honest, which essentially said, 'We can have 100% clean power by 2035 and leave oil and gas in the ground.'

"That's not true. It undermines our credibility, makes us seem like hypocrites," he said. "We just have to be really honest and pragmatic about the challenge. We're going to have a multi-technology solution," including natural gas.

"We have to recognize that storage, solar, wind, nuclear, clean gas are all going to be critical to actually decarbonizing the economy, and that's also helpful because we need a lot of friends," Grumet said. "We have a divided country, a divided Congress. You can't get anything done unless you have broad-based appeal."

Security, Affordability, Climate

ACP's choice of Grumet to lead the organization, with his strong roots in bipartisan work, comes at a pivotal moment for the industry.

The U.S. energy storage market is "past the inflection point," said Jason Burwen, ACP vice president for energy storage. The industry put about 9 GW of new storage online in 2022, and according to the U.S. Energy Information Administration, another 21 GW of new storage could be deployed on the grid by 2025.

Further, the Inflation Reduction Act provides a new tax credit for standalone storage, which opens the way for storage to be used as a grid resource. California has more than 4 GW of storage online, not all of it paired with solar, and could need up to 48 GW by 2045, according to the *California Energy Commission*.

"The remarkable growth in U.S. battery storage capacity is outpacing even the early growth of the country's utility-scale solar capacity," the EIA said in a *December update*. "U.S. solar capacity began expanding in 2010 and grew from less than 1.0 GW in 2010 to 13.7 GW in 2015. In comparison, we expect battery storage to increase from 1.5 GW in 2020 to 30.0 GW in 2025."

Grumet sees energy storage as a central answer to the economic and political challenges of the moment. "Security, affordability and climate all have to be engaged at once," he said. "The effort to focus on one of those three elements turns out to be pretty crappy energy policy that tends to lead you towards one side or the other of the political spectrum."

While different mixes of generation can move the economy toward net-zero, energy storage is a hinge for all the of them, he said.

But bipartisanship can be a double-edged sword. "There's a ton of bipartisan support for 'don't do anything near me' … which is absolutely at odds with what we need to do," Grumet said. "We have a society based on this premise of local control and community rights, and we have to honor that premise, [but] you cannot transition that economy with community-based decisions.

"So we've got to figure out, again, as an industry, how do we make it clear that we have a shared national interest?" he said.

Starting from Nowhere

In an on-stage conversation with Grumet, Heinrich agreed that energy storage must be "socialized" as a "bread-and-butter" solution to a range of energy challenges.

"When I came to the Senate, and that was after four years in the House, there were a very small number of senators [who] were really focused on what are the nuts and bolts to really make the energy transition work," he said. But as climate change has become an increasingly important issue, "the entire [Democratic] caucus is focused on solutions and looking for solutions.

"So if you come with credibility and say, 'This policy or this technology is going to be absolutely critical,' people start with an open mind," he said.

Bipartisan solutions will also be needed to address clean energy supply chain issues and dependence on China for the processing of critical minerals, such as lithium, and manufacturing of key storage components.

"What we have to recognize is that industry doesn't exist in a meaningful way in the continental U.S. today, and we need to change that," Heinrich said. Tax credits for clean energy manufacturing in the Inflation Reduction Act have catalyzed new interest and activity in developing an industrial policy, he said, "but we're really starting from practically nowhere."

At the same time, "we don't want to shut down for seven years," while domestic supply chains are built out, he said. "You can't wait until we make everything here to start creating solutions that we know we need today. … Why this is so complicated a problem is because we are really reorganizing the way we power our entire society."

Grumet raised ongoing concerns on both sides of the aisle in Congress about China's acquisition of U.S. technologies and intellectual property, which have resulted in "a reluctance to have any connection at all" with the country.

Both he and Heinrich see new opportunities for U.S.-Chinese joint ventures growing out of the snowballing investments in clean tech manufacturing in the U.S., triggered by the IRA.

While some European countries have labeled the law as "protectionist" and say it will draw investment away from the EU, Heinrich said, it shows that "we're serious about taking a new direction." ■

DC Circuit Upholds FERC on Montana PURPA Project

By Hudson Sangree

The D.C. Circuit Court of Appeals on Feb. 14 upheld a FERC decision that allowed a solar-and-storage project in Montana to be certified as a qualifying facility under the Public Utility Regulatory Policies Act even though its total power production capacity exceeded the law's 80-MW limit (*21-1126*).

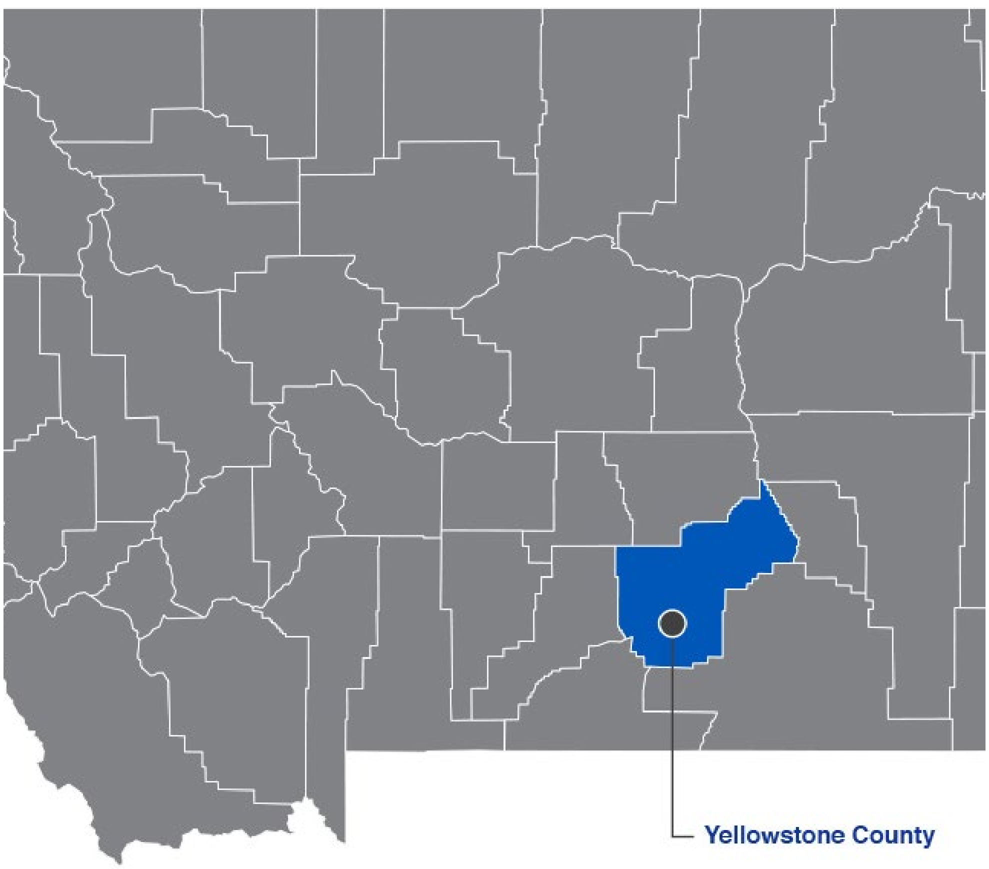
FERC had justified its March 2021 decision under its longstanding "send-out" analysis, which determines a facility's capacity based on the electricity it can actually deliver to an interconnecting electric utility.

Broad Reach Power's Broadview Solar project included solar panels with a gross capacity of 160 MW DC and a 50-MW battery, but the project's inverters allowed it to produce and deliver only 80 MW to its interconnection with NorthWestern Energy's transmission system.

"The commission's determination that Broadview is a qualifying facility with a 'power production capacity … not greater than 80 MW' because its component parts, working together, produce no more than 80 MW of grid-usable AC power was reasonable and well supported by the statute's text, structure, purpose and legislative history," the D.C. Circuit said in its decision.

In upholding FERC's order, the court rejected challenges by NorthWestern and the Edison Electric Institute, which argued that FERC exceeded its authority because the "power production capacity" of Broadview's facility should be the total amount of DC power generated by the solar array and not the grid-usable AC power produced by the inverters working in conjunction with the solar array and battery.

PURPA was enacted in 1978 to encourage alternative energy generation by "qualifying small power production facilities" (QFs). It requires utilities such as NorthWestern to purchase a QF's generation output, "providing those facilities with a guaranteed market," the court noted.



The Broadview solar-and-storage project at the center of the case is in Yellowstone County, Mont. | *Broad Reach Power*

Montana has been an especially contentious front for PURPA disputes in the West, where utilities contend the law requires them to integrate large volumes of QF renewable resources at contracted rates far above market rates.

Circuit Judge Justin Walker dissented in part from his colleagues on the three-judge panel, Circuit Judge Cornelia Pillard and Senior Circuit Judge David Sentelle, who drafted the majority opinion.

PURPA "gives lucrative benefits to small facilities that produce solar power," Walker wrote. "It defines them as facilities with a 'power production capacity' of no more than 80 MW. … Because Broadview can produce 80 MW for its inverters while it simultaneously produces 50 MW for its battery, Broadview's facility is capable of producing more than 80 MW of power. So it is too large to be a 'small facility.' For that reason, I would grant the petitions, vacate the rehearing orders and remand to FERC for reconsideration."

The case took an unusual twist at FERC before reaching the appeals court.

In September 2020, FERC broke with its own precedent by deciding the Broadview project could not be certified as a QF because it exceeded the 80-MW cap despite its limited interconnection. Its decision aligned with the arguments of NorthWestern and EEI.

The commission's lone Democrat at the time, Richard Glick, dissented. The commission's decision, Glick wrote, "will make QF status turn on the capacity of any one component of the facility, rather than the actual power production capacity of the facility itself. That conclusion finds no support in the statute, our precedent or common sense." (See *Montana Hybrid Ruling Departs from PURPA Precedent*.)

In March 2021, with Glick now chairman, FERC set aside its prior ruling, reinstated its send-out analysis, and determined Broadview could be a QF. (See *FERC Reverses Ruling on Montana QF*.)

"It is not fathomable to conclude that Congress would be more concerned about the electricity a project could theoretically generate on its own but not deliver to any customer," Glick said at the time. "Instead, since the statute is all about the sale of a project's output, the appropriate way to look at a facility is to assess how much can actually be sold to the purchasing utility." ■

CAISO/West News

PG&E Pleads Not Guilty to Manslaughter Charges

By Hudson Sangree


The Zogg fire raged in rural Northern California in late Sept. 2021. | *Jeff Head via Flickr*

Pacific Gas and Electric pleaded not guilty Wednesday to 11 charges stemming from the September 2020 Zogg Fire, including four counts of involuntary manslaughter and three felony charges of recklessly starting the wildfire.

The California Department of Forestry and Fire Protection (Cal Fire) determined that a pine tree falling onto a PG&E power line ignited the 56,000-acre blaze in forested areas of Shasta and Tehama counties. It killed four people who could not escape the flames, including a mother and her 8-year-old daughter, and destroyed more than 200 structures.

PG&E said in a statement Thursday that it intends to fight the charges filed by the Shasta County District Attorney's Office. The judge set a tentative trial date of June 6, but PG&E could settle the case rather than go before a jury.

"As we have stated previously, we accept Cal Fire's determination that a tree falling into our powerline caused the 2020 Zogg Fire," the utility said. "However, we believe PG&E did not commit any crimes, and that the conduct of our coworkers and contractors reflects good-faith judgment by qualified individuals. We have informed the court that we intend to defend ourselves against the remaining charges."

On Feb. 1, a judge dismissed 20 of the 31 charges filed by the prosecutor's office but said there was sufficient evidence to try PG&E for seven felonies and four misdemeanors. (See *PG&E Can be Tried Again for Manslaughter*.)

Under California law, involuntary manslaughter, a felony, is a category of homicide in which the defendant is alleged to have committed a lawful act "which might produce death, in an unlawful manner, or without due caution and circumspection."

The district attorney's office said in its September 2021 criminal complaint that PG&E had failed in its "legal duty to safely operate electrical transmission and distribution lines in a manner that minimizes the risk of catastrophic wildfires" by failing to clear the damaged and dangerously leaning pine tree.

When the charges were filed, PG&E CEO Patti Poppe said "two trained arborists walked this line and, independent of one another, determined the tree in question could stay."

"We trimmed or removed over 5,000 trees on this very circuit alone," Poppe said.

The Zogg Fire was the second time that the state's largest utility has been charged with manslaughter.

PG&E pleaded guilty in June 2020 to 84 counts of involuntary manslaughter and one count of arson in the Camp Fire, which destroyed much of the town of Paradise on the morning of Nov. 8, 2018. A 100-year-old C hook on a PG&E transmission tower broke, allowing a line to drop and spark dry vegetation below.

The Camp Fire and a spate of Northern California wine country fires in October 2017 forced the utility into bankruptcy and led to a multibillion-dollar settlement with fire victims. ■

CAISO/West News

Nuclear Bill Advances in Wash. House

By John Stang

Conceptual drawing of a NuScale Power advanced modular reactor complex. | *NuScale Power*

OLYMPIA, Wash. — The House Environment & Energy Committee unanimously recommended Thursday that the full House of Representatives pass a bill to add advanced nuclear reactor technology to the alternative power sources that the state uses to replace fossil fuels.

House Bill 1584, sponsored by Rep. Stephanie Barnard (R), would add advanced nuclear to solar, wind, hydroelectric dams, landfill methane and other sources of non-fossil fuel power sources. Washington is legally required to eliminate 95% of its greenhouse gas emissions by 2050. Barnard represents the Tri-Cities, home of the 1,200-MW Columbia Generating Station nuclear plant, which produces roughly 12% of the state's electricity.

The owner of the plant, Energy Northwest, supports the bill, as does the Grant County Public Utility District, which is considering building a small modular reactor (SMR) complex within its territory.

Each modular unit would be a mini-reactor capable of generating 50 to 300 MW. SMRs are designed to allow additional modules as needed, with 12 modules being the theoretical maximum. Compared with conventional nuclear, the concept is supposed to result in lower costs, faster construction times and more flexibility in tailoring a reactor complex to its customers' needs.

Grant County PUD is looking at a design by Maryland-based X-energy but has not decided whether to pursue an SMR.

"We're looking at advanced nuclear technology because of growth in our county," Bill Clarke, a lobbyist representing the PUD, told the committee.

NuScale Power of Portland, Ore., became the first SMR developer to receive approval for its 60-MW design by the Nuclear Regulatory Commission. The company plans to submit an improved follow-up version of that design to the commission that includes increasing output to 77 MW each. The company is pursuing building its first complexes in Idaho Falls, Idaho, and Romania by the end of this decade.

Leaders from both Energy Northwest and the Tri-Cities want to attract NuScale to build at the site of two never-completed reactors next to the Columbia plant. That site has infrastructure in place to build either reactors or reactor components.

At Thursday's committee hearing, Roger Lippman of Nuclear Free Northwest opposed the bill, saying the term "advanced nuclear technology" is not defined in the bill. He added that no advanced nuclear technology plants have begun operating in the U.S., meaning the technology does not have a proven track record. ■

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ERCOT News

Skelly's Grid United Quickly Making Waves

North Plains Connector Just 1 of 3 Projects on Drawing Board

By Tom Kleckner

Four years ago, transmission developer Michael Skelly was on the outside of the electric industry looking in.

Clean Line Energy Partners, the company he had founded to deliver renewable energy over HVDC transmission lines, had sold off its portfolio of projects and closed its doors. Having taken a senior adviser's role at Lazard Asset Management, Skelly was invited to speak at the American Wind Energy Association's WINDPOWER 2019 conference. He said that while Clean Line hadn't been able to "win the World Cup of transmission," he was hopeful that "the second mouse gets the cheese in the transmission world." (See *Out of the Game, Skelly Still High on Wind Energy*.)

It appears Skelly could be one of those mice.

As CEO of Houston-based Grid United, Skelly now leads a company intent on uniting the nation's grid by building long-distance, interregional transmission to ensure access to low-cost power "when and where it is needed" — in other words, pretty much what Clean Line was trying to do.

Skelly's company made a big splash recently by announcing a collaboration with ALLETE to build the North Plains Connector, a $2.5 billion, "first-of-its-kind" project that would span across the Western and Eastern interconnections. The 385-mile HVDC line will run from SPP's wind-rich North Dakota footprint to the Colstrip power plant in Montana, where two 500-kV lines run into the Pacific Northwest. (See *Transmission Project Would Span Across Interconnection Divide*.)

Skelly said a number of wind projects are being built around Colstrip. Along with the region's hydropower assets, it will give North Plains a chance to move power in either direction.

"During times when there's excess generation in Montana, either from wind or solar or the spring hydro runoff, it will move power to the east into the Midwest," Skelly told *RTO Insider*. "At times when there's high load and low wind during the night and there's no storage, it will power the West."

The project, he said, will effectively improve renewable resources' effective load-carrying capability, a measure of their ability to produce energy when the grid is most likely to experience shortfalls. Skelly said his staff did a backcast on the project to see how it would have performed under extreme weather conditions.

Mike Skelly | *© RTO Insider LLC*

The North Plains Connector project will span North Dakota and Montana, connecting the Western and Eastern interconnections. | *Grid United*

"As it turns out [during the February 2021 winter storm], they were short power in the Upper Midwest, and the Pacific Northwest had a lot of power. And similarly, when there was a heat over Seattle and Portland [last summer], there was plenty of power available in the Midwest," Skelly said. "Our transmission is a very good way to deal with those extreme events, particularly transmission that can connect things that are a thousand-plus miles apart, because you've got very different weather phenomena."

Grid United is also involved with the Southline Transmission Project, a 280-mile, high-voltage circuit between Tucson, Ariz., and the El Paso Electric system. The project also includes a 120-mile upgrade of existing Western Area Power Administration transmission lines.

"The focus of these grid projects is the things that we all know need to happen to improve resiliency and adapt to the change of generation, but that sort of fall between the cracks of the planning processes," Skelly said, explaining how Grid United's strategy is different from Clean Line's.

"So, the model may be a hybrid model where we own interests and projects, and utilities own interests, or maybe the utilities own the whole thing. It will depend a lot on the specific project," he said. "From a development perspective, our approach to development is to start to do a lot of the groundwork and a lot of the right-of-way work before we get down to the regulatory processes."

ERCOT News

And then there's Pecos West, a 280-mile, 525-kV DC line from a substation in the middle of West Texas to El Paso. The project, still on the drawing board, would link ERCOT with the Western Interconnection. The Texas Public Utility Commission on Thursday rejected Grid United's application for a "partial" certificate of convenience and necessity (*53758*). (See related story, *Texas PUC Rejects CCN for Grid United's Pecos West*.)

In a *filing* with the PUC on Feb. 13, Grid United said a preliminary order is not necessary, pointing to its pending motion to abate. It said the abatement will give it time to work with ERCOT in obtaining any required studies or evaluations and that it will likely amend the CCN application with additional data that commission staff have requested. Grid United also wants a ruling from FERC that the project won't affect ERCOT's non-jurisdictional status; former FERC Chairs Richard Glick and Pat Wood have both said recently that such links can be made between the Texas grid and the other two interconnections without changing that status.

PUC staff, for their part, filed a *motion* in December to dismiss, saying it needed more information from Grid United.

"The PUC wants you to file a bunch of alternatives before you do any right-of-way work. We were trying to do the right-of-way work upfront, and then the filings," Skelly said. "We apply; they asked for more info; we go back. We're in that process right now. So far, it feels like it's going fine."

The North Plains Connector project is further advanced. Grid United has been working with SPP staff since last year; a feasibility study's scope was approved in September by the Transmission Working Group. Former SPP COO Carl Monroe sits on Grid United's four-person advisory board.

Skelly said that FERC's efforts to improve the generator-interconnection process and focus on making transmission easier to site, build and fund, has raised public recognition of the grid's importance.

"There's a heightened awareness of the need for transmission," Skelly said. "Even when you talk to a landowner and you tell them what you're doing, they go, 'Yeah, the grid; we got to fix that grid. We've got to make that grid better.' You go to a cocktail party and you talk about the grid, people are like, 'I heard there's some issue with the grid. What's going on with that?'"

Another sign of transmission's importance is what has happened to the projects Clean Line left behind.

The Western Spirit project, a 155-mile 345-kV line in New Mexico, was *energized* in 2021. Invenergy is still working on the Grain Belt Express, an 800-mile HVDC line capable of carrying 5 GW of energy that starts in Kansas, runs through Missouri and ends at the Illinois-Indiana border.

"It's still alive," Skelly said. "Well, more than alive. They've ordered equipment. … That's huge. Ordering equipment is a big step. You don't do that unless you're going to build it.

"Those are our old projects, so we're excited about that," he added. "You go through all that and, 'Wow! Yeah, things have changed since 2019.'" ■

ERCOT News

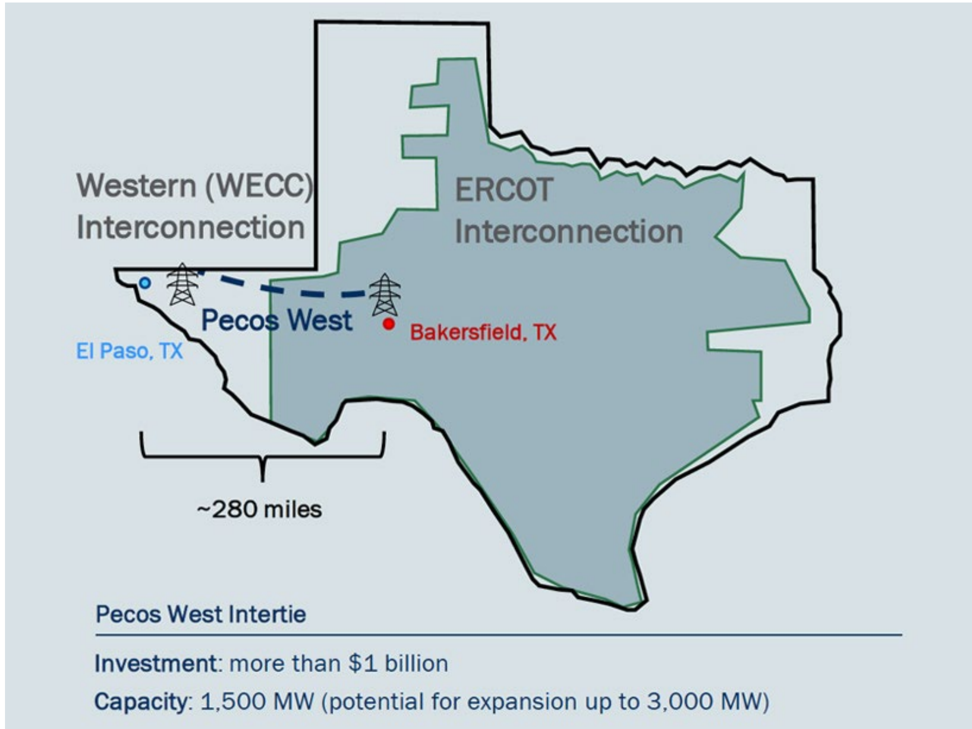
Texas PUC Rejects CCN for Grid United's Pecos West

PUC Joins Lawsuit vs. EPA; Commissioners Leading RTO Groups

By Tom Kleckner

Texas regulators last week denied Grid United's request to build an intertie between ERCOT and the Western Interconnection, saying they did not have the authority to approve the application.

The Public Utility Commission cited state law Thursday in rejecting a partial certificate of convenience and necessity for Pecos West, a proposed 280-mile, 525-kV HVDC intertie connecting the Lower Colorado River Authority's (LCRA) system with El Paso Electric (EPE), which sits in the Western Interconnection (53758).



Grid United's proposed Pecos West intertie | *ERCOT*

PUC staff argued in a preliminary order that state law prohibits the commission from granting Grid United's request. They said only LCRA and EPE, as owners of the facilities that would be interconnected, can be granted the CCN.

"Grid United Texas does not qualify under [Texas' Public Utility Regulatory Act] as an entity that could be designated by El Paso Electric or LCRA to exercise the CCN rights reserved to them," staff said. "Thus, under no circumstance can the commission legally grant Grid United Texas a CCN or any rights emanating from a CCN for the proposed interconnection."

Houston-based Grid United had sought "partial authorization" from the commission. It said its application was limited to the intertie and not the right to construct or operate the line. Intervening parties supporting the application said state law should not apply because the proposed line is not a transmission facility, but staff rejected that argument.

"Only the owners of the existing facilities to which the proposed interconnection will directly interconnect can be certificated for the proposed interconnection," they said. Staff pointed out that, as Grid United is not a utility under Texas law, it can't be designated by either LCRA or EPE to exercise their respective rights to "build, own or operate a new transmission facility."

Initial ERCOT studies last year determined Pecos West would offer "significant" reliability benefits to the Texas grid, providing new markets for producers and reduced curtailment of renewable resources with "negligible" impact on prices.

At issue, however, is Texas' right-of-first-refusal law, which was passed in 2019 and is now before the U.S. Supreme Court. Texas last year asked the high court to review an appeals court's remand back to a district court over the latter's claim that the ROFR law violates the U.S. Constitution's dormant Commerce Clause. (See *Texas Petitions SCOTUS to Review ROFR Ruling*.)

Commissioner Jimmy Glotfelty said he would have preferred to set the docket aside and wait for the Supreme Court's ruling or further ERCOT studies, but he indicated his hands were tied.

"I think the law, unfortunately, tells me that a right of first refusal is a right of first refusal. And according to this docket at this time, I would have to support the staff's position," he said.

Glotfelty, who has worked with Grid United founder Michael Skelly in the past, said he struggled with the decision. (See related story, *Skelly's Grid United Quickly Making Waves*.) He noted the HVDC tie would provide the state with resilience, reliability and low prices, "three things that our citizens need and that our [legislative] leadership has directed us to improve."

"There are numerous points in the filings that in my opinion are right on target, and we should be able to permit these types of lines," he said. "The biggest barrier to HVDC in this case is the [ROFR] law that the legislature has passed. … I want to push this line and other lines, but this law was passed and it's our job to implement the statute."

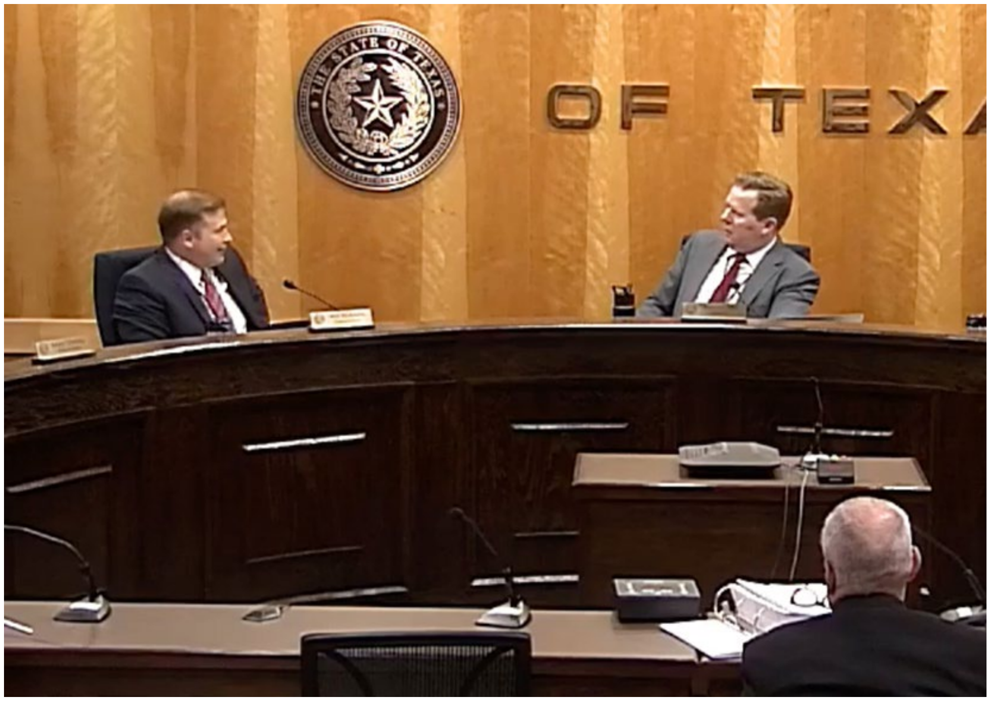
"We're always looking for ways to increase competition in the market. Competition delivers great results, and we've seen that historically," Commissioner Lori Cobos said. "At this time, the law is just not written to allow this type of construct."

Grid United withdrew the application on Friday, asking that it be dismissed without prejudice. Spokesperson Ally Copple said the company remains committed to developing Pecos West. It has identified preliminary corridors and hoped for regulatory approvals in 2024. Under that scenario, Pecos West could be operational as early as 2029, Copple said.

"We have reviewed the preliminary order and the relevant statute, and we are confident there are other paths to move the project forward," she said.

ERCOT News

Jimmy Glotfelty reads his statement on Grid United's CCN application. | *Admin Monitor*



Commissioner Will McAdams (left) and Chair Peter Lake during PUC's open meeting. | *Admin Monitor*

PUC Joins Lawsuit vs. EPA

The PUC agreed to join Texas' *lawsuit* before the 5th U.S. Circuit Court of Appeals over the EPA's rejection of the state's proposed plan to control emissions that drift into neighboring states. Texas Attorney General Ken Paxton says the agency had "no good reason" to reject the plan (23-60069).

The state is one of more than 20 that, under EPA's Cross-State Air Pollution Rule (CSAPR) plan, must establish NO_x emissions budgets beginning with the 2023 ozone season (May 1-Sept. 30). The agency says the reductions are necessary to address upwind states' interstate transport obligations. (See "Staff Defer Comment on CSAPR," *ERCOT Technical Advisory Committee Briefs: July 27, 2022*.)

The PUC also agreed to join with the Texas Commission on Environmental Quality in its comments to EPA over its process for developing state plans to reduce greenhouse gas emissions.

Cobos, McAdams Step up at RTOs

Cobos, the PUC's liaison with MISO, will serve as president of the Entergy Regional State Committee. Comprising state regulatory commissioners from Arkansas, Louisiana, Mississippi and Texas, and members of the New Orleans City Council, the committee provides input on Entergy's transmission system operations and upgrades in MISO South.

Cobos is also the secretary for the Organization of MISO States, the RTO's state regulatory body, and sits on the grid operator's Advisory Committee.

"I can't say 'no' to really big challenges," she said.

PUC Chair Peter Lake complimented Cobos and Commissioner Will McAdams, the commission's representative on SPP's Regional State Committee. McAdams was recently selected to lead the grid operator's newly created Resource and Energy Adequacy Leadership team and appointed as the RSC's treasurer.

"You're both clearly gluttons for punishment," Lake said. ■

ERCOT News

CenterPoint to Invest $43B, Addressing Customer Growth

CenterPoint Energy said Friday it plans to increase its 10-year capital plan to $43 billion through 2030, with a focus on additional investments in grid reliability and modernization.

CEO David Lesar told analysts on an earnings call that the company has added $2.3 billion to the capex plan and identified an additional $3 billion of potential opportunities that will be folded in "when we believe we can operationally execute it, efficiently fund it, and minimize the regulatory lag associated in recovering it."

The Houston-based utility *reported* fourth-quarter earnings of $122 million ($0.19/share) and year-end earnings of $1.01 billion ($1.59/share), compared to $641 million ($1.01/share) and $1.39 billion ($2.28/share) for the same periods in the previous year.

"We continue to execute well; 2022 was truly an exciting and productive year," Lesar said during the call. "We are confident that this strong momentum will continue into the new year."

He noted it was the 11th straight quarter CenterPoint has exceeded or met its own expectations for earnings guidance. Lesar has been CEO for the last 10 of those quarters.

The infrastructure investment will be needed. Texas has added nearly 1.1 million jobs since the COVID-19 recession, Lesar said. Houston, CenterPoint's primary electric service region, has added 179,000 jobs and increased its population by almost 300,000 to nearly 7 million, he said.

"This is now like adding a city the size of Irvine, Calif., to our footprint in just one year," Lesar said. "We see this trend continuing as the Texas miracle keeps humming along.

"This growth is just one of the reasons we believe we are uniquely positioned as a company."

The company's share price closed at $29.22 Friday, a gain of 16 cents on the day.

Entergy Takes Hit from Grand Gulf

Entergy on Thursday *reported* earnings of $106 million ($0.51/share) for the quarter and $1.1 billion ($5.37/share) for the year. That compared to $259 million ($1.28/share) for 2021's fourth quarter and $1.12 billion ($5.54/share) for the year.

The results included a $551 million charge, $413 million after tax, for System Energy Resources Inc. (SERI), the Entergy subsidiary that owns the Grand Gulf Nuclear Station in Mississippi. FERC in December issued two orders involving the plant's customer rate impacts. The orders addressed a series of uncertain tax positions that SERI took.

The New Orleans-based company has begun *issuing refunds* to ratepayers. It *reached a $300 million settlement* with the Mississippi Public Service Commission last June.

"We still believe that a global settlement with the remaining retail regulators on terms similar to the agreement with the MPSC would be in the best interest of all parties," Entergy CEO Drew Marsh told financial analysts during the quarterly conference call. "It would resolve disruptive litigation uncertainty for SERI and our stakeholders, including our regulators, accelerate meaningful value to customers, avoid costly and unnecessary third-party litigation fees and allow all parties to move forward with fewer distractions."

Entergy's earnings exceeded Zacks Investment Research projections of 45 cents/share. Entergy's share price ended the week at $109.42, up $1.87 from Wednesday's close. ■

— Tom Kleckner

CenterPoint Energy has increased its capex plan to $43 billion through 2030. | *CenterPoint Energy*

ISO-NE News

FERC Denies RENEW Northeast Complaint

By Sam Mintz

FERC on Thursday dismissed a complaint from RENEW Northeast that had alleged that ISO-NE has "undue preference" for gas generators in its capacity accreditation and operating reserve rules (*EL22-42*).

The complaint from March of last year argued that ISO-NE doesn't adequately take into account the uncertainty of natural gas supply in the region, particularly in winter, and that it therefore harms almost every other type of generation. (See *Renewable Groups Challenge Gas 'Preference' in ISO-NE Rules*.)

The complaint has been closely watched in New England, and FERC received many comments on both sides of the argument.

Ultimately, the commission found that RENEW failed to meet its burden under Section 206 of the Federal Power Act to show that the existing tariff is unjust and unreasonable.

Specifically, FERC wrote in its dismissal order that RENEW "failed to establish that gas-only resources are not similarly situated to generators with fuel on site."

As for the complaint's points on operating reserves, FERC noted that, contrary to what RENEW claimed, the ISO-NE tariff doesn't require any resource to "have a known and measurable fuel supply and verifiable means of delivering upon real time dispatch."

But in dismissing the complaint, FERC also called on ISO-NE to step up.

"We urge prompt action by ISO-NE on reforms, including capacity accreditation if deemed appropriate, to address these reliability concerns," the commission wrote, adding that it is planning another forum on winter reliability issues in New England for June.

ISO-NE spokesperson Matt Kakley emphasized that the grid operator is continuing to work on updating its capacity accreditation rules through the stakeholder process.

"We're pleased that FERC dismissed this complaint. To date, the region's markets, including the capacity market, have achieved their primary reliability objective, but an overhaul of the capacity accreditation process is critically important as the region transitions to the future grid," he said in a statement.

"To that end, ISO New England and stakeholders have been working on this issue for more than a year, with plans to file a proposal with FERC later this year. With this complaint formally dismissed, ISO New England and others can now engage with FERC commissioners and staff, benefiting from their views and expertise as the region navigates this important process."

Clements' Concurrence

Commissioner Allison Clements went a step further than the rest of the commission. In a forceful concurrence, she wrote that she believes the ISO-NE tariff is in fact unjust and unreasonable, even though the commission had to dismiss RENEW's complaint because of what she called a "pleading error." And she called on FERC to take action itself.

"In the face of clear evidence that ISO-NE's rules fail to ensure the supply of resources when they are most needed, in my view the commission has a duty to take action to ensure grid reliability," Clements wrote.

Clements noted that everyone, including ISO-NE, agrees that the region faces gas delivery constraints that can threaten energy security, especially during extended extreme winter weather.

"Given this apparent agreement that ISO-NE's rules are failing to assess the reliability of resources when they are most likely to be needed, in my view the Commission has a duty to fix the problem via action pursuant to section 206 of the Federal Power Act," Clements wrote. "We cannot stand idly by as the region heads toward yet more winters for which it is not adequately prepared."

Mystic Generating Station north of Boston | *Shutterstock*

And she also suggested that she is wary of what ISO-NE might put forward in its formal capacity accreditation process.

"In my time at the commission, thus far it has accepted almost every significant capacity accreditation proposal put forward by an RTO or regional framework," she wrote. "My view has been that some of these proposals met the requirements of the Federal Power Act, while others did not.

"As these decisions mount … they contribute to a slow but steady erosion of the commission's bedrock legal standard that rate proposals must be just and reasonable and not unduly discriminatory," Clements wrote. ■

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Eversource Still Eyeing Offshore Wind Sale

OSW a Drag on Earnings Despite Record Profits; Unitil Sees Gain in 2022

By Sam Mintz

Eversource's 2022 earnings were hit by continued uncertainty over its offshore wind portfolio despite record profits, the company said in a call with analysts on Feb. 14.

The New England utility is performing a "strategic review" of its 50% stake in the South Fork Wind Farm, Revolution Wind and Sunrise Wind projects, which could lead to a sale of the assets, all of which are still under development.

"While our longer-term total shareholder return compares favorably with our peers, our 2022 return was disappointing," CEO Joe Nolan said. "We understand that much of that is related to the uncertainty over our offshore wind investments. We expect to resolve that uncertainty in the coming months as our strategic review progresses."

The company had originally planned to finish the review by the end of 2022 but now says it will be done by the second quarter of the year.

"I'd like to move at a good pace, but this is very complex and … folks need to understand that any buyer of these assets is going to want to do significant due diligence," Nolan said.

But there is "significant interest in the lease here as well as the projects," he said.

"We are going to get a fair price for these assets," he added. In the meantime, work on the projects is moving ahead.

Despite earning a record $1.4 billion last year, an increase of 15% from 2021, the company missed Wall Street estimates, reporting adjusted earnings of $4.05/share for the full year and 92 cents/share for the fourth quarter.

Wind turbines off of Block Island in Rhode Island | *Shutterstock*

Nolan said that Eversource's customers should see reductions to their bills soon as mild winter weather has reduced consumption and eased gas prices.

"For most of our electric customers, lower power supply costs will start to be reflected in bills in July," he said.

Unitil

Unitil, which serves customers in Massachusetts, Maine and New Hampshire, had a strong 2022, beating estimates and earning $41.4 million, up $5.3 million (24 cents/share) from the previous year.

"The earnings growth reflects higher distribution rates, including recoupment associated with the New Hampshire rate cases, partially offset by higher operating expenses," CFO Robert Hevert said.

Unitil's adjusted gross margin increased by more than $12 million thanks to higher rates, colder winter weather and customer growth; the company added 425 new customers on the electric side and 855 for gas.

"2022 certainly had its challenges. Ultimately, we were able to overcome these challenges and finish the year strong," CEO Thomas Meissner said. ■

MISO News

MISO Data Show Steep Gas-fired Outages During Winter Storm

By Amanda Durish Cook

MISO told stakeholders last week that as much as 23 GW of natural gas-fired generation was unavailable during the December winter storm, accounting for almost half of the grid operator's forced outages.

Staff said during an Entergy Regional State Committee meeting that forced outages reached 50 GW during the last two days of the Dec. 22-24 storm, up from 30 GW during the first day. Natural gas generation outages comprised 23 GW on Dec. 23 and 22 GW on Dec. 24, up from the 9 GW on Dec. 22. Forced coal-resource outages varied between 13 and 16 GW during the storm.

The MISO footprint's demand hit a likely winter peak of 107 GW on Dec. 23. Demand in MISO South peaked at 32 GW on Dec. 23, nearly matching the South's record of 32.9 GW set last June.

Staff said gas supply availability issues ultimately tipped the system into emergency procedures on Dec. 23 as they tried to maintain exports to neighboring regions. The maximum-generation emergency lasted for three and a half hours, forcing MISO to call up 1.2 GW of load modifying resources.

MISO's director of operations risk management, Jason Howard, told the ERSC that pipeline issues and fuel availability, not insufficient weatherization measures, contributed to the unplanned outages. He said staff are working to quantify operations data to better anticipate future winter storms.

In a blog post, Paul Arbaje, an energy analyst with the Union of Concerned Scientists, *called* the level of outages "troubling" and "equivalent to more than a third of the capacity that should have been available."

MISO's operations team drew parallels between this storm and the February 2021 severe-weather event. Howard said although the storm arrived earlier than staff predicted, the severe weather played out as expected. Staff said "abnormally high load forecasting errors" occurred because of a lack of historical data for "similar extreme conditions in December."

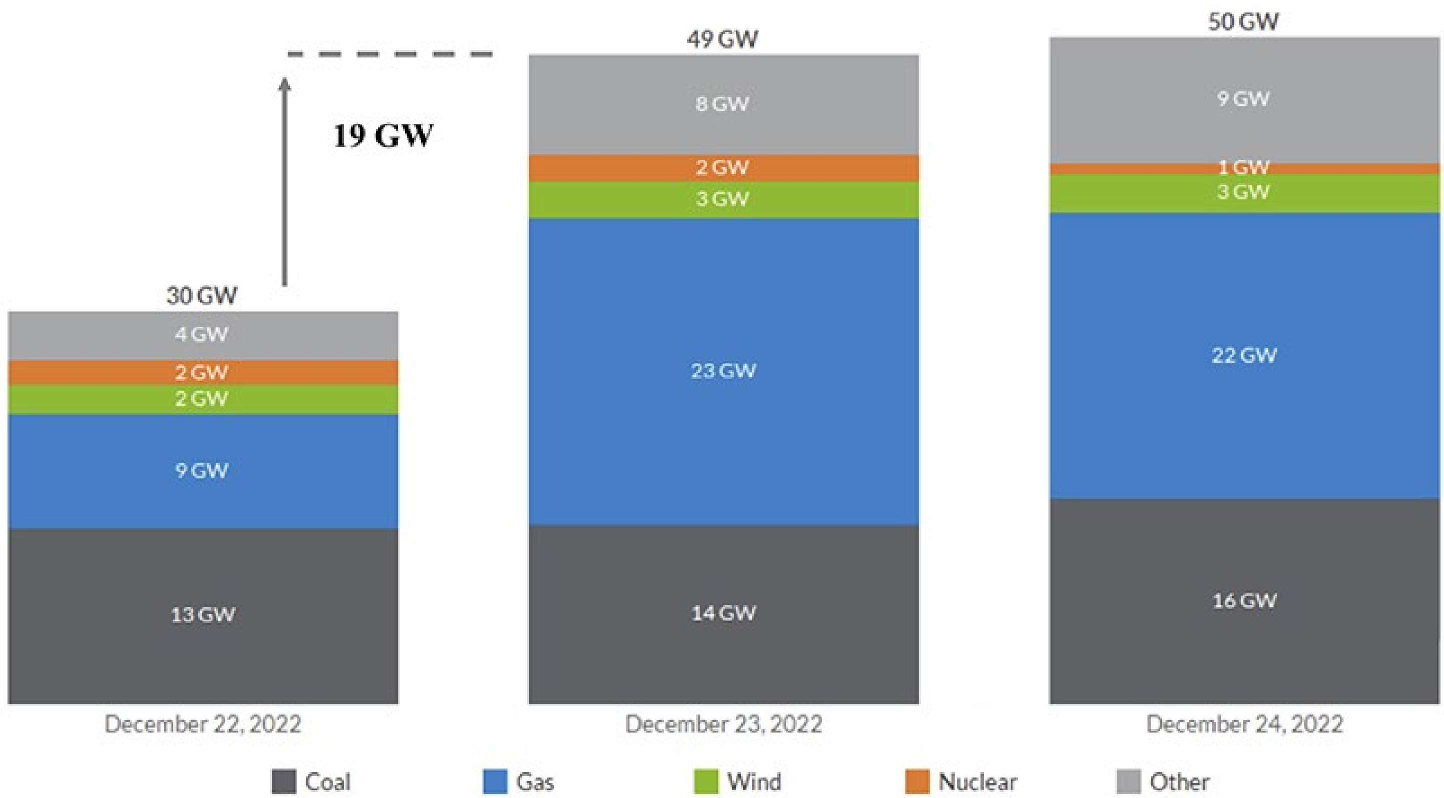
Howard said the storm's impact over most of the continental U.S. caused MISO and the industry to "really struggle" in gauging demand.

The grid operator's exports pushed electricity served to 111 GW on Dec. 23. "MISO consistently exported power to southern neighbors with a maximum value of nearly 5 GW," Howard said. (See *MISO Actions During December Storm Spark Debate*.)

The RTO said it honored a request to tamp down flows by 1,500 MW across its Midwest-to-South transfer constraint during the Dec. 23 morning peak, which produced emergency conditions in MISO South and a recall of non-firm exports. MISO can normally flow 3,000 MW south and 2,500 MW north across the transmission constraint, part of an agreement with its neighbors.

Scott Wright, executive director of resource adequacy, said because it's becoming more unpredictable to respond to system operations, MISO has expanded Resource Adequacy Subcommittee meetings into two-day affairs. Staff will use that time to define essential resource attributes, create a new accreditation process for non-thermal generation and design a sloped demand curve for the capacity auction.

"We're exploring with a conviction that we can do something," Wright said. ■



MISO unplanned generation outages Dec. 22-24 | *MISO*

MISO News

FERC OKs Changes to MISO Retirement Studies

Generation Owners Must Give more than 1 Year's Notice

By Amanda Durish Cook

FERC on Feb. 10 ruled that MISO generation owners must now give a year's advance notice to the grid operator before they can retire or suspend resources.

The commission approved MISO's request to double the amount of time it has historically required GOs to submit the notices under Attachment Y of the tariff, effective Feb. 13 (*ER23-630*).

The RTO's requirement that notices be submitted four full quarterly study periods in advance is just one piece of a more rigorous generation-retirement proposal. The grid operator will now conduct retirement reliability studies in batches on a quarterly basis and include extra analysis of thermal, voltage, stability and import limitations. Staff will also halve the time, from 75 to 150 calendar days, that they've allotted themselves to notify GOs whether their resources are needed for reliability purposes. (See *MISO to File More Stringent Generator Retirement Study Process*.)

MISO said it needs the additional notice to better analyze an anticipated slew of retirement requests. FERC agreed.

"As MISO explains, it expects to continue receiving a substantial amount of Attachment Y notices for generator suspensions and retirements," the commission wrote. "We find that the revisions will enhance the study process by allowing MISO more time to conduct the Attachment Y study that is needed to assess whether the reliability of the MISO transmission system is impacted by specific unit suspensions and retirements."

FERC's order also stimulated debate over whether the RTO should share some details of the confidential retirement notices it receives.

The footprint's industrial customers asked FERC to require more transparency from MISO about its members' retirement plans, saying the grid operator is "falling short of promoting full and robust transparency that enables forward market signals regarding generation suspensions and retirements for resource adequacy and transmission planning."

The RTO should immediately and publicly disclose Attachment Y notices it receives so utilities can make timely plans for new generation or demand management, the customers said. FERC said the request was beyond the scope of the proceeding.

Commissioner Allison Clements said that though she ultimately agreed with the decision, the secrecy surrounding MISO generation retirements might need some loosening. She said the extended-notice requirement could lead to GOs keeping their suspension and retirement plans under wraps longer.

"Transparency in this context requires a balance between generation owners' desire for confidentiality and the consumer benefits of earlier notice to allow market forces and planning processes to efficiently respond to generation supply changes," she wrote. "However, I am not convinced that MISO's current confidentiality provisions strike that balance appropriately."

Clements encouraged MISO and its stakeholders to discuss whether "more timely public notice of forthcoming suspensions and retirements is feasible."

"The primary basis for MISO's proposal in this proceeding is that the number of generator suspension and retirement requests has substantially increased in recent years, and MISO expects that trend to continue. This means that potential negative effects of insufficient transparency will only grow as the fleet transition continues," she said. ■

Ameren's Rush Island coal plant in Missouri is currently online past its planned retirement date to maintain MISO grid reliability. | *Ameren*

MISO News

FERC Affirms MISO's Seasonal Auctions, Accreditation

By Amanda Durish Cook

FERC on Thursday rejected two rehearing requests over MISO's seasonal capacity auction and availability-based resource accreditation, clearing the way for the RTO to conduct its first seasonal auctions in April.

The commission affirmed its previous decision that the seasonal, availability-based accreditation will incentivize availability and more accurately represent when generating units contribute to resource adequacy (*ER22-495*).

Commissioner Allison Clements, as she did in FERC's original order last year, disagreed with MISO's accreditation inputs, saying it "glosses over MISO's failure to adequately justify key details in its proposal."

Clements zeroed in on what she called "two of the most problematic design flaws": MISO's selection of resource adequacy hours that allow resources up to 12 hours to be counted in its operating reserve margin calculation, and the 24-hour lead time before resources are excluded from being assumed as available during those hours.

"In defense of its position, the only explanation MISO gave is that its choice of a 12-hour lead time was better than an alternative of 24 hours, which would have included even more resources incapable of delivering capacity when needed," she wrote in a concurring opinion. "But the Federal Power Act is not a 'Price is Right' showcase showdown, and the fact that a proposed rate is closer than an unjust and unreasonable option does not demonstrate it to be just and reasonable. One hundred dollars

We Energies has delayed retirement of four units at its Oak Creek generating site in southeast Wisconsin until 2024 and 2025. | *We Energies*

MISO News

for a gallon of milk is not a fair price, and the fact that $50 is a better alternative does not make it reasonable."

Clements said MISO's decision to credit resources that take up to a full day to start up will lead to extending credits for resources that are ineffectual during reliability issues.

"Incredibly, while MISO's only defense of using 12 hours as the lead time threshold for including resources in its calculation of operating margin is that doing so is more accurate than using a 24-hour lead time, it proposes to use the even-less-accurate 24-hour lead time when determining which resources get credit for delivering capacity," she said.

FERC last year approved the grid operator's request to conduct four seasonal capacity auctions, with separate reserve margins, and apply a seasonal accreditation mostly based on a thermal generating unit's past performance during tight system conditions. The expected and historical tight conditions are dubbed "resource adequacy hours," covering 65 hours during the year when resource availability is less than 25% of operating margin.

Louisiana and Mississippi regulators, Consumers Energy, Entergy, DTE Energy and Alliant Energy sought rehearing of the order's accreditation portion. They said a harsher accreditation based on risky hours that can't be predicted with certainty will result in fluctuating accreditation values, undue penalties to generation and won't reflect MISO supply fundamentals. (See *MISO's Seasonal Capacity Proposal Opposed at FERC*.)

DTE and Alliant accused the commission of "cursorily sweeping aside" concerns over accreditation instability. They said the accreditation framework could potentially cause about a "ten-fold increase in year-to-year accreditation volatility for some market participants" and could cause members to overbuild generation on the MISO system.

Entergy noted that according to the RTO's own analysis, a quarter of all market participants' total accredited capacity will experience a standard deviation between 7.7% and 15.5% from one planning year to the next in the spring season. Entergy said that translates into a 20% chance that a market participant's total accredited capacity will "undergo a year-to-year change of 20%."

The utility said a resource can experience "a significant reduction" in accredited capacity if it is unavailable during "even one or two days." Mississippi and Louisiana agreed that the design will cause "large swings" in accreditation year over year.

Before last year, MISO accredited its thermal resources annually based on the asset's historic three-year equivalent forced outage rates.

The commission was unpersuaded by the arguments and said the new accreditation's benefits still stand to outweigh the small amount of aggregate volatility it introduces across planning resources' capacity values.

FERC said the accreditation will lead to "increased accuracy, increased confidence in generator availability during high-risk hours, better coordination of resource outages and stronger incentives for resources to be available in times of need."

The commission disagreed with a coalition of clean energy organizations that said thermal resources shouldn't have a different accreditation framework from renewable resources. It said resource classes can be accredited using different methods.

The clean energy groups also took issue with MISO's response should a season not have at least 65 resource adequacy hours. The grid operator will use resource performance data from other high-risk hours throughout the year as a "backfill" to ensure there are 65 resource adequacy hours.

They also said MISO's proposal to top off the risky hours to make sure it meets a minimum 65 hours, or 3% of a season, "creates an artificial profile for these resources and assumes risk in a season during hours where there are none." FERC responded that maintaining a minimum target of hours to base accreditation upon "mitigates the volatility concerns."

The commission also supported MISO's 120-day advance notice requirement for planned generator outages; a capacity replacement obligation for resources on planned outages lasting longer than 31 days; and the RTO's plan to treat offline resources with lead times greater than 24 hours as unavailable during resource adequacy for accreditation purposes.

It resisted calls to delay the seasonal launch until the 2024-25 planning year to let market participants get their bearings in the new environment. FERC said market participants have attended stakeholder workshops that warned of the change as far back as 2019.

FERC's decision arrives as MISO may revise the availability-based accreditation method. The grid operator wants to adjust unit-level accreditation by a capacity value determined by loss-of-load expectation rather than its existing unforced-capacity values that rely on forced outage rates.

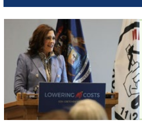
The design would apply to all resources and require edits to the new availability-based design. MISO currently uses a unit-level effective load-carrying capability calculation based on a peak hour contribution for wind resources. (See *Stakeholders Cry Foul on MISO's Resource Accreditation Pivot*.)

Clements contended that FERC violated the Administrative Procedure Act because it did not respond to arguments that many resources with nearly a full day's startup time cannot maintain reliability when they're offline during resource adequacy hours.

She found it "laudable" that MISO is seeking to improve "its outdated capacity accreditation framework. "

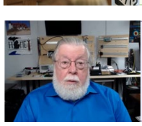
"It is clear that ... today's markets must be designed to address increasingly complex reliability challenges. Although MISO's proposal fell short of the mark, this does not suggest that changes to MISO's resources adequacy rules are not appropriate. To the contrary, further changes appear necessary," she said. ■

Midwest news from our other channels



Environmentalists Applaud Whitmer Budget on Climate Change Issues

NetZero Insider



RF Panelists: Executive Buy-in Key to CIP Success

ERO Insider

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

Energy Tech Group Pans Duke Indiana's Planned Gas Plant

Advocacy Group Suggests Clean-energy Portfolio Instead

By Amanda Durish Cook

A trade association representing emerging energy technologies is criticizing Duke Energy Indiana's proposal to build a natural gas power plant, saying a greener collection of solar, wind and storage resources can annually save customers several million dollars.

Advanced Energy United (AEU) released a *report* in February assessing alternatives to Duke Energy Indiana's (NYSE:DUK) 2021 *integrated resource plan* that proposes to build a 1,221-MW combined cycle plant by 2027. The clean-energy advocacy group tapped consulting firm Strategen to assess Indiana's changing market dynamics and develop a clean-energy portfolio to "match or exceed the energy and capacity" from Duke's proposed gas-fired plant.

Strategen and AEU concluded that a combined 2.9 GW of energy from wind (1,600 MW), solar (1,300 MW) and four-hour battery storage (900 MW) could save ratepayers $68.5 million in 2027. AEU said it anticipates savings in subsequent years will be even higher.

The advocacy group said last year's Inflation Reduction Act changes the playing field for the resource transition. It said its suggested portfolio can provide equivalent energy and capacity more cheaply than the cost of a large gas plant. The group added that its economic analysis of the two options included potential excess energy sales and market purchases.

Duke said in its IRP that a new gas plant would avoid "committing to dramatic resource changes prematurely, preserve its decision-making flexibility going into the 2024 IRP analysis, and shield customers from undue cost increases in the near-term."

"Duke's assumptions from 2021 are outdated," AEU said. "Market trends and recent federal action to extend energy tax credits have dramatically shifted the economics of various energy resources. This created a need to revise current and future utility plans so that benefits can flow to Hoosiers."

According to the report, the Duke gas plant would generate 6,014 GWh during 2027 while the renewables portfolio will churn out 7,984 GWh and likely require 961 GWh of imports. Economic analysis pinned the clean energy portfolio at $227 million in 2027 and the gas plant at $274 million, accounting for capital expenditures, fuel costs and fixed and variable operations and maintenance costs. Strategen said it also factored in revenues from selling excess energy, which the clean energy portfolio has more potential for.

The firm said its gas plant estimates don't include the possible carbon capture and sequestration equipment that Duke may need to install to reach its 50% carbon-reduction goal by 2030 and net-zero carbon emissions by 2050. It also didn't put a number on the cost of converting the plant to green hydrogen.

"This analysis is conservative and understates the potential economic value of the clean energy portfolio because it is only considering the energy revenue when matching profiles with the [combined cycle plant]," Strategen said. "If allowed to operate purely economically, the battery storage would see added revenue by arbitraging energy to periods of high prices, not just when the renewable generation is short."

AEU noted that volatile gas prices may make the gas plant a riskier bet. It said Duke studied a scenario in its IRP where gas prices are so high — Duke kept the fuel price forecasts confidential — that building a new plant would be uneconomic.

The advocacy group asked that Duke re-evaluate its plan to invest in the plant and to "consider further investment in clean energy resources through the added benefit of the IRA tax credits."

Duke Disputes Clean Portfolio Savings

In an emailed statement to *RTO Insider*, Duke said it's in the process of updating its IRP to reflect the IRA, new guidance from MISO on generation planning, and the changing costs of technology and commodities. The utility noted that it's holding a third public session on the IRP update Feb. 27.

Duke said AEU's report relies on generic cost data which "may not always capture the full costs" and doesn't match the real market bids that it received in *request for proposals* issued last year. It said when it updated AEU's proposal for current conditions in Indiana, it immediately found the clean energy portfolio to be more expensive.

The utility said the portfolio is "not a realistic plan" because it requires Duke to site large-scale renewable projects that need thousands of prepared acres within six years.

A Duke Energy Indiana solar farm near Bloomington, Ind. | *Duke Energy Indiana*

"Generation diversity is essential and a strength, and we expect our updated plan will be diverse and include a significant amount of renewables as well as natural gas resources that can be dispatched when needed, regardless of weather conditions," Duke said. "Including a moderate amount of natural gas in the resource mix positions us to retire coal plants earlier and add more renewables on our system until new, economical carbon-free technology arrives."

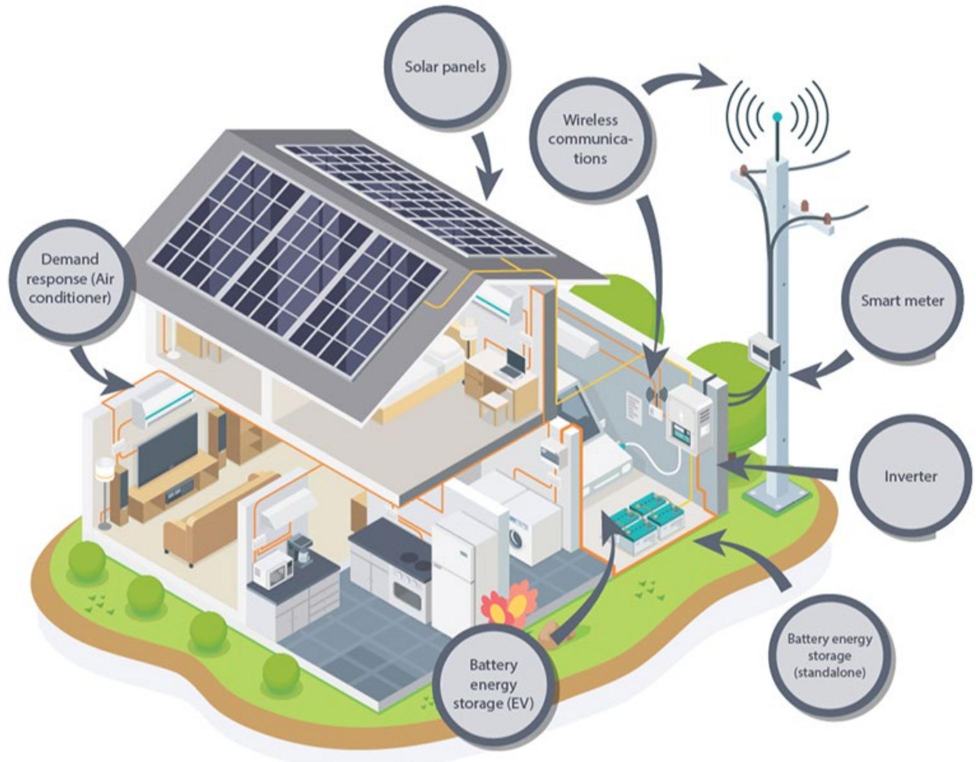
The utility added that it's simply too risky to substitute a "core" on-demand resource with a generation mix that relies on solar, wind, four-hour storage and power markets.

"We have to plan in a way that ensures reliability and self-reliance and is not overly reliant on the weather and power markets," the company said. "We are making the largest transition from coal-fired power in the state, and the renewable energy we add will be the largest addition of any of Indiana's utilities. We have to do this right. We have to transition in a way that ensures reliability and affordability for customers as well as cleaner energy." ■

NYISO News

NYISO Promises to Lower DER Minimum Capability in Future

By John Norris



Distributed Energy Resources (DER) Around the Home | *Cummins Inc.*

The NYISO Business Issues Committee on Wednesday voted to recommend that the Management Committee approve *proposed* tariff revisions to its participation model for distributed energy resource aggregations after the ISO *committed* to revisiting its unpopular 10-kW minimum for individual resource participation.

Stakeholders continued to express concern about the proposal, particularly the 10-kW rule, but were assuaged when NYISO promised it would re-evaluate "the ability of small facilities to provide wholesale market services as part of an aggregation" and look to "propose a set of market rules for small facilities that enhance grid reliability and resilience, reduce consumer costs, and lower barriers to entry for small DER."

The 10-kW rule is perhaps the most controversial among a slate of revisions intended to integrate DER aggregations into NYISO's markets. Although its model was approved in 2020, staff identified more changes they deemed necessary as they worked on implementing it. The ISO has said the rule is necessary while it gets used to integrating aggregations, as staff could be overwhelmed by so many smaller resources. (See *NYISO 10-kW Min for DER Aggregation Participation Riles Stakeholders*.)

Aaron Breidenbaugh, director of regulatory affairs at CPower Energy Management, said he understood ISO concerns about being potentially overburdened by thousands of small-scale DERs, but he still would have preferred that "some level of flexibility was built into the tariff" to allow future changes without having to go through a "multi month process" that is required to make revisions.

Rana Mukerji, NYISO senior vice president, responded that the ISO's "intention is to work with [stakeholders] to find rules where we can accommodate all resources." NYISO is "far ahead of peer ISOs and RTOs on comprehensive DER implementation," leaving plenty of time to resolve these issues, he said.

Breidenbaugh also mentioned that the two planned stakeholder outreach sessions focused on DER may not be enough to address these issues.

Four-Control-Area-Participation	PJM	ISO-NE	Quebec	Ontario	Totals
Initial Values (TTC Summer Ratings)	1450	1400	1690	1950	6490
Grandfathered Rights*	1080	0	1110	0	2190
Individal Limits (above GF)	193	250	39	268	750
Simultaneous Limits (above GF)	58	75	11	80	224
Final Values **	1138	75	1121	80	2414

Final Import Rights Results for 2023-24 Capability Year | *NYISO*

Michael DeSocio, NYISO director of market design, responded that those meetings "are meant to kick us off and figure out how to organize future discussions." Mukerji followed up with saying that the ISO has "administrative burdens that we need to overcome to integrate an aggregation with very small resources," so it is critical that "stakeholders actively participate to help [NYISO] figure out" how to best resolve DER implementation questions.

NYISO will seek MC approval of the proposal this Wednesday. If the proposal is approved by FERC, NYISO will accept customer registrations for aggregators in mid-April, and start open enrollment of DER and aggregations in early summer, when the revisions are expected to become effective. It anticipates DERs being dispatched approximately 90 days after they have applied or whenever the ISO completes mandatory workflow reviews.

The ISO also told stakeholders they could attend two training sessions: one dedicated to DER onboarding and market participation, and one on operations that includes an overview of the participation model and operation of the Grid Operations Communication Portal. ■

NYISO News

NY PSC Approves 62 Tx Upgrades Totaling 3.5 GW

$4.4B Plan Meant to Ease Upstate Bottlenecks amid Energy Transition

By John Cropley

The New York Public Service Commission on Thursday approved 62 transmission upgrades with a combined capacity of 3.5 GW and an estimated cost of $4.4 billion.

The projects in three upstate regions are needed to loosen existing constraints in preparation for the state's transition from fossil fuel-generated electricity to substantially larger amounts of clean renewable energy, according to the commission.

The price tag is only an estimate, and the final cost could range anywhere from $3.3 billion to $6.6 billion, which is a standard range of uncertainty for such projects, said Elizabeth Grisaru, deputy director of the Department of Public Service's Office of Electric, Gas & Water.

The resulting monthly increase in customers' bills could range from 3% to 16%, though success with the projects would prevent curtailment risk charges being passed from generators to utilities to ratepayers, she said.

The large price tag — and the fact that it is only one of many costs to be borne by ratepayers through the clean energy transition — gave some commissioners pause, but the majority voted for it.

The 62 upgrades are planned by Central Hudson Gas & Electric, National Grid, New York State Electric & Gas and Rochester Gas and Electric. The projects are focused in three areas of concern: the Hudson Valley and Mohawk Valley, extending south and west from Albany; the North Country, from the western Adirondacks to Lake Ontario and the Canadian border; and the Southern Tier, along the Pennsylvania border.

The utilities said there is 689 MW of existing solar and wind generation in these areas and 3,529 MW in some stage of development.

The work will be completed through the coming decade. Costs will be allocated across ratepayers statewide, as the benefits of decarbonization will extend to all New Yorkers.

Grisaru told commissioners that the projects were a result of the state's Climate Leadership and Community Protection Act (CLCPA), the landmark 2019 law that codified decarbonization goals including 70% renewable energy by 2030. The concurrent transition to electric vehicles and all-electric buildings will create added power demand statewide.

Passage of the Accelerated Renewable Energy Growth and Community Benefit Act led the PSC in May 2020 to start a proceeding to plan the transmission infrastructure needed to accommodate these changes.

The three upstate regions were identified as problem zones in September 2021, and the utilities were directed to submit plans for upgrades.

Grisaru said the 62 projects are a snapshot estimate by the utilities, circa late 2021, of their future needs, but more generation projects have gone into development since then, and further transmission upgrades may be needed. Based on this, the package of 62 upgrades is a very conservative response to present and potential future needs, she said, with little risk of over-construction.

"I'm happy to see this project before us today," PSC Chairman Rory Christian said. "We understand that to successfully decarbonize, we need to have a robust transmission system, and I'm encouraged that these investments will not only help us achieve that goal but help secure New York's role as a leader in clean energy going forward."

NYISO has highlighted the need for grid upgrades, and it did so again after Thursday's vote.

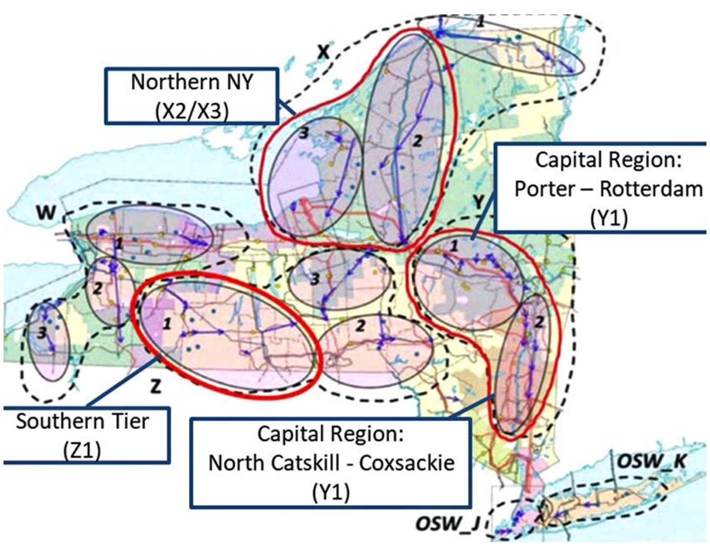
"As stated in the NYISO's 2021-2040 System & Resource Outlook, significant investments in generation and transmission projects are needed now to maintain the reliability and resiliency of our grid moving forward," ISO spokesperson Kevin Lanahan said via email. "We'll continue to work closely with elected officials, regulators and stakeholders to keep the grid working for all New Yorkers."

The order was approved 5-2, with Commissioners Diane Burman and John Howard opposed. Both agreed with transmission expansion, but not with the mechanism by which the cost is being reviewed and allocated. They thanked Grisaru and her staff, however, for noting the uncertain cost of the upgrades.

Commissioner John Maggiore wished the state's progressive income tax could cover some of the cost, rather than all of it falling on ratepayers.

Commissioner James Alesi recalled the great delays and cost overruns with the Second Avenue Subway project in Manhattan and said he worried about the unknown future costs of CLCPA rollout, which is currently being estimated at $275 billion — about $14,000 per person, or $37,000 per household statewide.

The PSC has divided transmission upgrades that have been proposed to accommodate expanded renewable energy in the wake of CLCPA into two categories: Phase 1, which also incorporates safety and reliability considerations, and Phase 2, which solely to supports new resources. Thursday's order was the first Phase 2 approval by the PSC. ■



The areas circled in red contain power transmission bottlenecks that are targeted by a round of upgrades approved Thursday by the New York state Public Service Commission. | *New York state Public Service Commission*

NYISO News

Con Ed Yearly Earnings Continue to Rise

By John Norris

Consolidated Edison *released* its 2022 earnings report late Thursday night, showing that it earned $1.66 billion in net income ($4.68/share), about $300 million, or 23%, more than in 2021.

The increase was slightly more than that of 2021, which saw earnings increase by about 22%. (See *Con Edison 2021 Earnings Jump 22%*.)

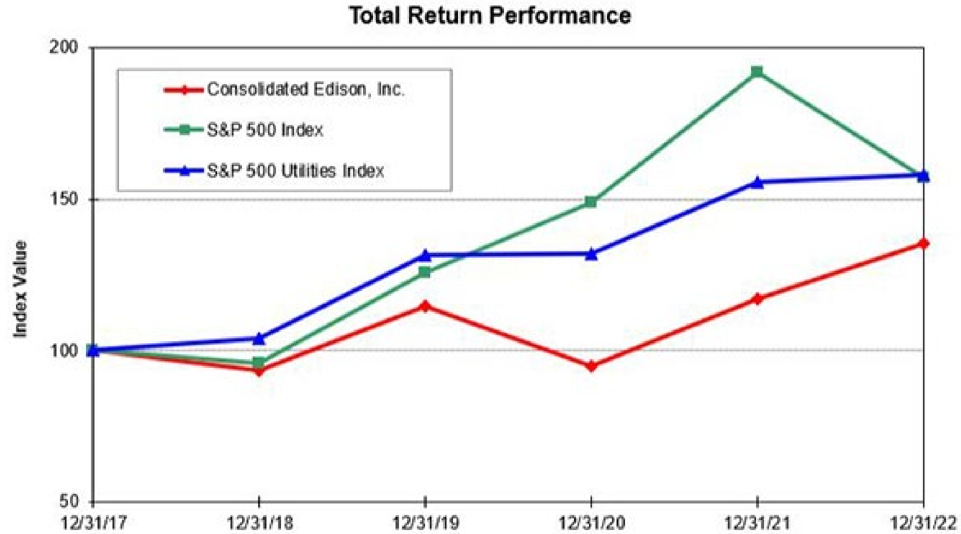
Earnings for the fourth quarter, however, were down about 15% from the same period in 2021: $190 million ($0.53/share), compared to $355 million ($1/share).

CEO Timothy Cawley said in a *statement* that "the great work of our employees and our customers' desire for a clean energy future enabled us to make tremendous progress in 2022 in energy efficiency, new [electric vehicle] charger installations and customer solar projects."

The New York-based utility, which services parts of New Jersey via Orange & Rockland Utilities, sold its Clean Energy Businesses (CEB) portfolio of 3,300 MW in renewable energy projects to RWE Renewables America in 2022. The deal is valued at $6.8 billion and anticipated to close near the end of the first quarter. (See *Con Edison to Sell Clean Energy Businesses for $6.8B*.)

According to its earnings report, Con Ed spent months considering "strategic alternatives" for the CEB but concluded that the transaction would allow it to "focus on our core utility businesses and the investments needed to lead New York's ambitious clean energy transition," Cawley said in a *statement* in October.

Con Ed intends using funds from the CEB sale to repay $1.25 billion of parent company debt in 2023, repurchase up to $1 billion of its common shares, forego common equity issuances in 2023 and 2024, and issue up to $900 million of common equity in 2025.



ConEd Return Performance | *ConEd*

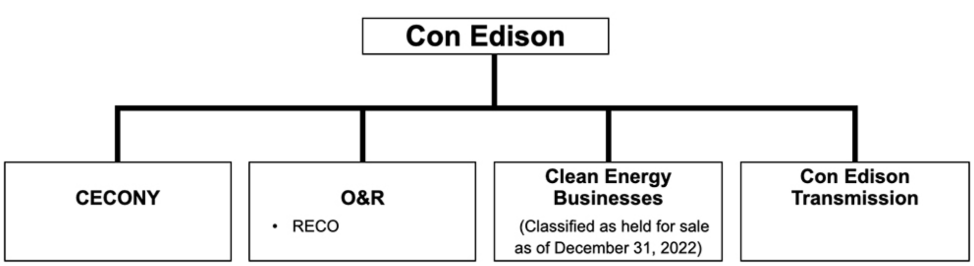
The company also issued $366 billion as part of the COVID-19 arrears assistance program, which the New York Public Service Commission created to help reduce the arrears balances of residential and small commercial customers struggling after the pandemic. Phase 2 of the program started in January, and Con Ed approximates that $392 million credit is eligible for the program.

Con Ed also *announced* on Wednesday that its customers installed a record 9,600 solar projects last year, which have the capacity to produce 89 MW.

The company expects 2023 adjusted earnings per share to be between $4.75 to $4.95 because of the anticipated CEB sale. It forecasts an average annual increase in peak demand over the next five years for electricity and gas to be approximately 0.6% and 1%, respectively.

Con Ed also plans to issue approximately $2.6 billion in long-term debt, including for maturing securities, during 2024 and 2025. ■

Consolidated Edison Building | *Beyond My Ken, CC BY-SA 4.0, via Wikimedia Commons*



ConEd Corporate Structure | *ConEd*

PJM News

FERC Approves PJM Quadrennial Review

By Devin Leith-Yessian

FERC last week accepted a set of revisions to PJM's tariff that the RTO proposed through its Quadrennial Review of the parameters underlying its Reliability Pricing Model (RPM) auctions (*ER22-2984*).

The Feb. 14 order accepted all the changes sought by PJM, sanctioning a market design with a steeper variable resource requirement (VRR) curve intended to procure a smaller amount of capacity hewing closer to the reliability requirement. The new paradigm also switches the reference resource used to determine the cost of new entry (CONE) from a combustion turbine to a combined cycle generator.

"This Quadrennial Review proposal was developed with an unprecedented level of stakeholder input and appropriately reflected stakeholder priorities," PJM spokesperson Jeff Shields said in response to the order. "The new VRR curve is an improvement on the prior VRR curve, as it achieves a better balance between reliability and cost by procuring resources based on the reliability standard, thus meeting reliability requirements at a reasonable cost while incentivizing investment in new generation resources."

Steeper VRR Curve

Pointing to market simulations conducted by the Brattle Group, PJM said the existing VRR curve over-procures capacity and results in an average loss-of-load expectation (LOLE) of one in 17 years, which it states is "significantly greater" than the target of one in 10. The new market design was simulated by Brattle to produce a LOLE of one in 14.

The new shape shifts the foot of the curve, the lowest point, about 2.2% to the left of the reliability requirement to "help prevent costly impacts of overestimations of net CONE, which would result in more reliability than expected," PJM said in its filings.

PJM also changed the calculation for setting the capacity price cap, the highest point of the curve, to be set at the greater of the gross CONE or 1.75 times net CONE. The shift away from the current cap set at 1.5 times net CONE is intended to address the possibility that market conditions could change in the gap between the Base Residual Auction's (BRA) and the delivery year and result in an underestimation of net CONE and therefore an under-procurement of capacity.

The PJM Power Providers (P3) protested the changes, saying that the steeper curve, combined with the other changes the RTO proposed, would result in increased volatility and compound the price impacts of each market design change. (See *PJM Defends Quadrennial Review Parameters from Generator Protests*.)

The Independent Market Monitor noted in its comments that the proposal moves closer to its recommendation of rotating the curve halfway toward a vertical demand curve, which would have created a much steeper curve. The Monitor's analysis found that the recommendation would have reduced the 2023/24 BRA's revenues by $406 million, or 18.5%. (See *IMM Offers Mixed Review of PJM Quadrennial Review Docket*.)

Forward-looking EAS Offset Calculation

The market design changes also include switching from using historical data to calculate energy and ancillary services (EAS) revenues to a forward-looking approach to calculating the EAS offset.

The change was supported by several envi-

PJM transmission line near Conowingo Dam | *© RTO Insider LLC*

PJM News

ronmental and public interest groups in a joint filing stating that a forward-looking EAS offset would be more responsive to an evolving resource mix, fuel prices and future market conditions.

The Monitor also supported the change, stating that the proposed approach reflects how investors evaluate the market and avoids overstated capacity market prices stemming from an EAS offset being based on historically low prices in the PJM markets as current and forward-looking energy prices have increased significantly.

In its protests, P3 said the use of futures prices would increase market uncertainty and volatility. By using proprietary data and models in its calculations, P3 also said that the proposal lacked transparency and limited market participants' ability to estimate how future EAS revenues would be determined.

In accepting the forward-looking approach, the commission wrote that it relies on the same data developers use to assess project viability and that prices from liquor futures markets produce prices reflecting future conditions.

"We find that PJM's proposed use of futures prices to calculate the EAS offset is just and reasonable because the record indicates that futures prices better reflect PJM market participants' expectations of future market conditions as compared to historical electricity prices," the commission said. "Indeed, P3 provides no evidence that market participants themselves use historical prices to predict future prices. PJM, on the other hand, supports its claim that market participants use futures prices."

The commission also said that this was in line with an "almost identical" that it approved in 2020 (EL19-58).

PJM had previously sought to shift to using futures data as part of a 2019 filing revising its reserve markets and received FERC approval the following year, but the commission reversed itself in 2022. In overturning the previous order, the commission said its reversal of the reserve penalty factor and operating reserve demand curve (ORDC) "undermined the fundamental basis" for its determination that the historic offset was unjust and unreasonable. (See *FERC Reverses Itself on PJM Reserve Market Changes*.)

Change to Combined Cycle Reference Resource

Shifting away from its longtime usage of combustion turbines as the reference resource, PJM proposed to use a combustion cycle generator as the resource type that is most likely to be constructed to meet a capacity shortfall in the future. The RTO noted that the last combustion turbine built in its footprint was in 2018, and the Monitor wrote that no "significant level" of capacity has been installed since 1999.

P3's protest stated concerns that using a combined cycle would come with a higher and more variable EAS offset. It said that higher profits in those markets could lead to a lower net CONE, lower relative capacity prices and ultimately less capacity clearing even if a higher supply is needed.

"Based on the record as a whole, we find P3's concerns to be overstated," FERC said. "As Brattle explains, perverse incentives will not be substantially different for combined cycle plants than for combustion turbines because both combined cycle plants and combustion turbines are usually operating as load approaches peak load, which is when energy prices are more sensitive to supply conditions."

Amortization Period

The commission also overruled a protest from J-Power USA stating that the amortization period used in the calculation of gross CONE doesn't take into account legislation that would shorten the lifespan of a generator, namely Illinois' Climate and Equitable Jobs Act (CEJA).

The company pushed for a shorter amortization in the ComEd locational deliverability area (LDA) to reflect the requirement that generators be carbon free by 2045, which the protest said would result in the early retirement of gas generators, including the combined cycle unit reference resource.

The commission noted that PJM stated it would be inappropriate to change the period for the ComEd transmission zone without changing the parameters for the rest of the CONE area and that CEJA contains a carveout to allow generators to continue operating outside the emissions requirement if deemed necessary for reliability.

Danly and Christie Reluctantly Concur

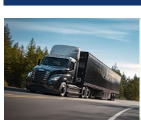
Commissioner James Danly wrote that while he is in agreement that the Quadrennial Review filing meets the requirements of Federal Powers Act Section 205, he believes that the protests to its provisions show that the commission should consider a broader examination of PJM's capacity market.

"The time is ripening for the commission to investigate whether the PJM rate construct (including the capacity market) is just and reasonable and not confiscatory," he wrote. But in this section 205 proceeding, I agree — reluctantly — that PJM has made the required showing that these piecemeal proposals are just and reasonable."

Commissioner Mark Christie also said that the larger functioning of the capacity market was the "elephant in the room" as the commission examined the Quadrennial Review.

"Moreover, we cannot ignore the events of last Dec. 24 and 25: Winter Storm Elliott," Christie said. "One of the common criticisms over the years has been that the PJM capacity market procures too much capacity, yet during at least two recent extreme weather events — the polar vortex of 2014 and Winter Storm Elliot last December — PJM reportedly came very close to ordering rotating outages. … My point in this concurrence is not to analyze, favor or criticize earlier changes to the capacity market construct or propose new changes; my point is a larger one: that these events raise important broad questions about this capacity construct's efficacy." ■

Mid-Atlantic news from our other channels



NREL Report Sees Role for Electric Trucks at Port of NY-NJ

NetZero Insider

NJ Governor Sets Out Accelerated Emissions Targets

NetZero Insider

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

PJM News

PJM EIS Announces New Hourly Clean Energy Certificates

By Devin Leith-Yessian

The subsidiary of PJM that manages its registry of clean energy certificates will next month release a new product broken down by the hour in which the energy was created, the RTO announced last week.

Ken Schuyler, president of *PJM EIS*, said no other registry of renewable energy credits (RECs) in the U.S. has created an hourly product, but he believes it's a road others are likely to follow to meet the needs of customers seeking increasingly granular data, particularly those striving to meet clean energy goals.

The certificates currently managed by the Generation Attribute Tracking System (GATS) that EIS operates include the generator location, emissions output, fuel source and date the generator went online. Each one represents 1 MWh and are produced based on the amount of power the facility produced in a given month.

The new credits will also include the output by date and hour.

"We recognize that customers are interested in more granular, real-time data that can be used to innovate new ways to incentivize clean energy," Schuyler said in an *announcement*. "Using the unique data offered by GATS, customers can make more informed choices about their energy use."

The more detailed certificates allow those with environmental targets to match their energy usage throughout the day to ensure the entirety of their power is provided by renewable or carbon-free generation, Schuyler said. Another application he identified is for buyers to target when they purchase credits to displace high-emitting generators during hours when marginal emissions are at their highest.

"The hourly data that we're making available is being made available so that they can make informed choices and accomplish their strategies, whatever that might be," he told *RTO Insider*.

Constellation Energy applauded the announcement, saying it enhances the ability for consumers to demonstrate that they are using carbon-free energy.

"This advancement is enabling companies like Constellation to offer a more complete range of products that help customers meet their sustainability goals," said Kathleen Barrón, Constellation's chief strategy officer. "As we work toward our purpose of accelerating the transition to a carbon-free future, we can provide this critical service for customers who want more clear and accurate data on their emissions impact, including producers of clean hydrogen who must demonstrate that they are using zero-carbon energy to qualify for new federal tax credits."

The company noted that it launched its own hourly carbon-free energy matching product last year, allowing customers to match their energy with regional carbon-free generation on an hourly basis. The new hourly certificates supplied by EIS will provide a "transparent and independent way to certify that they are meeting their clean energy goals."

Speaking on a panel during PJM's General Session in October, Brian George, lead of Google's energy regulatory and policy engagement team, said the company was shifting to procuring clean energy when and where it's needed, rather than focusing on the installation of additional renewable generation. In an email following PJM's announcement, he said the hourly data is central to the company's carbon-free energy goals. (See *PJM General Session Focuses on Clean Energy Transition*.)

"We welcome PJM's announcement to implement an hourly tracking mechanism. As a buyer of electricity in PJM with a goal to power our data centers with 24/7 CFE by 2030, hourly tracking is essential. We hope other RTOs and ISOs across the country will follow PJM's leadership," George wrote. ■

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PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Thursday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

RTO Insider will be covering the discussions and votes. See next week's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

As part of its consent agenda, the MRC will be asked to endorse:

B. proposed *revisions* to Manual 27: Open Access Transmission Tariff Accounting to conform to the settlement agreement approved by FERC in PJM's filing to change its administrative cost recovery charges (*ER22-26*).

C. proposed *revisions* to Manual 40: Training and Certification Requirements resulting from a periodic review.

Endorsements (9:10-9:20)

3. Manual 6 FTR Bid Limits (9:10-9:20)

PJM's Emmy Messina will *present* a proposal to increase the number of bids a corporate entity may submit into FTR auctions, alongside corresponding revisions in Manual 6: Financial Transmission Rights. The committee will be asked to endorse the proposed solution and associated manual revisions. (See "FTR Bid Limit Increase Endorsed Under Fast Track Pathway," *PJM MIC Briefs: Jan. 11, 2023*.)

Issue Tracking: *FTR Auction Bid Limits*

Members Committee

Consent Agenda (12:35-12:40)

As part of its consent agenda, the MC will be asked to endorse:

B. a proposed solution to implement the second phase of PJM's hybrid resource rules, along with corresponding tariff and Operating Agreement revisions. (See *PJM Releases Phase 2 of Energy Transition Study*.)

Issue Tracking: *Solar-Battery Hybrid Resources*

C. a proposal to revise PJM's day-ahead zonal load bus distribution factors and corresponding revisions to tariff section 31.7. (See "MIC Endorses Proposal on Hybrid Resources," *PJM MIC Briefs: Nov. 2, 2022*)

Issue Tracking: *Day-ahead Zonal Load Bus Distribution Factors* ■

— Devin Leith-Yessian

Exelon Earnings Highlight Investments to Comply with State Legislation

By Devin Leith-Yessian

Exelon leadership last week *charted* out the company's path to maintaining its growth targets while implementing its plans to comply with state environmental legislation.

"The Exelon team has proven it's ready to meet the challenge of leading the nation in its energy transformation, powering a cleaner and brighter future for our customers and our communities while creating value for our shareholders," CEO Calvin Butler said during the Feb. 14 earnings call.

Exelon *reported* a 27% increase in earnings for 2022, at $2.054 billion. Its fourth-quarter earnings of $432 million were nearly 40% higher than those in the fourth quarter of 2021.

The company saw 8.1% annual growth off its 2021 guidance midpoint and operating earnings of $2.27/share, exceeding guidance by 2 cents/share. The 2023 projection anticipates 5% earnings growth relative to the 2022 guidance and operating earnings guidance at $2.30 to $2.42/share.

Butler said the company completed its separation with Constellation Energy and has had a successful first year as a transmission-and-distribution-only utility.

"In 2022, Exelon showcased our ability as a pure transmission-and-distribution company to deliver on our financial and operational commitments," Butler said. "Because of the partnership with our customers and communities, Exelon is ready to lead the energy transition to a cleaner and brighter future."

Calvin Butler, Exelon | *Exelon*

CFO Jeanne Jones noted that the 5% growth expected this year is below Exelon's 6 to 8% target range between 2022 and 2026. Exelon is projecting its operations and maintenance costs being $100 million higher this year, which Jones attributed to one-time costs associated with the Illinois Clean Energy Jobs Act (CEJA), as well as information technology investments, cybersecurity enhancements and taking advantage of favorable weather to engage in corrective maintenance.

Commonwealth Edison filed its first multiyear rate plan and its grid plans to the Illinois Commerce Commission under CEJA, which calls for carbon-free energy generation by 2045. The plan's investments include bus reconfigurations, work overhead and underground infrastructure to support an anticipated 1 million electric vehicles by 2030, and converting 4-kV infrastructure to 12 kV. (See *Illinois Senate Passes Landmark Energy Transition Act*.)

"As Illinois progresses towards its decarbonization goals, ComEd is starting from an industry-leading position of strength," Butler said.

ComEd has also filed with the ICC to defer collection of 35% of the 2024 rate increase until 2026 to smooth the impact for customers.

Jones said carbon mitigation contracts are projected to save ComEd customers over $3 billion in energy charges between 2022 and 2027.

The company is also preparing to submit its multiyear plan with the Maryland Public Service Commission later this month, with proposed investments in line with the state's Climate Solutions Now Act. Jones pointed to the $50 million in school bus electrification incentives Baltimore Gas and Electric has offered Maryland school districts as the type of investments the utility is making. (See *Md. Climate Bills Become Law Without Hogan's Signature*.)

"Like Illinois, Maryland's Climate Solutions Now Act has set aggressive climate and decarbonization targets, creating an environment where utility action and investment is a key priority and for which multiyear planned frameworks are particularly well suited," Butler said. ■

Southeast

AEP, Liberty Utilities Try Again on Kentucky Territory Deal

By Amanda Durish Cook

American Electric Power and Algonquin Power & Utilities subsidiary Liberty Utilities have *filed* a fresh application with FERC seeking approval of AEP's Kentucky operations' sale to Liberty.

This time, the two utilities have added new commitments so the sale won't raise customer rates (*EC23-56*).

FERC shot down the sale in December, indicating more consumer protections were needed before the commission could give its blessing.

The utilities have since added more safeguards, including a five-year freeze on the current return on equity and 55% equity capital structure; a commitment from Liberty to maintain the same credit profile for five years; and a five-year cap on operations and maintenance and administrative costs at the 2022 rate.

AEP and Liberty also pledge to hold wholesale power and transmission customers harmless from any transaction costs for five years following the sale. The proposed transaction's other aspects remain unchanged.

The utilities are requesting an expedited review of the application and hope to the close the transaction by April 26. If they fail again to gain commission approval by then, termination rights kick in for the parties.

"When taken in total, these commitments will ensure that the transaction has no adverse effect on both Kentucky Power or Kentucky TransCo's individual rates and the rate for the AEP East zone," AEP and Liberty said in the filing.

The new sale application continues AEP's two-year effort to offload its Kentucky operations to Liberty. Late last year, the parties agreed to shave $200 million off the purchase price down to $2.646 billion. (See *AEP Accepts Lower Price for Kentucky Operations Sale*.)

AEP said the transaction's approval should bring an economic boost to retail customers in an "economically disadvantaged part of eastern Kentucky." It cited previously agreed-upon compromises at the Kentucky Public Service that include a $40 million fund to help offset volatile fuel rates for the remainder of the year; a $55 million, three-year rate holiday on collecting a Big Sandy nuclear plant decommissioning rider; a $43.6 million cut in regulatory charges collected from customers for storm costs; and a new Kentucky call center in the Kentucky territory.

"AEP and Liberty are committed to the sale and are requesting FERC's accelerated review of the application so customers in eastern Kentucky can begin benefiting from the transaction," AEP CEO Julie Sloat said in a statement.

Sloat said the sale is just one component of AEP's strategic plan. She said utility leadership remains dedicated to selling AEP's competitive renewables portfolio and conducting a review of its retail business as part of its equity financing plan and goal for a 6 to 7% long-term growth rate. ■

Implosion of a Big Sandy cooling tower in 2016 | *Independence Demolition*

FERC Rulings Diverge on Commercial Operation Deadlines

Commission Upholds 5 Orders

By Rich Heidorn Jr.

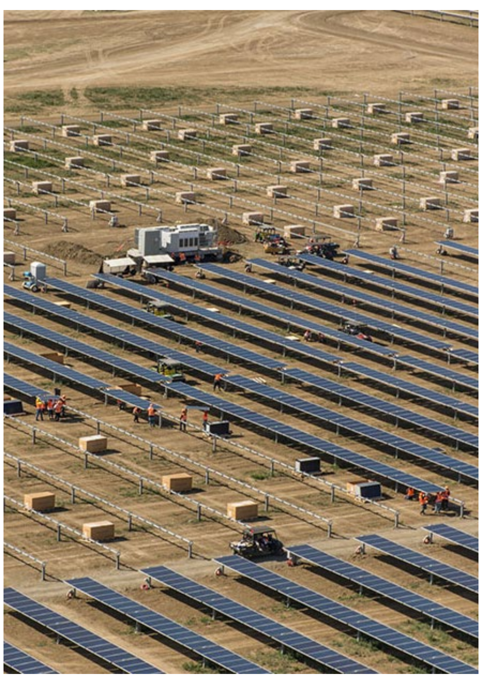
FERC granted an Oklahoma solar project a 90-day extension of its commercial operation deadline while rejecting an Illinois wind project's request for a waiver, saying the developer failed to make its case for relief.

The commission on Thursday granted Recurrent Energy's 120-MW North Fork Solar Project in Kiowa, Okla., a 90-day extension of its required commercial operation date (COD) (*ER23-737*).

North Fork's generator interconnection agreement with SPP and Western Farmers Electric Cooperative requires commercial operation by May 1, 2024, which was extended from the original COD of December 1, 2019. The company said it needed a 90-day extension, to July 30, 2024, to align the COD with the mechanical completion date provided by North Fork's engineering, procurement and construction (EPC) contractor and to allow a 90-day period between mechanical completion and the COD, as required under North Fork's power purchase agreement.

Neither SPP nor Western Farmers opposed the waiver.

North Fork said it has spent $7.7 million developing the project and expects to spend an additional $11 million by the time construction begins, including payments to the EPC contractor, developer fees and financing costs. It has secured land rights for 1,920 acres for the project, which will interconnect at Western Farmers' 138-kV Snyder Substation.



| Recurrent Energy

North Fork has a 15-year PPA with the Oklahoma Municipal Power Authority (OMPA) for the full output of the project. The PPA requires the project to reach commercial operation by May 31, 2024, so that OMPA can claim capacity credits for the summer of 2024. North Fork would be liable for liquidated damages if it misses the deadline.

"Accordingly, North Fork states that it is commercially incentivized to achieve commercial operation as soon as possible," FERC said.

North Fork said its EPC contractor has provided an estimated mechanical completion date of mid-March 2024, which would precede the initial synchronization and beginning of test sales.

Waiver Rejected

In a second order, the commission rejected a request by ZEP Grand Prairie Wind, a proposed 150-MW project in Illinois, to extend its COD from November 2025 to February 2027 because of delays caused by the COVID-19 pandemic (*ER23-137*).

ZEP's generator interconnection agreement with MISO and the city of Springfield, Ill., would be terminated if the project does not reach commercial operation by November 2025.

Developer UKA North America said it had recalled its land agents responsible for negotiating property rights for the project site and interconnection rights-of-way in response to the Illinois governor's March 2020 executive order requiring all non-essential employees to remain at home because of the COVID pandemic.

The company also cited supply chain problems that arose during the pandemic, saying key components that previously took nine to 12 months to receive are now taking 18 months or longer.

ZEP Wind said that it has spent more than $4 million on the project and obtained 100% site control and more than 85% of the transmission rights-of-way required. Nevertheless, it said will be unable to reach commercial operation by its 2025 deadline.

The commission said ZEP Wind "has not provided any details regarding whether any components for the project are delayed, the estimated time for their delivery, or whether and how any such delay affects its ability to achieve commercial operation by Nov. 15, 2025."

The commission said it would reconsider the waiver request if ZEP Wind provides more detail.

FERC on Thursday also upheld five prior rulings that had been subject to rehearing requests:

- The commission addressed arguments raised on rehearing of its Oct. 20, 2022, order accepting Henderson Municipal Power and Light as a transmission owner in MISO and allowing Henderson to recover its revenue requirement for transmission facilities (*ER19-776-002, ER19-809-002*). (See *FERC Rules Kentucky Muni Can Remain a MISO TO*.)
- The commission addressed requests for rehearing of its Sept. 9, 2022, order accepting two unexecuted generator interconnection agreements, which assigned to SPP interconnection customers the costs of a network upgrade (*ER22-2371-001, ER22-2372-001*).
- The commission rejected Tenaska Clear Creek Wind's request for rehearing of its Sept. 9, 2022, order, which found that the assignment of certain network upgrade costs was just and reasonable (*EL21-77-003*). The order also denied a motion for stay. (See *FERC Rules in Three SPP Disputes*.)
- The commission rejected a request for rehearing and clarification of its Dec. 16, 2022, order setting for hearing and settlement judge procedures issues raised in a complaint relating to the operation of Entergy's Grand Gulf nuclear facility (*EL21-56-001*). (See *Fifth Circuit Demands an Explanation from FERC on Long-Pending Grand Gulf Complaints*.)
- FERC sustained the result of its Oct. 7, 2022, order denying Southwestern Public Service's complaint alleging that SPP violated its tariff by setting the cleared energy award for SPS's Hobbs generating facility to zero when SPP settled the day-ahead market for Feb. 17, 2021 (*EL22-30-001*). ■

Company Briefs

Georgia Power Again Delays Vogtle Nuclear Plant

Georgia Power last week announced it is again delaying the projected startup for two new units at its Vogtle nuclear power plant, saying its share of the costs will rise by an additional $200 million.

Georgia Power said Unit 3 could begin commercial operation in May or June, pushing back from the most recent deadline of the end of April. The company also said Unit 4 will begin operation sometime between November and March 2024 after previously promising commercial operation by the end of this year.

In its earning call, the company said it will spend a projected $10.6 billion on construction costs.

More: *The Associated Press*

McDonald's Signs on for 180 MW of Louisiana Solar

McDonald's last week announced it has signed a power purchase agreement for 180 MW from the Prairie Ronde solar project in Louisiana.

Lightsource bp will finance, build, own and operate the facility. The output is equivalent to about 630 restaurants' annual energy demand.

Construction is expected to begin early this year with commercial operations starting in 2024.

More: *pv magazine*

Ford Halts Production of Electric F-150 for Possible Battery Issue

Ford last week announced it has halted production of its F-150 Lightning electric pickup truck because of a possible battery problem.

The company did not say what the battery-related issue might be, but the potential issue was discovered during pre-delivery inspections. The issue does not apply to trucks that are already at dealerships ready to be delivered or trucks already with customers.

More: *CNN Business*

Federal Briefs

Biden Names Brainard, Revesz to Administration

President Joe Biden last week named Lael Brainard, the vice chair of the Federal Reserve, as his new director of the National Economic Council.

Brainard is known for citing the financial risks posed by climate change and is expected to play a key role in the implementation of the Inflation Reduction Act.

Brainard's appointment follows that of Richard Revesz, an environmental lawyer, who last month became head of the White House Office of Information and Regulatory Affairs.

More: *The New York Times*

EPA: US GHG Emissions Saw Record Single-year Spike in 2021

U.S. greenhouse gas emissions rose 5.5% in 2021 from the previous year, an all-time year-over-year spike, but emissions were still below 2019 levels, according to a draft EPA report.

The agency found total emissions of 6,347.7 million metric tons in 2021, driven largely by increased auto emissions as driving rebounded in the second year of the COVID-19 pandemic. Fossil fuel combustion-related emissions increased 7% relative to the year before, while emissions from coal consumption rose 14.6%.

Despite the sharp increase compared to 2020, 2021 emissions from fossil fuel consumption were down 1.3% from 2019, while emissions from electric power were down 4% from 2019 to 2021.

More: *The Hill*

Judge Blocks Signal Peak Coal Mine Expansion

Ninth Circuit Court of Appeals Judge Donald Molloy last week tossed out an Interior Department decision that would have allowed Signal Peak Energy to expand a coal mining operation in central Montana.

In his ruling on Feb. 10, Molloy found that errors in the government's environmental reviews were "sufficiently serious" to reverse approval of an expansion to the Bull Mountains Mine. The decision will make the Interior Department and Signal Peak start over with a new application that complies with the National Environmental Policy Act.

"The Enforcement Office's errors cast substantial doubt on the agency's decision to approve the Mine Expansion in the first instance," Molloy wrote. "That doubt is then augmented, not assuaged, by the agency's unilateral decision to prepare an EIS at this late stage of the proceedings. Therefore, the agency's errors are sufficiently serious to warrant vacatur."

More: *Montana Free Press*

National/Federal news from our other channels

EPA Reaffirms Key Power Plant Emissions Regulations

NetZero Insider

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

State Briefs

COLORADO

Lawmakers Form Joint Committee to Study High Energy Bills

State legislative leaders last week announced plans to form a six-member, joint select committee to investigate the causes of rising energy bills.

Senate President Steve Fenberg said the committee should consider whether the current structure creates the right incentives, as well as ways to help businesses and households rapidly move away from natural gas appliances to electric alternatives, which could insulate them from volatile commodity markets.

Under legislative rules, the leaders of the House and Senate will each choose two of the six members. Minority leaders will decide the remaining two seats.

More: *CPR News*

IOWA

DNR Plan Would Reduce 10,000 Tons of MidAmerican Emissions

A revised plan proposed by the Department of Natural Resources would require MidAmerican Energy to improve equipment at certain coal-fired power plants by the end of this year, which would reduce sulfur-dioxide emissions by about 9,700 tons annually.

The plan to limit human-made haze targets two MidAmerican coal-fired power plants: the Louisa Generating Station and the Walter Scott Jr. Energy Center. The improvements are estimated to reduce about 3,900 tons of SO_2 emissions from the Louisa Generating Station and about 5,800 tons from the Walter Scott Jr. Energy Center.

The federal regional haze rule was announced in 1999 under the Clean Air Act to eliminate human-made visibility impairments in 156 national parks and wilderness areas by 2064. States are required to submit 10-year plans for restoring natural visibility conditions, along with progress reports every five years. Iowa doesn't contain any areas that are protected under this rule, however, based on data modeling, emissions from the state could comprise between 3% and 4% of human-made haze plaguing areas in Michigan, Minnesota and Missouri.

More: *The Gazette*

LOUISIANA

Kindle Energy Breaks Ground on Natural Gas Plant

Kindle Energy last week broke ground on a $750 million natural gas plant in Iberville Parish.

The 700-MW Magnolia Power Generating Station will sit on 112 acres along the Mississippi River and will provide electricity to several cooperatives.

The plant is expected to begin commercial operations in May 2025.

More: *The Advocate*

MINNESOTA

House Democrats Introduce Ban on New Gas Lawn Mowers

A bill introduced in the House would ban the sale of new gas-powered lawn mowers and other garden equipment starting in 2025.

The requirement would apply to all lawn and garden equipment powered at or below 19 kW or 25 gross horsepower.

A study by Edmunds in 2011 found that a consumer-grade leaf blower emits more pollutants than a full-sized, high-performance pick-up truck.

More: *Minnesota Reformer*

MISSOURI

Lawmakers Move to Unplug Local Rules on EV Charging Stations

The House of Representatives last week gave first-round approval to a plan that would block cities and counties from requiring that developers install electric vehicle charging stations at new construction projects.

Rep. Jim Murphy, the bill's sponsor, said charging technology could change as technology advances, resulting in the state mandating businesses to install soon-to-be outmoded stations. Under his plan, any city or county that requires the installation of charging stations must pay all the costs.

The bill will need a final vote in the House.

More: *St. Louis Post-Dispatch*

OHIO

Siting Board Approves Solar Projects in Hancock County

The Power Sitting Board last week approved multiple solar projects in Hancock County.

The board approved South Branch Solar's 129-MW solar-powered electric generating facility in Washington Township that will consist of arrays of solar panels and associated facilities. It also approved Border Basin I's similar 120-MW facility in Cass Township.

More: *WTVG*

TEXAS

Austin Terminated City Manager's Contract

The Austin City Council last week voted to terminate the contract with City Manager Spencer Cronk, effective Feb. 16.

While no definitive reason was given, Cronk had been under fire for the city's response to the ice storm that hit Austin and left more than 100,000 homes and businesses without power earlier this month.

Cronk, who will receive a one-year severance of $463,000, had been the city manager since 2018. Jesús Garza was named interim city manager.

More: *Austin American-Statesman*

VIRGINIA

Senate Democrats Defeat Bill Seeking to Repeal Clean Car Standards

The Senate Agriculture, Conservation and Natural Resources Committee last week voted 8-7 along party lines to defeat the bill that would have rolled back a law tying the state to California emissions standards and banned the sale of new gas-powered vehicles in 2035.

Under the federal Clean Air Act, states have two options regulating vehicle emissions: the federal standard or standards enacted by the California Air Resources Board. Last year, CARB adopted stricter regulations that will ban the sale of new gas-powered light-duty vehicles in 2035. The rule is phased in, with 35% percent of new cars sold required to be zero emission in 2026.

More: *Virginia Mercury*

Senate Panel Votes to Exclude Nuclear Research from Power Innovation Fund

The Senate Finance Committee last week voted 10-6 to send an amended bill to the House of Representative that removes nuclear research from the list of technologies eligible for money from the Virginia Power Innovation Fund.

Del. Israel O'Quinn (R-Washington County) last week filed a bill to create a public fund that would be used solely for research and development in innovative energy technologies, also including hydrogen, geothermal, pumped storage hydropower, battery storage and manufacturing, and carbon capture and utilization.

Exploration of new nuclear technologies was a key driver of O'Quinn's proposal in light of Gov. Glenn Youngkin's announcement last year that his administration plans to deploy at least one small modular nuclear reactor somewhere in the state within 10 years.

More: *Cardinals News*

WEST VIRGINIA

Senate Committee Passes Bill to Require Approval of Plant Demolishing

The Senate Energy, Industry and Mining Committee last week unanimously approved a bill that would require utilities to obtain Public Energy Authority approval to decommission or demolish an existing power plant.

The utility would have to file a petition with the PEA and include a third-party analysis of the social, environmental and economic impacts of the action. The petition would also include potential alternatives.

The bill now goes to the full Senate.

More: *The Dominion Post*