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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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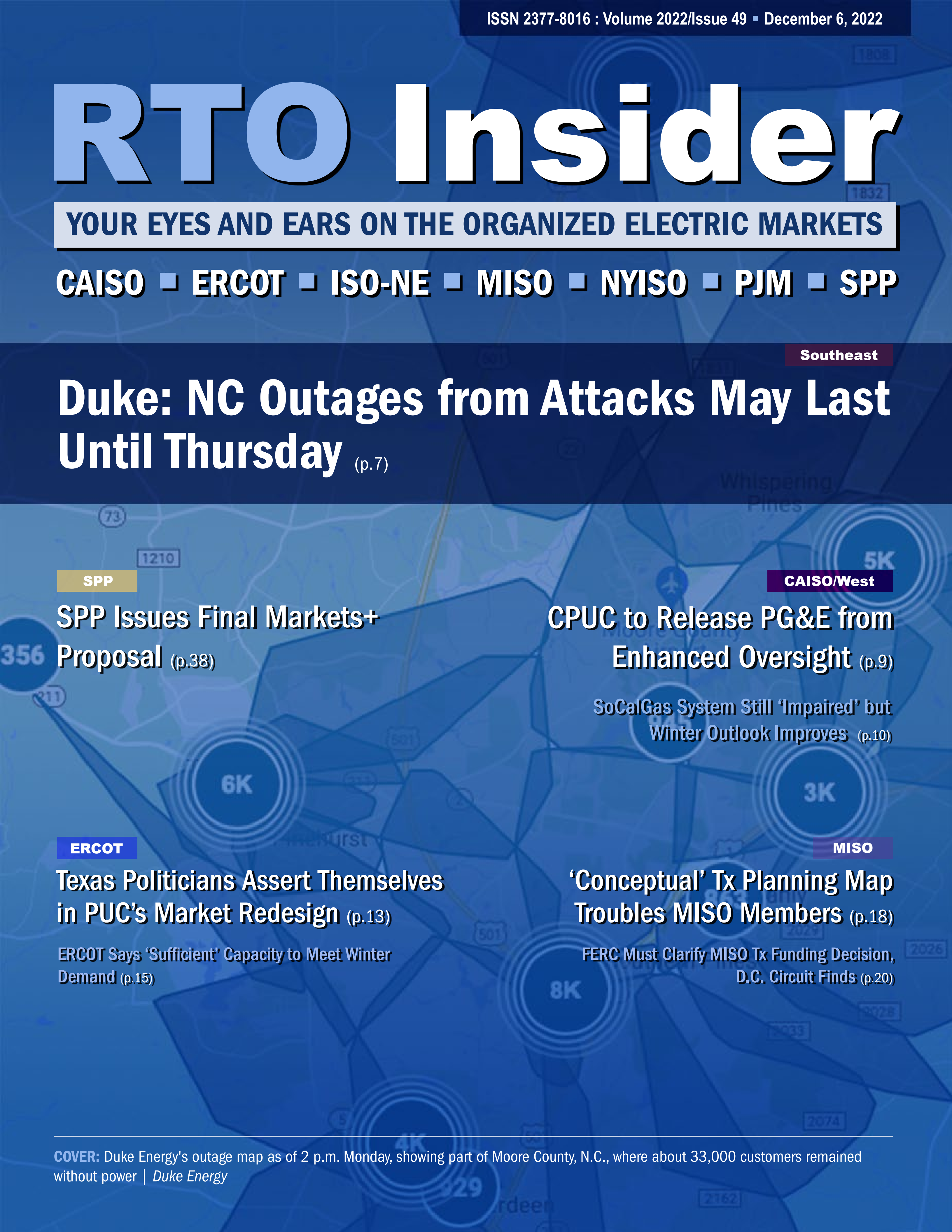

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COVER: Duke Energy's outage map as of 2 p.m. Monday, showing part of Moore County, N.C., where about 33,000 customers remained without power | *Duke Energy*

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Red State AGs Challenge Vanguard Climate Activism

By Rich Heidorn Jr.

In addition to the challenge by attorneys general in conservative states, Vanguard's climate policies have also attracted protests by climate activists such as the Earth Quaker Action Team, which says the fund manager is "the world's largest investor in coal and No. 2 investor in major climate-harming projects across the globe." | *Earth Quaker Action Team*

Attorneys general from 13 conservative states asked FERC last week to reject Vanguard's request for a waiver allowing it to acquire large stakes in utilities, saying the investment giant's climate activism violates its promise not to influence the companies' management (*EC19-57-001*).

Attorneys general from Utah, Indiana, Alabama, Arkansas, Kentucky, Louisiana, Mississippi, Montana, Nebraska, Ohio, South Carolina, South Dakota and Texas cited Section 203 of the Federal Power Act, which prohibits holding companies like Vanguard from acquiring more than $10 million in securities of a utility without commission authorization.

In 2019, the commission granted Vanguard a blanket authorization to acquire up to 20% ownership in aggregate by Vanguard and its affiliates and subsidiaries or up to 10% ownership by any individual Vanguard fund. The commission said it was relying on Vanguard's assurances that it would not invest "for the purpose of managing" utility companies or seek to "exercise any control over the day-to-day management" of them.

"Now, Vanguard's own public commitments and other statements have at the very least created the appearance that Vanguard has breached its promises to the commission by engaging in environmental activism and using its financial influence to manipulate the activities of the utility companies in its portfolio," the AGs said. They asked the commission to hold a hearing to determine whether Vanguard has violated the 2019 authorization and whether granting it an extension is in the public interest.

In February, Vanguard *asked* FERC to extend the initial three-year authorization for another three years.

Vanguard did not respond to a request for comment Wednesday.

The AGs cited Vanguard's 2021 decision to join the Net Zero Asset Managers Alliance, nearly 300 asset managers who pledge to work together to "accelerate the transition towards global net zero emissions" and to prioritize "the achievement of real economy emissions reductions within the sectors and companies in which [it] invest[s]."

The states also pointed to Vanguard's membership in the Ceres Investor Network, which works with "investors around the world to accelerate action on climate change." Vanguard has told its portfolio companies that it will support shareholder proposals requiring the pursuit of climate risk mitigation targets, the states say.

They noted that Berkshire Hathaway's PacifiCorp, which serves Utah, currently gets 20% of its energy from coal or natural gas. "Consumers in Utah would be harmed if their costs went up because of closure of these facilities or substitution of more expensive energy sources," they said.

"We are concerned that Vanguard's actions with respect to influencing environmental corporate policy — especially in combination with the stated motives of [money managers] BlackRock and State Street Global Advisors — will inflate the rates consumers and our states pay for electrical service." (See *BlackRock to Divest from Coal Companies*.)

Extension Sought

Vanguard's request to extend the 2019 waiver also asked FERC to exclude from the 10% and 20% limits securities of utilities in portfolios managed by unaffiliated external advisers.

On Aug. 8, the Office of Energy Market Regulation extended the 2019 authorization for nine months, prompting a critical joint statement from Republican Commissioners James Danly and Mark Christie, who noted that Vanguard's assets under management have increased from about $5 trillion to $8.5 trillion since the 2019 order.

"Vanguard's application raises a number of issues that demand commission scrutiny because Vanguard could potentially exercise profound control over the utilities it owns," they said. "The commission cannot merely rubber stamp requests for blanket authorizations if it is to carry out its statutory duty to ensure that the accumulation of such substantial equity in utilities is not contrary to the public interest. Should a company like Vanguard seek to influence the management and operation of utilities' generation portfolio, for example, this could have a significant impact on the rates consumers pay for electrical service."

'Woke' or Not?

In addition to the challenge by the AGs in conservative states, Vanguard's climate policies have also attracted protests by climate activists such as the *Earth Quaker Action Team*, which says the fund manager is "the world's largest investor in coal and No. 2 investor in major climate-harming projects across the globe." ■

FERC/Federal News

Solar Industry Slams Commerce Decision Extending Solar Tariffs

Even with IRA Tax Incentives, Industry Will Need 5 Years or More to Build US Supply Chain

By K Kaufmann

Criticism from the U.S. solar and clean technology sector was almost instantaneous on Friday after the Commerce Department issued a *preliminary decision* that could extend tariffs on solar cells and panels imported from 22 companies in Cambodia, Malaysia, Thailand and Vietnam.

According to a Commerce Department investigation — begun in February after a complaint from Auxin Solar, a U.S. manufacturer — those companies are using key components from China in a way that allows them to circumvent existing tariffs, called *anti-dumping and countervailing duties* (AD/CVD).

Four companies — New East Solar in Cambodia; Hanwha Q Cells and Jinko Solar Technology in Malaysia; and Boviet Solar Technology in Vietnam — were found not to be circumventing and are exempted from the duties. Other companies can avoid the tariffs through a certification process.

Abigail Ross Hopper, CEO of the Solar Energy Industries Association (SEIA), called the preliminary decision "a mistake we will have to deal with for the next several years."

While "Commerce didn't target all imports from the subject countries," Hopper said, "this decision will strand billions of dollars' worth of American clean energy investments and result in the significant loss of good-paying, American, clean energy jobs."

Following industry outcry about the investigation, President Biden ordered a *two-year moratorium* on AD/CVD on solar cells and panels from the four countries, which will end in June 2024. But, Hopper said, even that breathing space "is simply not enough time to establish manufacturing supply chains that will meet U.S. solar demand."

Gregory Wetstone, CEO of the American Council on Renewable Energy, also called the decision "a major step backward."

The preliminary decision "creates new challenges that threaten to undermine Biden administration efforts to address climate change and accelerate the clean energy transition," Wetstone said. "The Commerce Department appears to be doubling down on constricting solar availability and imposing massive new red tape with certification requirements that could further chill the industry and thwart the administration's clean energy objectives."

Others, like JC Sandberg, interim CEO of the American Clean Power Association, argued that the tariffs would undercut efforts to build out a domestic supply chain for solar, including the tax credits for solar and other clean energy manufacturing in the Inflation Reduction Act.

"American solar companies are making critical

| Shutterstock

FERC/Federal News

2024 procurement decisions now, and today's decision casts greater uncertainty about the future of the solar industry in the U.S. that could lead to higher electricity bills," Sandberg said.

Not all reactions were negative. Michael Stumo, CEO of the Coalition for a Prosperous America, a nonprofit focused on trade issues, welcomed the decision as "an important win for the rule of law" and criticized Biden's tariff moratorium.

"At a time when American manufacturers are investing *billions* of dollars to boost domestic production as a result of the Inflation Reduction Act, it is unconscionable that the White House wants to continue to give Chinese manufacturers a pass for illegally violating U.S. trade law to the detriment of American companies and American workers," Stumo said.

The Commerce Department will be verifying the information in the preliminary decision and accepting comments from industry stakeholders, according to a Friday *press release*. A final decision is now scheduled for May 1, 2023.

'Minor or Insignificant'

The Commerce Department first slapped tariffs on Chinese solar panels in 2012, siding with U.S. solar companies that argued that Chinese companies, heavily subsidized by the Chinese government, were undercutting domestic manufacturers and dumping cheaper panels in the U.S. market. Tariffs — from 31 to 250% at the time — would level the playing field and spur the buildout of a domestic supply chain, they argued.

Ten years on, solar manufacturing has migrated to Cambodia, Malaysia, Thailand and Vietnam; the solar industry and federal government continue to fight over solar trade policy, and the U.S. still does not have a comprehensive domestic supply chain. In 2018, former President Donald Trump expanded the Chinese tariffs to the four Southeast Asian countries, where solar panels are manufactured using Chinese components. Biden decided in February to continue the tariffs, later adding the two-year moratorium.

Arguments for and against the current decision hinge on differing perceptions of the manufacturing processes occurring at solar companies in the four countries, the extent of Chinese involvement and the U.S. solar industry's ability to build out a comprehensive domestic supply chain.

According to industry analysts ClearView Energy Partners, the preliminary decision reflects the Commerce Department's "protectionist leanings." The decision generally concludes "that the value of the merchandise produced in China before it was sent to the Southeast Asian nations represented a 'significant portion of the total value' of the final product exported to the U.S.," ClearView said in a research note released Friday.

Further, Commerce said, the processes for assembling and completing cells and panels in these countries were "minor and insignificant," according to ClearView.

As outlined in the preliminary decision, Commerce based its findings on information gathered in response to questionnaires sent to companies in the four countries. Companies that did not provide the information requested on time and "failed to cooperate to the best of their abilities" were subject to an "adverse inference" that they were circumventing the AD/CVD tariffs.

But SEIA's Hopper said Commerce had "elected to exceed its legal authority. As a basic fact, solar cell and module manufacturing greatly exceed the anticircumvention statute's 'minor or insignificant processing' limitation."

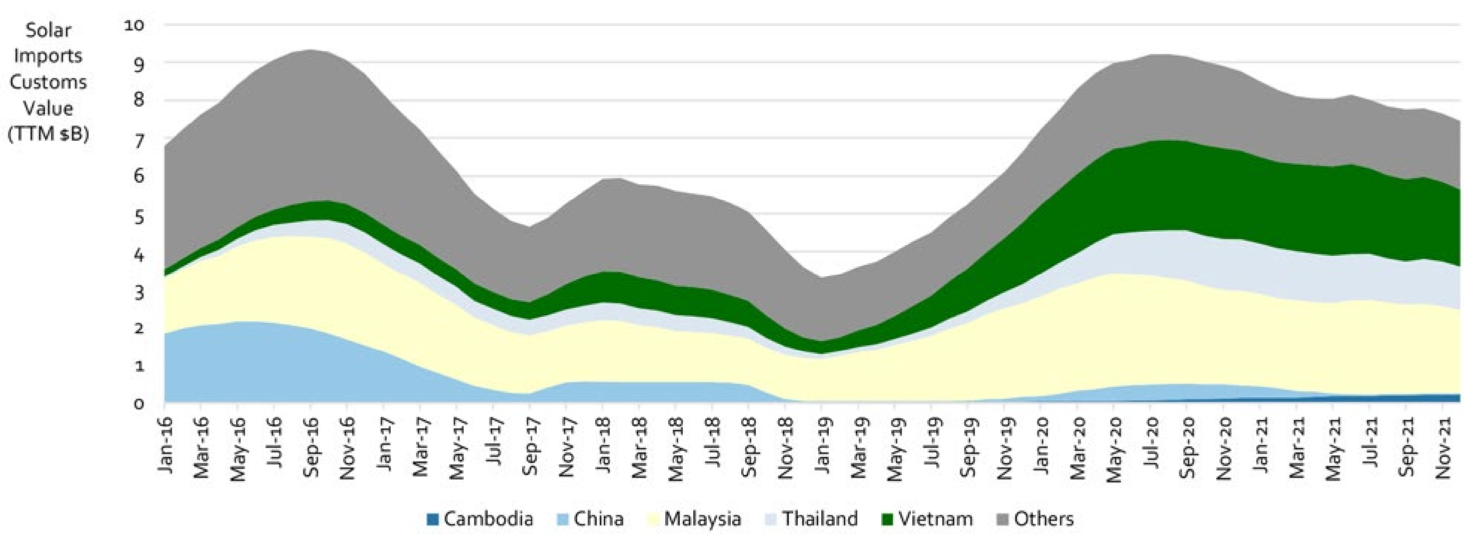
George Hershman, CEO of SOLV Energy, a utility-scale solar installer, also argued that the processes being penalized in the decision are the same as those the IRA seeks to incentivize. The preliminary decision is "inherently hypocritical" and "doesn't pass the common sense test," Hershman said.

"This ruling will further constrict a challenged supply chain and undercut our ability to fulfill the promise of the Inflation Reduction Act," he said.

ClearView agreed the decision "could add to solar product trade risk."

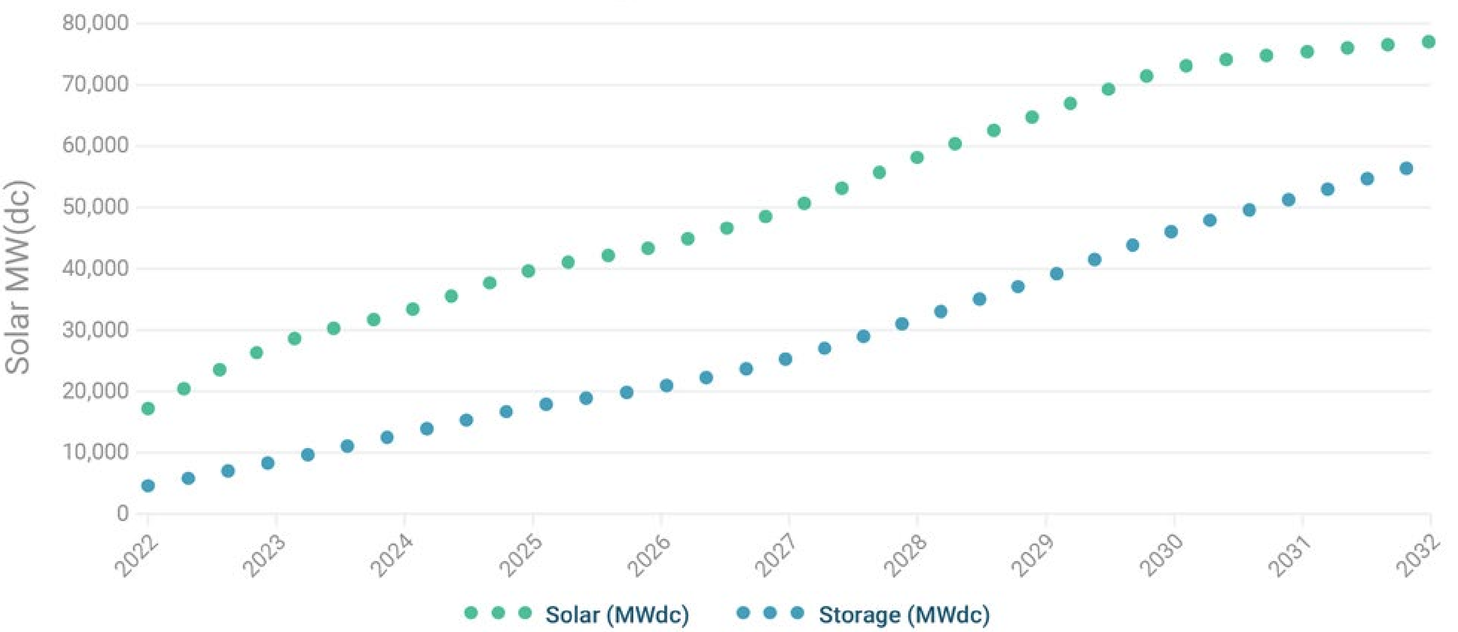
IRA tax incentives could "encourage domestic manufacturing, but our review of solar products demand and recently announced U.S. investments suggests the U.S. market is likely to remain partially reliant on imported solar modules and heavy reliant on overseas solar supply chains after the AD/CVD might take effect," ClearView said.

New solar installations in the U.S. hit 18.9 GW in 2021, ClearView said, and the U.S. Energy Information Administration expects that number to more than double, to 39.7 GW in 2023.



U.S. solar product imports by exporting nation. The Commerce Department preliminary decision could result in tariffs on these imports. | *ClearView Energy Partners*

FERC/Federal News



SEIA projects the U.S. can build out key domestic supply chains for solar by 2027. | *SEIA*

Exceptions

In a *report* released in August, SEIA predicted that building out a full domestic supply chain for all solar components, from polysilicon wafers to inverters, could take five years or longer. The group is targeting a U.S. supply chain capable of producing 50 GW of "domestic solar manufacturing capacity" by 2030.

According to the report, "the United States currently has no domestic solar ingot, wafer or cell manufacturing capacity and only modest capacity to produce solar modules, inverters and trackers. … Practical timelines for siting, permitting, constructing and commissioning new factories [will] influence how quickly domestic manufacturing can scale."

Ingots are blocks of polysilicon, which are then sliced into the superthin "wafers" that go into the solar cells used to produce panels. According to industry analyst *Bernreuter*, seven of the top 10 polysilicon producers in the world are Chinese companies.

But another industry analyst, who requested anonymity because he is not authorized to speak publicly, said that the details of the decision provide a range of loopholes for companies to avoid the tariffs once Biden's moratorium expires.

First, the exclusion of Hanwha and Jinko, both major U.S. suppliers, provides some certainty for the industry, he said.

The decision also excludes solar cells and panels made with wafers not specifically produced in China, even if the silicon ingots they are sliced off of are. "That means that all the … production [of wafers] that is online and coming online in Southeast Asia can be made into cells that are not subject to duties," he said.

Another big loophole is the exclusion for cells and panels where four of six key components — silver paste, aluminum frames, glass, backsheets, ethylene vinyl acetate (EVA) sheets and junction boxes — are not made in China. Silver paste is a conductive material used to improve electricity production in solar panels, and EVA sheets are used to "encapsulate" and protect solar cells in panels.

"If you have four of the six … made outside of China, no duties. That's not going to be hard to comply with," the analyst said. "You can make aluminum frames anywhere; you can make glass a lot of places; backsheets, EVA; there's no reason you have to make this stuff in China. … And then suddenly — boom — all of those modules aren't subject to duties.

"This was a much better decision for the industry than people may realize," he said. "The fine print here is really positive for us to continue to have module supply for the next few years."

But, the analyst cautioned, building out a U.S. supply chain, especially for ingots and wafers, will face challenges. Setting up the new factories will be capital intensive, "and you need somebody who's got the know-how to do them," he said. "That ingot and wafer knowledge is now concentrated in Asia, so you have the same problem." ■

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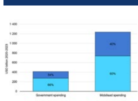
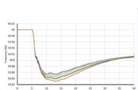


IEA: Global Energy Crisis Puts Efficiency at 'Center of Policy Agendas'

NetZero Insider



NERC Report Recommends No Change to DER Study Thresholds

ERO Insider

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

Southeast

Duke: NC Outages from Attacks May Last Until Thursday

Sheriff Says Culprits 'Knew Exactly What They Were Doing'

By Holden Mann

More than 33,000 customers remained without power Monday afternoon in Moore County, N.C., following apparent attacks on two of Duke Energy's substations over the weekend, and the company said some customers may not see their electricity restored until Thursday.

The outages began near the town of Carthage about 7 p.m. Saturday. They "shortly thereafter … spread to the greater majority of central and southern Moore County," Sheriff Ronnie Fields said in a *press conference* Sunday afternoon. At the height of the outages, more than 45,000 customers had lost power, Duke said in a *press release* on Sunday; the utility's *outage map* has been updated since then to reflect the restoration of some customers as crews work in 24-hour shifts, Duke confirmed to *RTO Insider*.

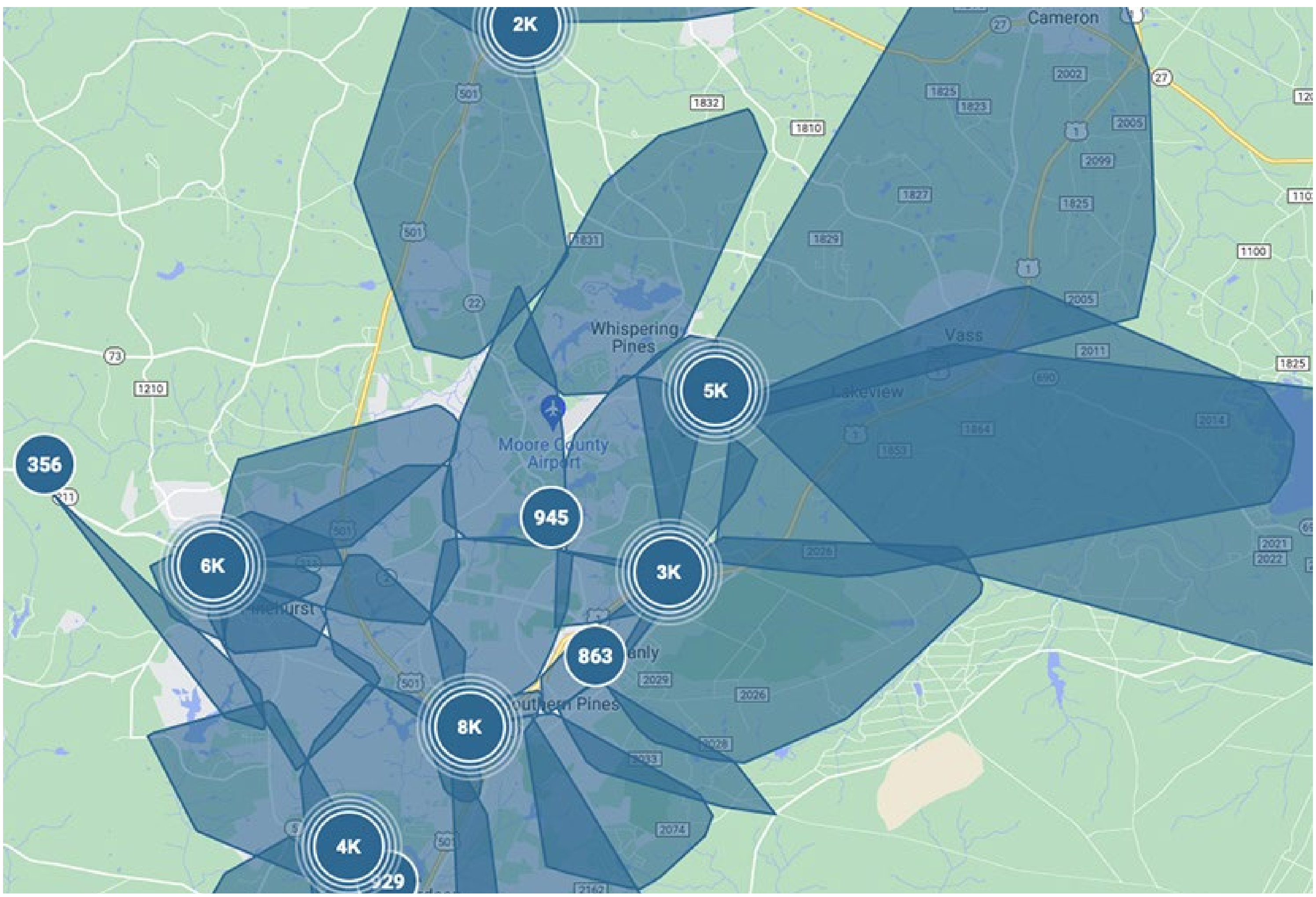
'Pretty Sophisticated Repair'

Crews and sheriff's deputies investigating the outages discovered "extensive damage" to two substations. Fields said the deputies found evidence indicating that firearms had been used to disable the facilities with "multiple shots" fired by attackers who "knew exactly what they were doing." Duke said parts of the substations had been damaged "beyond repair," requiring technicians to completely replace the affected equipment.

Duke spokesperson Jeff Brooks said at Sunday's press conference that "we are looking at a pretty sophisticated repair with some fairly large equipment," and that Duke is "pursuing multiple paths of restoration [to] restore as many customers as possible, as quickly as possible."

The county implemented a 9 p.m.-5 a.m. curfew Sunday night "to best protect our citizens and … businesses of our county," Fields said. Additionally, most county operations were shut down on Monday except emergency services, along with limited transportation for medical needs. County Manager Wayne Vest said that the county would probably be working "a skeletal operation" through Monday and hope to "get back up to full speed" by Wednesday.

"We faced something [Saturday] night here in Moore County that we've never faced before, but I promise you we're going to get through this, and we'll get through it together," Fields said at the press conference. "We're very united here in Moore County, and we're not going to let this hold us back, and I can promise you, to the perpetrators out there, we will find you."



Duke Energy's outage map as of 2 p.m. Monday, showing part of Moore County, N.C., where about 33,000 customers remained without power | *Duke Energy*

Southeast

No Known Motivation

Law enforcement has not publicly identified any culprit or motivation for the attacks so far. Fields said that "every available officer" in his office is doing "what we can to try to determine what happened," with municipal and state officials contributing to the effort, along with the FBI.

The Electricity Subsector Coordinating Council (ESCC) said in a statement Monday that it was "working closely with … law enforcement officials" in their investigation into the attacks. Participants in an ESCC-hosted conference call Monday night included FERC Chairman Richard Glick; Brandon Wales, executive director of the Department of Homeland Security's Cybersecurity and Infrastructure Security Agency; and Deputy Energy Secretary David Turk.

The ERO Enterprise has also mobilized in response to the incident. SERC Reliability CEO Jason Blake said in a statement that the regional entity is "in close coordination" with Duke, NERC, federal agencies and "appropriate industry members across our 16-state footprint [so that] information is shared as it becomes known and that utilities across our footprint are in a heightened security posture."

Asked about *online rumors* that the attacks were meant to shut down a local drag show that was planned to occur Saturday night, Fields said that while "anything's possible," the office had "not been able to tie anything back" to the show. Calling the perpetrators "cowards," he acknowledged that no person or group had stepped forward to take responsibility for the attacks, adding that while the targeting of the power grid "wasn't random," he could not say at this point whether the incident should be considered an act of domestic terrorism.

The suspected connection to the drag show was apparently strengthened by a series of

Moore County Sheriff Ronnie Fields at a press conference Sunday afternoon | *WRAL-TV*

provocative Facebook posts by Emily Grace Rainey, a self-proclaimed conservative activist living in Moore County who served in the U.S. Army before resigning amid an investigation of her participation in the Jan. 6, 2021, attack on the U.S. Capitol.

Before the outage began, Rainey had posted the contact information of the drag show's sponsors, adding, "You know what to do." After the outage started she wrote, "The power is out in Moore County, and I know why," later posting a picture of the theater where the show was supposed to be held with a caption saying, "God will not be mocked."

However, Fields said on Sunday that while deputies had interviewed and "had a word" with Rainey, the lead "turned out to be nothing." He urged citizens not to post false information online, reminding listeners that it "takes time for us to run that down."

History of Physical Security Threats

The idea of domestic terrorists attacking the power grid has gained credibility in recent years, especially following the announcement in February that three men had pleaded guilty to planning to damage substations with high-powered rifles. (See *FBI: Conspirators Planned Grid Attack to Start Race War*.) According to their confessions, the men hoped to spark "confusion and unrest" that would lead to a civil war, inspired by "racially or ethnically motivated violent extremist views."

The tactics of Saturday's incident also resemble those of the 2013 attack on Pacific Gas and Electric's Metcalf substation near San Jose, Calif. In that event, whose perpetrators have never been identified, snipers fired an estimated 150 rounds at transformer radiators in the facility, hitting 10 of the 11 targets and resulting in the loss of about 52,000 gallons of cooling oil. (See *Substation Saboteurs 'No Amateurs'*.) The attackers are also believed to have cut underground fiber optic cables near the substation, temporarily disabling phone and 911 service for the area.

Physical security for bulk electric system facilities is addressed in NERC's Critical Infrastructure Protection (CIP) reliability standards, most notably *CIP-014-3* (Physical security), the first version of which was introduced two years after the Metcalf attacks. Asked about security preparations at Duke's substations on Sunday, Brooks said that "we take security extremely seriously" and that the utility was confident its security requirements were in place at the affected facilities.

"We understand that we're critical infrastructure, and so we do incorporate multiple layers of security at all of our facilities and across our system to help protect the grid and … restore power when we have disruptions," Brooks said. "We can't provide specific information on security measures at a critical facility, but I can say that certainly we're one of the most highly regulated industries in the country. There's a lot of protocols around security that we follow, and we believe we followed those in this case." ■

CAISO/West News

CPUC Releases PG&E from Enhanced Oversight

By Hudson Sangree

The California Public Utilities Commission on Thursday allowed Pacific Gas & Electric to exit an enhanced oversight and enforcement process the CPUC created two years ago to prevent the utility from starting catastrophic wildfires, but commissioners warned they would use the process again if needed.

Before the unanimous vote on a *resolution* freeing the utility from enhanced oversight, commissioners emphasized that PG&E had entered the first step of the six-step process because of particular problems with its vegetation management practices, and that it was being released because it had met specific goals imposed by the CPUC.

"This is an illustration of how the enhanced oversight and enforcement process can be effectively used," Commissioner Clifford Rechtschaffen said. "It worked here. It's of course not a panacea. No one is suggesting it is, but it did work. It did address an important problem. So, we should not be bashful about using it again."

"PG&E's operational practices remain a serious concern for us, despite everything that's been done, so we should continue to utilize this tool," Rechtschaffen added.

Commissioner Genevieve Shiroma said she would vote for the resolution, but "I do want to be very clear about the limited scope of this resolution and my continued concerns with PG&E's operations."

Other speakers noted that a number of CPUC actions targeting PG&E remain in place. They include an independent safety monitor that reports every six months on the utility operations; specific metrics to evaluate PG&E's safety performance and to implement the enhanced oversight and enforcement (EOE) process; and continuing investigations of PG&E intended to rein in unsafe practices.

The CPUC required PG&E to accept the EOE process as a condition of it approving PG&E's bankruptcy organization plan in June 2020.

In September of that year, a leaning gray pine fell onto a PG&E line and started the Zogg Fire in rural Northern California, killing four people and leading to additional scrutiny of PG&E's tree clearing efforts by the CPUC and the federal judge who oversaw PG&E's criminal probation from the 2010 San Bruno gas explosion.

A photo filed in federal court shows a tree suspected of starting the nearly 1-million-acre Dixie Fire. | *PG&E*

The CPUC used the process for the first and only time against PG&E in April 2021, passing a resolution that said the utility was not "sufficiently prioritizing its enhanced vegetation management based on risk."

PG&E had ranked its power lines based on wildfire risk but failed to perform the majority of its enhanced vegetation management "or even a significant portion of work" on its highest risk lines, the CPUC said at the time. The commission ordered PG&E to submit a corrective action plan and to report every 90 days on its progress clearing high-risk lines of trees and overhanging branches.

Trees and branches falling onto PG&E power lines caused devastating fires over the past five years, including last year's nearly 1 million-acre Dixie Fire, many of the Wine Country fires of 2017 and the Zogg Fire.

The Utility Reform Network and the CPUC's Public Advocate's (Cal Advocates) office argued in a *joint filing* that the Dixie Fire and other activities warranted placing PG&E into a higher step of the EOE process, with escalating oversight and penalties.

"Of particular note was PG&E's failure to identify and remove the damaged and decayed tree" that started the Dixie Fire," TURN and Cal Advocates said.

"When the tree fell and contacted PG&E lines, the utility demonstrated no sense of urgency despite the history of extreme fire danger and poor access in the surrounding region," they said, citing the findings of the California Department of Forestry and Fire Protection. "PG&E's delayed response allowed the tree to remain in contact with energized lines for approximately 10 hours and was a direct and negligent factor in the ignition of the fire."

The CPUC decided those concerns and others were outside the bounds of the current proceeding. They found that PG&E had met the requirements of its corrective action plan and shown that it had prioritized work on high-risk lines.

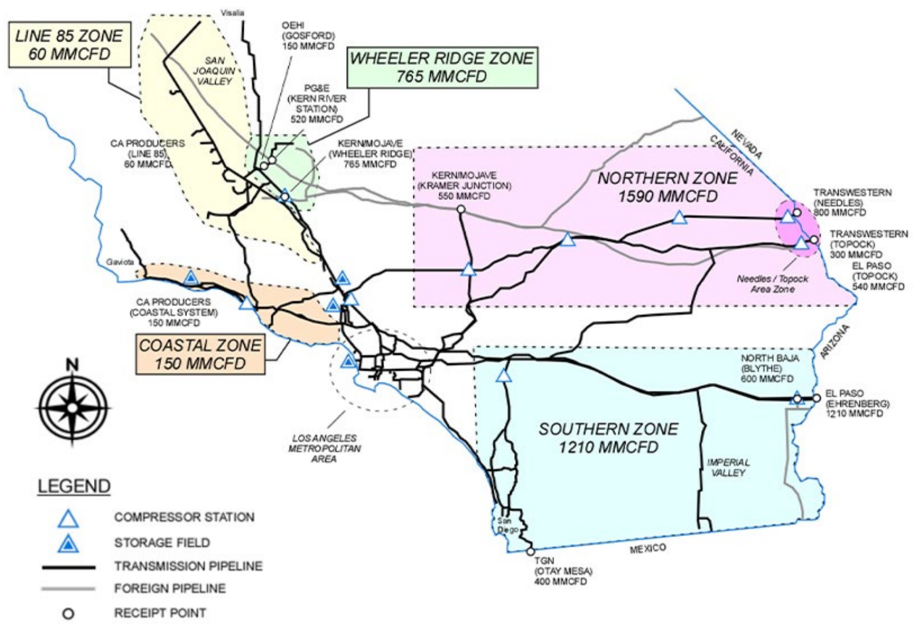
"PG&E's goal was to perform more than 80% of its [enhanced vegetation management] work in the top 20% highest risk circuit protection zones in 2021," Thursday's resolution said. The utility exceeded that goal by completing 98% of its tree clearing in 2021 on its highest risk lines and met other CPUC criteria, allowing to leave the EOE process, it said. ■

CAISO/West News

SoCalGas System Still 'Impaired' but Winter Outlook Improves

By Hudson Sangree

Southern California Gas' system remains "impaired," but the risk of service reductions is lower than in previous years because a warm winter forecast could reduce demand for gas-fired electric generation, the California Energy Commission heard Wednesday.



The Southern California Gas transmission system serves a vast area of Southern and Central California. | *SoCalGas*

During a joint workshop with the California Public Utilities Commission, Energy Commission staff said two key pipelines are operating at reduced capacity, including one pipeline that ruptured in 2017. An El Paso Natural Gas mainline that ruptured last year south of Phoenix is shut down, limiting supply from the Permian Basin. And storage at SoCalGas' Aliso Canyon natural gas storage facility continues to be restricted after one of the worst methane leaks in U.S. history in 2015-16.

"Recognizing these restrictions, staff assesses that the risk of service interruptions is lower this winter than in recent winters," CEC staff wrote in a *briefing paper*. "This lowered risk is largely due to forecast demand being lower than in prior years. Specifically, staff projects zero curtailment on a winter day cold enough to occur once in 10 years."

In colder conditions, SoCalGas might have to curtail 280 million cubic feet per day, a tenth of its total pipeline flow of 2.8 million cubic feet per day, the CEC said. The curtailment would affect "noncore load," mainly electric generators plus some industrial customers and other users.

"Any adverse event, such as a pipeline going out of service, could lead to a higher curtailment," the CEC report said. "The key risk to reliability is multiday cold weather events with additional infrastructure outages."

SoCalGas serves nearly 22 million customers, about the same as the population of Florida, in its 24,000 square mile territory.

The CEC's review is part of its informational proceeding on decarbonization, which it launched with a workshop in June.

"The Energy Commission is making great strides towards enhancing our modeling and analytical capabilities in this winter assessment," Chair David Hochschild said at Wednesday's workshop. "We are using our own gas-demand forecast results for the first time, [and] we've been able to dig deeper into the winter demand scenarios. All this leads to more verifiable results that feed into the gas decarb."

Aliso Canyon

Aliso Canyon, regarded as both a threat to public safety and essential for reliability, has been a sticking point in that effort.

Residents and public officials have repeatedly called for its shutdown after it spewed more than 100,000 tons of gas into the atmosphere. The leak was contained after four months and multiple failed attempts.

SoCalGas and parent Sempra Energy agreed to pay $1.8 billion last year to settle the claims of 35,000 residents who claimed they suffered physically and emotionally from the leak.

In November 2021, California's two Democratic senators, Dianne Feinstein and Alex Padilla, issued a joint statement saying it is "critical that the California Public Utilities Commission outline concrete steps to close this facility while ensuring the reliability of our power grid."

The storage facility serves more than 11 million customers and provides fuel to 17 gas-fired plants, according to SoCalGas.

"It is a critical part of the region's energy infrastructure," the utility says on its website. "More than 90% of Southern Californians depend on gas for heat and hot water, and approximately 60% of all the electricity generated in California is made by natural gas-fired power plants."

Last November, the CPUC increased Aliso Canyon's storage limits from 34 billion cubic feet to 41 billion cubic feet because of reliability concerns — still well below its pre-leak capacity of 86 Bcf. Climate change-induced extreme weather "unfortunately has created greater short-term dependency on natural gas generation," former Commissioner Martha Guzman Aceves said at the time. ■

West news from our other channels

CARB Prepares Launch of $13M E-bike Incentive Program

NetZero Insider

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CAISO/West News

Western Energy Leaders Explore Grid Integration

By Hudson Sangree

Energy officials from California and across the West weighed the potential benefits of Western electricity system integration for cost savings, transmission and resource adequacy in an all-day workshop Friday hosted by the California Energy Commission.

The *workshop* was meant to brief a broader audience, including state lawmakers, on regional market developments. In the past year, CAISO and some California lawmakers have advanced the idea that California should play a larger role in regional markets as it faces competition from challengers such as SPP.

Friday's session was part of the commission's Integrated Energy Policy Report (IEPR), a biennial assessment of energy issues and policy recommendations in which the CEC tries "to elevate important topics to make sure … the state Legislature is aware of what is happening in the energy space," Commission Vice Chair Siva Gunda said.

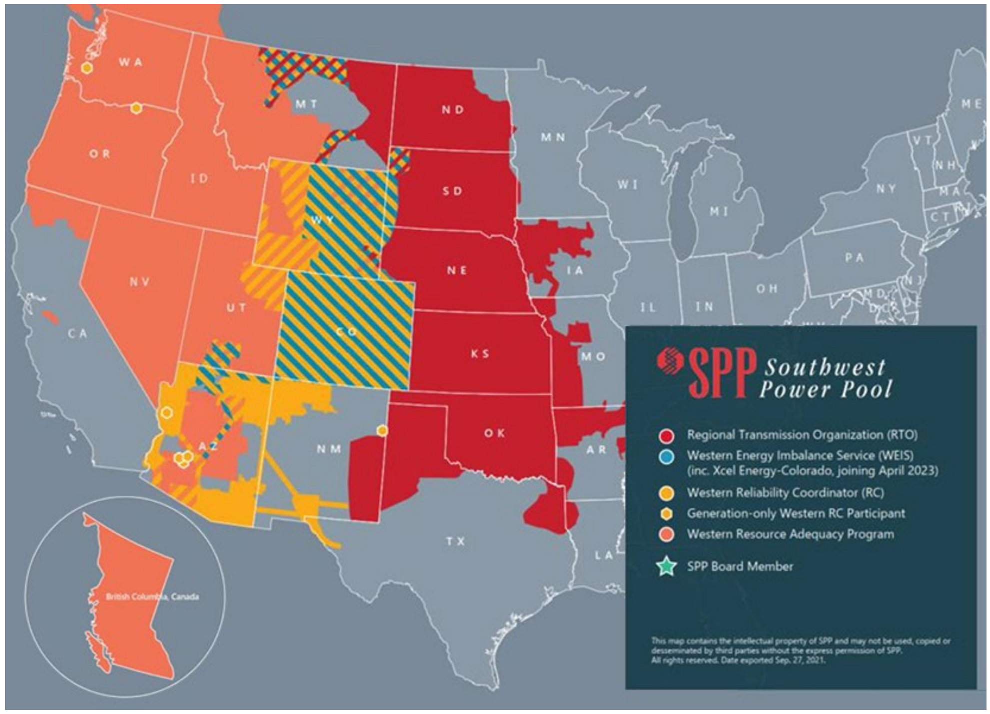
"So, with that spirit, we have included the Western integration topic as an important element of this year's IEPR," Gunda said. "A lot has been happening over the last couple of years, and we thought it's extremely important to provide a transparent, high-level update on what's happening in the West as it pertains to Western integration and the markets."

CAISO, for instance, began a stakeholder process in mid-October to explore the benefits of greater regional cooperation and a Western RTO, as California lawmakers had requested in Assembly Concurrent Resolution 188 in August. The resolution's goals were limited, requiring only that CAISO report to the Legislature on recent studies of RTO benefits, but some saw *ACR 188* as a cautious opening gambit in another regionalization effort.

Several prior attempts at turning CAISO into an RTO fizzled in 2016-2018, as most lawmakers balked at broadening its governance to include other states. CAISO is a public benefit corporation created via state statute in 1998; the California governor appoints the five members of its Board of Governors.

However, circumstances have changed substantially since the last legislative attempt to broaden CAISO's governance in 2018.

SPP is making inroads in the West with its Markets+ day-ahead offering and a plan to expand its Eastern RTO into the Western



SPP's plans call for a Western RTO, a day-ahead Markets+ offering and running WPP's WRAP program, in addition to its RC coordinator service and real-time WEIS. | *SPP*

Interconnection. Utilities in Colorado and Wyoming have indicated they plan to join both. (See *SPP Issues Final Markets+ Proposal*.)

The Western Power Pool (formerly the Northwest Power Pool) will soon launch its Western Resource Adequacy Program, which could cover much of the Western Interconnection. WPP hired SPP to administer the program, and some observers have speculated that the WRAP might be a logical precursor to another Western RTO.

Workshop participants met in a hybrid in-person and online gathering to weigh these and other developments. They included members of the California Public Utilities Commission, CAISO CEO Elliot Mainzer, Air Resources Board Chair Liane Randolph and Gov. Gavin Newsom's senior energy adviser Karen Douglas.

Participants from other states included utility commissioners from Colorado and Oregon and representatives of SPP, the Western Interstate Energy Board, the Western Electricity Coordinating Council, the Western Power Pool and the Northwest & Intermountain Power Producers Coalition.

"The attendance here today is indicative of the importance of this conversation," Gunda said.

Role of Markets

A panel exploring the role of regional markets began the substantive discussions.

This year CAISO fast-tracked its extended day-ahead market (EDAM) proposal for its Western Energy Imbalance Market, a real-time interstate trading forum that has saved participants more than $3 billion in the past eight years. The real-time market, however, involves only a small amount of the transactions that occur in day-ahead trading.

"The success of the WEIM demonstrates that there's a potential for a lot more," said Anna McKenna, CAISO vice president of market policy and performance.

A recent study by consulting firm Energy Strategies found the EDAM could generate $1.2 billion a year in benefits, or 60% of the savings of a West-wide RTO, if it encompassed the entire U.S. portion of the Western Interconnection.

Energy Strategies Principal Keegan Moyer said a full Western RTO would generate even greater benefits. His firm estimated the benefits at $2 billion a year in electricity costs in test-year 2030 in a study prepared for state energy offices in Colorado, Idaho, Montana and Utah. (See *Study Shows RTO Could Save West*

CAISO/West News

$2B Yearly by 2030.)

"The EIM was an excellent first step, and the $3 billion number is impressive," Moyer said. "But every data point that we've seen from our work and others is that there's still a lot of opportunity out there, which is why you see so much effort, I think, put into this by the industry."

CAISO has scheduled a stakeholder meeting for Dec. 7 to discuss its final EDAM design and plans to seek approval from its board and the WEIM Governing Body in February.

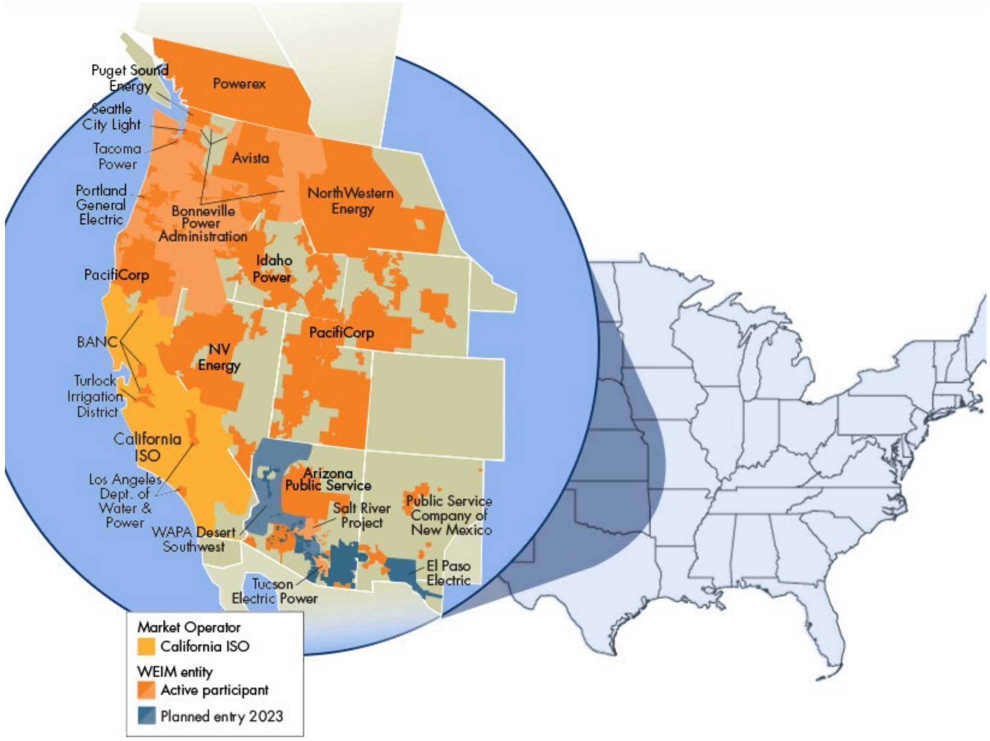
Eric Blank, chair of the Colorado Public Utilities Commission, said a study performed by his commission found increased regional coordination could save the state's electric utilities up to $300 million a year, or about 5% of their costs. State law requires Colorado transmission owners to join an RTO by 2030.

"These benefits were roughly the same whether we went west to CAISO, east to SPP or did something [in between]," the hypothetical study results showed, Blank said.

CAISO's one-state governance is a potential roadblock to expanding it into a Western RTO unless state lawmakers broaden its governance structure. SPP would maintain its inclusive governance structure in the West, Carrie Simpson, the RTO's director of Western services development, said in the workshop.

The expectation is that participants in SPP's existing Western Energy Imbalance Service will eventually join Markets+ and that many Markets+ participants will become members of SPP's planned RTO West, she said.

One diagram in her *presentation* showed a larger RTO West and Markets+ transacting business with CAISO and WEIM. Another used a map showing SPP and WPP dominating the Western landscape, with CAISO relatively isolated. (A comparable CAISO map would show the



CAISO's Western Energy Imbalance Service is expected to encompass nearly 80% of load in the Western Interconnection by next year. | *CAISO*

WEIM covering much of the Western Interconnection.)

Seams between RTOs and ISOs are common in the Eastern Interconnection and would work in the West, including between CAISO and SPP, Simpson said.

"You can have many markets next to each other, optimizing efficiently through seams. We have it in the East. It's very common. MISO, PJM and SPP coordinate regularly together," Simpson said. "And so, to the extent that we have seams [in the West], absolutely we will want to work with all of our neighbors to make sure we're optimizing systems as efficiently as possible to bring the greatest benefits to customers."

Whether California will again seek to form a Western RTO to compete with SPP remains doubtful.

CAISO's ACR 188 report, performed by the National Renewable Energy Laboratories, is being conducted in partnership with Western entities such as NV Energy, PacifiCorp and the Western Area Power Administration. A draft is expected later this month, and CAISO hopes to deliver the report to the Legislature during the first weeks of its 2022 session, which begins Jan. 3. ■

ERCOT News

Texas Politicians Assert Themselves in PUC's Market Redesign

Legislature Asks for Signoff on Changes to ERCOT Grid's Construct

By Tom Kleckner

Texas lawmakers have jumped into the middle of the Public Utility Commission's effort to redesign the ERCOT market, saying they are concerned the PUC's proposals don't do enough to incent investment in new gas-fired generation.

The commission had been quietly working with consultants behind closed doors to develop new market designs that would protect ERCOT against a repeat of 2021's disastrous winter storm. But when the PUC unveiled the results of its work last month, it quickly drew pushback from the market and energy experts over its close resemblance to capacity markets. (See *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

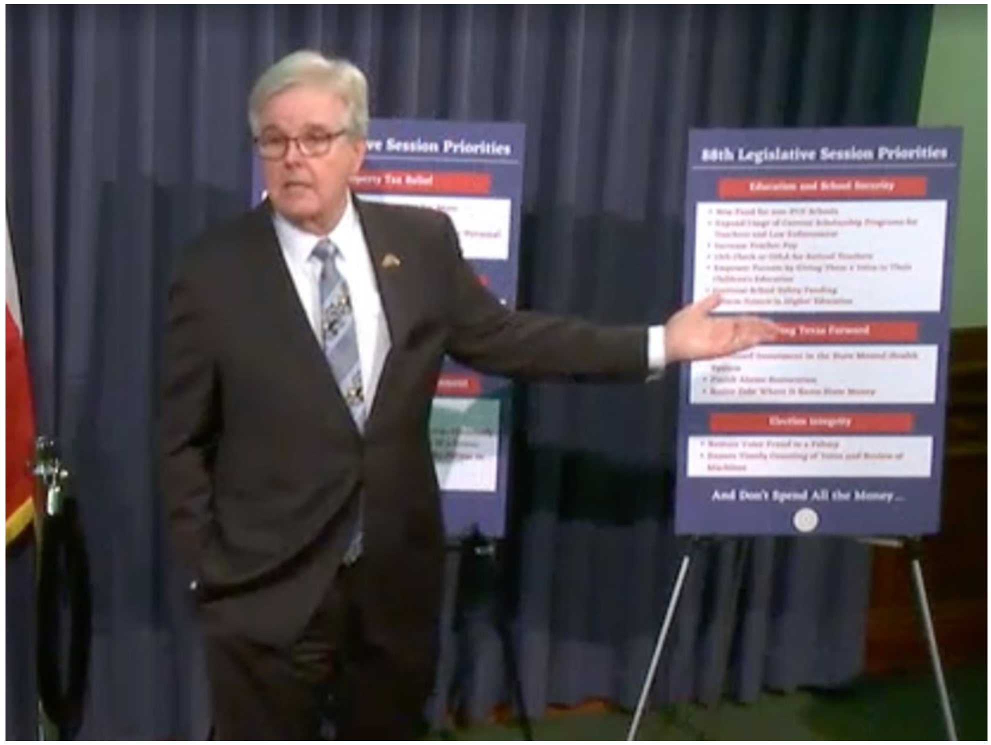
The lead proposal, a performance credit mechanism (PCM) that would require load-serving entities to buy performance-based credits from generation resources that meet reliability standards, has never been tried by a U.S. grid operator. The PUC has asked ERCOT stakeholders and the general public to provide feedback on the PCM and five other market designs by Dec. 15.

However, Texas lawmakers, who see adding more gas-fired, or dispatchable, generation as the solution to the problem (They define dispatchable resources as those not "controlled primarily by forces outside of human control.") have stepped into the fray.

On Wednesday, Lt. Gov. Dan Patrick, who presides over the state Senate and has tremendous influence over its legislation, unveiled his list of priorities for the Texas Legislature's 88th session, which begins Jan. 10. They include improving the grid's reliability; he threatened to keep lawmakers in Austin until they pass legislation that encourages gas-fired power plants to be built.

"Whether it is incentivizing them; whether it's building them; whatever the plan is, I personally cannot see myself leaving this building knowing that another [winter storm] can happen," Patrick, who called renewable energy "a luxury," said during a press conference. "We have to level the playing field so that we attract investment in natural gas plants."

Observers have noted that would put Patrick at odds with Gov. Greg Abbott and Peter Lake, his handpicked commission chair. Both have said the grid is better than ever because of weatherization, coordinated communication and other operational changes put in place at the end of last year.



Texas Lt. Gov. Dan Patrick briefs the media on his 2023 legislative priorities, which include adding gas-fired generation. | *The Texas Senate*

The bipartisan Senate Business and Commerce Committee followed up Patrick by sending a *letter* Thursday to the PUC's commissioners, urging them to stick to the directives in *Senate Bill 3*. The omnibus bill, passed last year following the winter storm that almost brought down ERCOT's grid and left millions of Texans in the dark for days, called for "adequate incentives" for dispatchable generation. It also instructed the PUC to incentivize that dispatchable generation by establishing a reliability standard for the market and using that standard to develop or procure a new ancillary or reliability service for the generators. (See *Abbott Signs Texas Grid Legislation into Law*.)

The committee had already heard from the PUC, ERCOT and stakeholders, having held a hearing on the plan Nov. 17. It said the testimony that day indicated the PCM was an "administratively complex and novel concept" that would "deter new investments in the ERCOT market until it is fully in place." (See *Legislators, Stakeholders Pan Proposed ERCOT Market Design*.)

"By the commission's own admission, [that] could be several years down the road," committee members wrote. "There is significant concern the proposals being considered by the commission … not only failed to meet the directives clearly stated in SB3, but more importantly will not guarantee new dispatchable generation in a timely and cost-effective manner. …

"It is not in the best interest of our constituents to support any proposal that further delays investments in new dispatchable generation, and the commission should carefully consider the unintended consequences of any type of proposal that creates more uncertainty for market participants."

The committee directed the PUC to define ERCOT's reliability goals before moving forward with any "significant" market redesign and to evaluate creating a new market-based ancillary or reliability service to meet reliability standards.

"Any holistic market design change, including the PCM, that goes beyond the scope of SB3 should not be adopted by the commission without further consultation with the legis-

ERCOT News

lature," the committee said in concluding its letter.

The hits could keep coming. On Monday, the House of Representatives' State Affairs Committee held a public hearing to review the proposed market changes.

The PUC seemed unfazed by the legislative comments. It still plans to present a final recommendation to the legislature next year before allowing ERCOT to begin the implementation process.

A spokesman said the commission will develop a reliability service, "as we've said since the beginning of this process."

"The [PUC] published multiple options for consideration and eagerly awaits public comments on all options," Rich Parsons said in an emailed statement. "Once the commission holds a vote on a preferred reliability service, we will present it to the legislature next session."

"The PUC should take this legislative brushback of the chairman's preferred solution very seriously. It's a bad idea to tick off the folks who approve the commission's budget, ap-

Alison Silverstein, Silverstein Consulting | © *RTO Insider LLC*

pointments and headcount," Alison Silverstein, an energy consultant with experience at both the PUC and FERC, told *RTO Insider* on Friday.

She said the PCM proposal is "barely articulated, poorly analyzed, ill-supported and precedent-free, with little evidence that it will produce new gas plants."

"I wouldn't risk the Texas economy and energy affordability for [the PCM]," Silverstein said.

She put in a plug for the backstop reliability service, one of the other five designs. The ancillary service would meet specific reliability needs not met by ERCOT's real-time and ancillary service markets during high uncertainty periods. Silverstein said it would act as an insurance policy that would better manage plant retirements.

Stoic Energy principal Doug Lewin said that building new gas plants will only lead to higher customer bills.

"If you want to lower bills, you need to integrate more renewables and increase energy efficiency," he *tweeted*, noting that a consultant for the PUC has shown that high renewable generation reduces energy costs by 20%.

"No one thing will solve any, much less all, of these problems," Lewin added. "Unfortunately, some policymakers are trying to solve a different problem. They don't like renewables and want more gas plants. That won't solve any of the problems." ■

ERCOT Says 'Sufficient' Capacity to Meet Winter Demand

By Tom Kleckner

ERCOT has "sufficient" installed capacity to meet a forecast peak demand of 67.4 GW this winter, the ISO said last week.

Based on its latest *seasonal assessment of resource adequacy* (SARA), the Texas grid operator expects to have about 87.3 GW of winter-rated capacity available during the upcoming cold months. Two thermal resources, a coal unit and a gas-fired unit comprising 685 MW, will be out of service all season, ERCOT said. The SARA report assumes "typical" thermal outages totaling almost 10 GW this winter.

The projected demand is based on average winter conditions for the 2007-2021 winter peaks that would include the devastating winter storm of February 2021, which still raises Texans' anxiety levels. The SARA report assumes high demand, high thermal outages and low wind output in its various scenarios but not gas supply disruptions, which FERC and NERC said were responsible for most of the generation outages during the 2021 storm. (See *FERC, NERC Release Final Texas Storm Report*.)

ERCOT's demand peaked at 77 GW during the 2021 winter storm before the outages became too much to handle. Texas A&M University's Texas Center for Climate Studies has *said* demand would have reached 82 GW had there been enough generation to meet demand.

But Public Utility Commission Chairman Peter Lake expressed optimism about the grid's preparedness during a joint press conference Nov. 29 with ERCOT CEO Pablo Vegas. "The lights will absolutely stay on," he promised.

Lake trumpeted new weatherization requirements and other reliability-focused operational reforms directed by lawmakers following the storm as the reason for his confidence. "We're better prepared than ever," he said.

"We are in a position where the elements that are within our control related to the reliability and the operation of the grid are as strong as they've ever been going into this winter season," Vegas said. "The majority of the actions that we've taken over the course of this year-and-a-half are designed specifically to address any risk of load-shedding."

The biggest change has been following up on weatherization requirements placed on generators and transmission facilities. After inspecting weatherization practices last winter at plants that experienced problems during the winter storm, ERCOT staff will check on about a third — or 350 — of the system's resources this year. Vegas said the ISO plans to complete the inspections early next year.

"Those inspections and audits are showing that the work is getting done to keep those generators operating during the most extreme weather conditions," he said.

Asked about NERC's recent winter reliability assessment that found ERCOT's reserve margin could fall as much as 21% below demand in the most severe scenario, Vegas transitioned to the PUC's market redesign that is currently underway. (See *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

"That doesn't take into account things like winterization," he said of NERC's assessment. "We're not trying to underplay it at all. It does reflect a very low-probability scenario.

"But the fact it exists calls out an issue that needs to be addressed … being able to continue to build dispatchable generation to ensure there will always be enough power. That's why this [market redesign] work that we're embarking on is so important," Vegas added.

He and Lake both used a new message in pointing to the continued growth in ERCOT's demand. They said Texas is adding a city the size of Corpus Christi — the eighth largest in the state at 317,863, according to the 2020 census — each year, placing additional pressure on developing generation resources.

The PUC's proposed market designs rely on adding dispatchable thermal resources over intermittent renewable resources.

"We have the same amount of reliable dispatchable resources with no target, no reliability standard, which is a key part of the reforms that this commission has evaluated and discussed," Lake said. "It's getting harder and harder to do this, because we have more people … this is a long-term problem, the lack of a reliable reliability standard, but the future is coming."

ERCOT last week also released its biannual capacity, demand and reserve *report*. It forecasts a summer peak demand of 82.7 GW, which would be a new record, and a winter peak of 69.4 GW.

The grid operator said next summer's planning reserve margin will be 22.2%, a 14-point drop from the 36.2% margin in the May 2022 CDR report. ■

ERCOT says it has enough capacity for its control room to meet peak demand this winter, assuming typical conditions. | © *RTO Insider LLC*

ISO-NE News

NECEC Scores Another Victory in Maine's Highest Court

By Sam Mintz

Maine's high court last week issued another favorable ruling for the New England Clean Energy Connect (NECEC) transmission project, increasing the possibility that the contentious line will be resurrected.

The decision by the state's Supreme Judicial Court marks the second in favor of the project since August, when it found that a referendum blocking the project may have been unconstitutional. (See *Maine Court Ruling Gives New Life to Contentious Transmission Line*.)

In the Nov. 29 *order*, the court reversed an August 2021 decision by the state's Business and Consumer Court to vacate a lease agreement for public lands between the Maine Bureau of Parks and Land (BPL) and Central Maine Power, NECEC's developer.

The court said that the BPL had followed the appropriate process in approving the lease, and found that Question 1, the referendum Maine voters approved in 2021 to oppose the project, had not vacated the lease.

"Because we conclude that the evidence contained in the record is sufficient, we see no reason to impose a further burden on the parties' time and resources by remanding for the Bureau to take further evidence," the five-judge panel wrote. "We conclude that the record establishes that the Bureau acted within its constitutional and statutory authority in granting the 2020 lease."

Together, last week's ruling and the August one mark significant victories that could put the project back on track.

A portion of the right of way for the New England Clean Energy Connect transmission line | *Roger Merchant*

"We think these two decisions have resuscitated the viability of the transmission project," ClearView Energy Partners said in a note to clients.

A legal fight over Question 1 will continue, with the Business and Consumer Court set to hear more arguments in April as to "whether or not CMP had vested rights to complete construction of transmission line," according to ClearView.

Depending on how that decision goes, CMP could restart construction as early as mid-2023, or face the prospect of having to make another appeal to the state's highest court.

"Today's ruling by the Law Court is yet another step in the right direction for Maine's renewable energy future," Scott Mahoney, senior vice president at CMP parent company Avangrid, said in a statement.

NECEC proponents have been arguing for years that the project is necessary to transmit electricity from hydro plants in Quebec down through Maine and into Massachusetts.

"The serious need for the NECEC project to reduce our reliance on fossil fuels, combat climate change, and lower regional energy prices remains unchanged," Mahoney said. ■

ISO-NE News

Climate Activists Take Over Small Piece of ISO-NE

By Sam Mintz

Climate activists managed to successfully take over a small piece of ISO-NE last week, winning control of a significant portion of the committee that controls the grid operator's official platform for interacting with the public.

Six activists organized by the anti-fossil fuel group No Coal No Gas were elected to two-year terms on the Consumer Liaison Group's (CLG) Coordinating Committee on Wednesday, securing a say in how the group operates, as ISO-NE officials looked on with what one attendee described as "grim" faces.

While the CLG carries little formal power, it's an important (and FERC-mandated) piece of how the grid operator communicates with the public. CLG holds four meetings a year, which provide a rare opportunity for the public to hear from and interact with high-level officials at ISO-NE and other key energy policymakers in the region.

Climate advocacy groups in New England have criticized how ISO-NE conducts its work, calling out the organization for policies they say are maintaining the grip of fossil fuels on the region's grid and hampering the clean energy transition.

No Coal No Gas built support for a slate of candidates and encouraged its members to attend last week's meeting and vote. More than 100 members of the advocacy group attended the meeting.

Nathan Phillips, a Boston University ecologist from Newton, Massachusetts, was one of the activists who was elected.

"It was the incredible feeling of being in the belly of the beast but having a hundred friends who had your back," he told *RTO Insider*. "It felt like democracy. It felt like people power."

No Coal No Gas laid out its plan in the weeks before the meeting in emails to members.

"We believe that the CLG could be a more productive forum and a space to build power among communities and ratepayers from across New England who are advocating for themselves regarding electricity (how it is generated, the cost, how the markets are structured)," the group wrote.

Climate activists took over the ISO-NE Consumer Liaison Group meeting last week and elected their members to the forum's coordinating committee. | *No Coal No Gas*

The group's priorities include more closely connecting CLG's work to people in New England who are, for example, struggling to pay their energy bills.

If they have their way, the forum's name might also change.

"I think it should be called the Ratepayer Liaison Group," said Phillips "It became apparent to me in the meeting, the words and the language matter."

To him, the term "ratepayers" gives more agency and power to the people it's describing than "consumers."

"Until now, the CLG has mostly been a space where ISO-NE presents to the public about what they are doing. There has been little actual input from the public, and even less from everyday ratepayers and environmental justice communities," No Coal No Gas told its members ahead of the meeting.

The other activists elected were Sonja Birthisel, a University of Maine researcher and nonprofit director; Kendra Ford, a Unitarian Universalist minister from New Hampshire who recently made a strong impression at ISO-NE's public board meeting; Regine Spector, an associate political science director at the University of Massachusetts, Amherst; Ian McDonald, an activist from Killingly, Conn.; and Jacob Powsner, co-owner of a farm in Rutland, Vt.

Two incumbents were ousted from the committee: Associated Industries of Massachusetts executive Robert Rio and former Harvard University energy supply official Mary Smith.

Along with allies from state consumer advocacy offices and environmental groups who make up several incumbents on the committee, the group pushing for change has gained a majority.

"It will now be much harder for ISO New England to keep the CLG from getting feisty," wrote Donald Kreis, New Hampshire Consumer Advocate and an incumbent who was re-elected. (Kreis has called for the CLG to be abolished altogether.)

ISO-NE spokesperson Matt Kakley said in an email to *RTO Insider* that the grid operator is "pleased to see the increased interest in the Consumer Liaison Group and hope people continue to attend meetings, gain insight into the regional energy landscape, and engage in the discussions." ■

MISO News

‘Conceptual’ Tx Planning Map Troubles MISO Members

RTO also Testing Benefit Ideas for New LRTP Cost Allocation

By Amanda Durish Cook

CARMEL, Ind. — MISO sparked strong reactions from stakeholders last week when it fired up the second phase of its long-range transmission plan (LRTP) by debuting a theoretical map of projects.

In a presentation to MISO's Planning Advisory Committee, the RTO's Senior Director of Transmission Planning Laura Rauch revealed a "conceptual map" of possible projects that may arise from a second attempt at a long-range analysis.

Some members were startled by the potential scope of the RTO's ambitions.

The possibilities for MISO Midwest include a crisscrossing system of new 345-kV lines, a network of 765-kV lines, a handful of 138-kV lines and even one HVDC line across Lake Michigan and another spanning North Dakota and Minnesota.

MISO's first $10 billion LRTP portfolio was also confined to MISO Midwest. The RTO doesn't plan to address MISO South needs until the third leg of its long-range transmission planning. (See *MISO Board Approves $10B in Long-range Tx Projects*.)

Rauch cautioned that MISO's conceptual map does not represent what a final portfolio would look like.

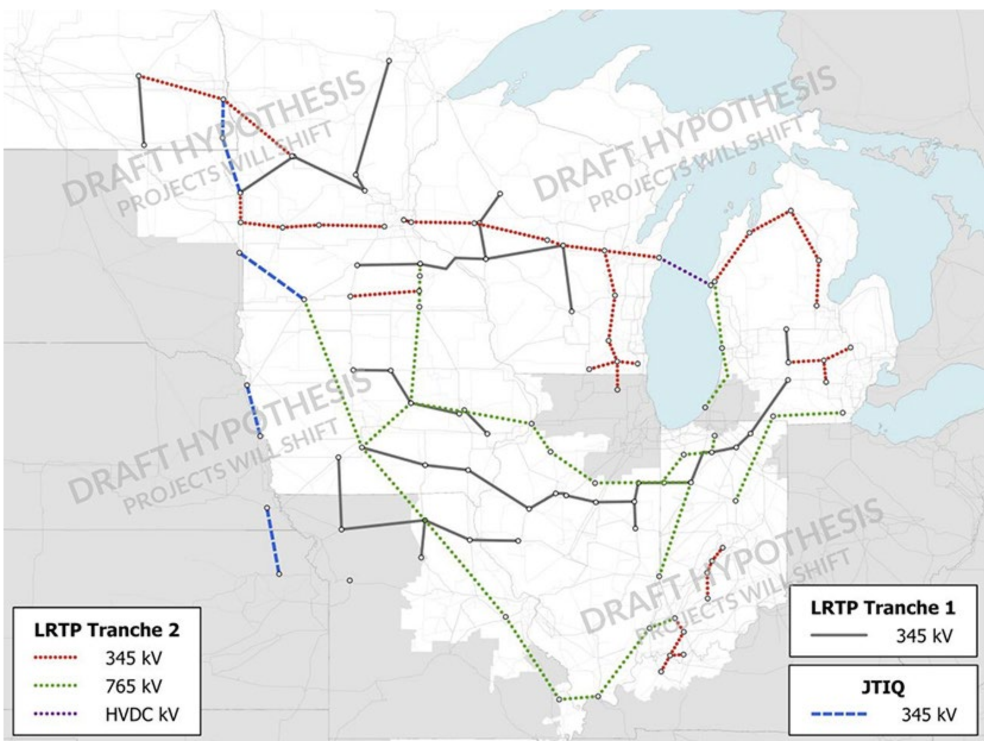
"This is a starting point, not an ending point," she said, adding that the line routes are educated guesses because MISO doesn't yet know how siting will play out.

"I'm sure there are things on this map that we will not want to analyze. I'm sure there are some substations that cannot handle … the magnitude of transmission," she said.

Rauch said it's still an open question whether the second LRTP cycle should include 765-kV and dispatchable HVDC lines.

Some stakeholders said they were taken aback by the scale of MISO's envisioned second LRTP.

"When you throw this slide up, this is very expensive, what's on here. Much more expensive than tranche one," said Jim Dauphinais, an attorney for the Coalition of Midwest Transmission Customers.



A narrowed-down concept map of possible lines under MISO's second LRTP portfolio | *MISO*

Rauch said the map could potentially be the "size of the answer," but added that the resulting portfolio could be smaller.

WEC Energy Group's Chris Plante called the map "uncharted territory" and said it was premature for MISO to publish the map before it ran analyses. Plante also said that the map doesn't include some lines utilities deemed necessary. He cautioned against sharing the map with MISO's Board of Directors this week at its quarterly meeting in Orlando, Fla.

Other stakeholders said MISO's release of the map might preclude consideration of other necessary transmission solutions that should be included in the second LRTP.

"I understand where you're coming from. At the end of the day, the analysis will win out," Rauch said. "This is going to be a long ride based on analysis. … Our intention was not to say we must do everything."

While acknowledging that the release of the map may have been a "messy" way of broaching the issue, Rauch said it's necessary to prepare stakeholders for MISO's future system needs. She added that stakeholder LRTP workshops in 2023 will cover the RTO's reasoning behind the hypothetical map of lines.

Rauch said MISO is building models to prepare for the second portfolio recommendation in 2023.

"We're seeing member plans accelerating. We'll continue to work through the futures and reflect that," she told stakeholders.

The RTO is updating the data behind its three, 20-year transmission planning futures in time for more long-range transmission planning and work on the 2023 Transmission Expansion Plan (MTEP 23).

Changes will include revised state and member decarbonization goals, resource retirements, resource additions based on its interconnection queue, accredited capacity amounts, and capital, operating and fuel costs. MISO did not alter the 20-year load forecast behind the three planning futures.

So far, MISO has only shared preliminary information on its moderate, second future. The RTO said it foresees 270 GW of new resources and has 115 GW of resource retirements. It also anticipates a 90% reduction in emissions by 2042, faster than it previously projected.

MISO News

The grid operator plans to share estimates from its conservative Future 1 and aggressive Future 3 next spring.

The second planning future will serve as the "focal point" for the lines MISO will plan under the second LRTP, Rauch said.

Zeroing in on Cost Allocation

A day before stakeholders got a glimpse of MISO's controversial planning map, they heard how MISO continues to assess how to develop a more targeted cost sharing methodology for LRTP projects.

Speaking at a stakeholder meeting on Nov. 28, cost allocation specialist Milica Geissler said the RTO will analyze whether it can allocate transmission costs by relying on more granular measures of identifying who benefits — and what the benefits are.

Milica Geissler, MISO | © RTO Insider LLC

Geissler said MISO will examine the subregional benefits of preventing load shed, meeting NERC criteria, weathering extreme events, furthering state decarbonization goals and increasing transfer capability.

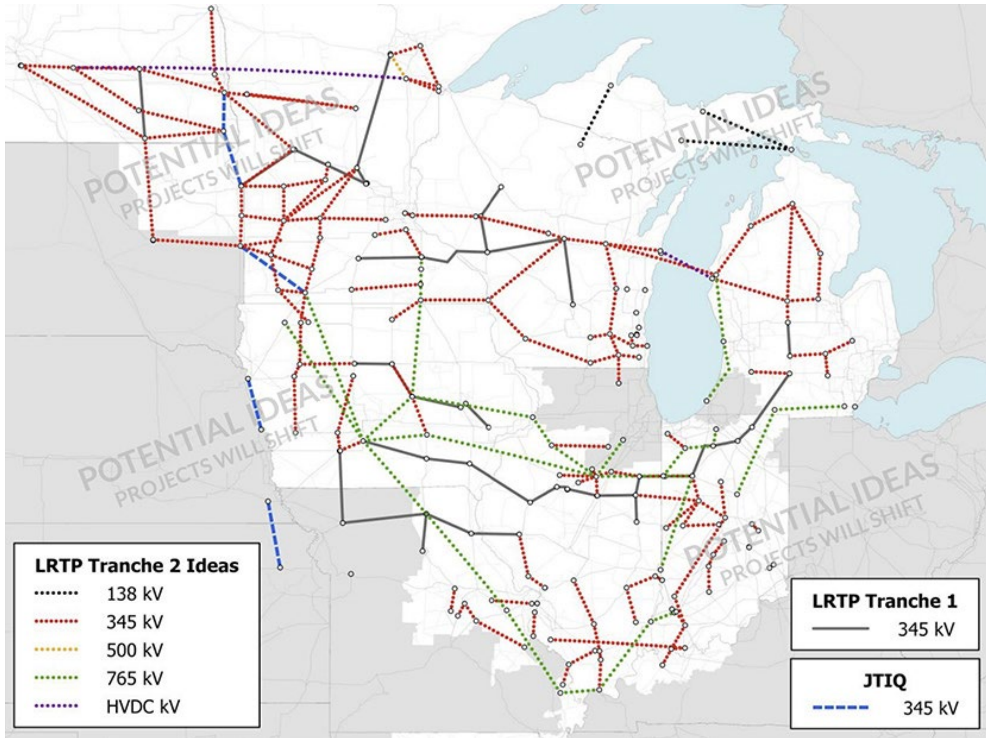
At the local zonal level, the RTO will test the benefits of avoided transmission investment, congestion and fuel savings, improved operating reserves and savings associated with resource adequacy. It will not test for any benefits on a footprint-wide basis because of its Midwest-South transfer constraint.

Some stakeholders argued that there's too much overlap among the factors being considered to identify standalone benefits.

Plante said projecting some of the benefits into the future is akin "to throwing a dart in a blackened room" because benefits change over time and MISO lacks insight into future resource siting and expansion.

Clean Grid Alliance's Natalie McIntire said MISO shouldn't assume that the Midwest and South regions are unable to help each other during extreme events. The RTO's Director of Cost Allocation and Competitive Transmission Jeremiah Doner said that while such benefits aren't "zero," they're not enough to measure on a footprint-wide basis.

Mississippi Public Service Commission attorney David Carr encouraged MISO to consider that including decarbonization benefits might make it more difficult for some projects to get approval from certain utility commissions.



All line ideas considered under MISO's second LRTP portfolio| *MISO*

Geissler said MISO is at this point only pondering the benefits and hasn't determined which ones will make the final cut. She added that the RTO isn't willing to apply any proposed changes to projects already in progress, saying it "finds a lot of value" in current allocations.

MISO is using a 100% postage stamp to load rate for the first two cycles of projects coming out of its LRTP studies, with those costs confined to MISO Midwest. (See *FERC OKs MISO's Bifurcated Cost-allocation Tx Design*.) But a new cost allocation approach that considers more beneficiaries could be applied to upcoming planning for the South region.

Carr said MISO should re-examine the assumption that load bear the "entirety" of long-range transmission costs. He made the argument in light of Montana-Dakota Utilities' suggestion that new intermittent generation, in addition to load, should bear a portion of LRTP costs. (See *MISO Gathering Stakeholder Input on LRTP Cost Allocation*.)

"Transmission costs are a much larger share of customers' bills. This situation is untenable," Carr said.

Carr also pointed out that years ago, MISO South didn't have any input in the postage stamp cost allocation.

Some stakeholders have voiced concerns about disparate treatment between LRTP portfolios, saying a different cost allocation for projects concerning MISO South will violate FERC's requirement that the same class of projects should not be subject to different allocations.

In October, Geissler said planners were wrestling with how to assign an evolving cost allocation when beneficiaries of a line change over time. Some stakeholders have requested that MISO find a way to identify and mete out costs to new beneficiaries over time.

"I'm very thankful for the 2011 portfolio of projects," Geissler said, referring to MISO's Multi-Value Projects approved a decade ago. She said those projects show how benefit-to-cost ratios either increased or decreased over time depending on the transmission pricing zone.

"They change in a pattern that isn't necessarily obvious," Geissler said of benefits. She said those fluctuations mean that future beneficiaries might be difficult to predict over time.

However, stakeholders said the zones that over time realized the most benefits from the 2011 portfolio contained the most wind generation. ■

MISO News

FERC Must Clarify MISO Tx Funding Decision, DC Circuit Finds

Commission's Rulings not 'Reasonably Explained,' Court Says

By Robert Mullin

FERC must better explain its 2019 decision to give MISO transmission owners unilateral authority to finance upgrades needed to interconnect new generation, the D.C. Circuit Court of Appeals ruled last week.

The proceeding was "the latest episode in a long-running dispute over how to fund upgrades to power lines," Judge Justin R. Walker wrote in the decision issued Friday (*20-1453*).

The details in the case extend back to 2015, when Otter Tail Power filed a complaint with FERC challenging MISO's policy of providing "direct" transmission owners with unilateral authority to decide whether to initially fund a needed upgrade — and later collect the costs from the interconnecting generator — or allow the generator to pay the costs up front. Otter Tail contended that while direct TOs exercised that privilege, operators of affected systems further downstream ("indirect" TOs) enjoyed no such option, resulting in differential treatment.

In a decision issued June 2015 (ER14-2464), FERC agreed with Otter Tail, but rather than extending the right of unilateral initial funding to TOs indirectly affected by an interconnection, it instituted a proceeding under Federal Power Act Section 206 directing MISO to either remove the unilateral option or explain why it shouldn't. (See *FERC: MISO Gen Agreement Allows Overcharging*.)

The D.C. Circuit vacated FERC's decision in 2018 in *Ameren Services Co. v. FERC*, saying the commission hadn't considered complaints from Ameren and five other TOs that claimed the policy forced them to accept "risk-bearing additions to their network with zero return" and essentially act as "nonprofit managers" of network "appendages."

The decision in *Ameren* "also held that FERC should have considered that its decision could force transmission owners to incur the financial risks of generator-funded upgrades without the opportunity for a profit," the court noted in Friday's ruling. "We declined to decide whether those enterprise-risk concerns required a particular result until FERC 'developed a record by considering' them."

The case was then remanded to FERC, which in 2019 *reinstated* TO funding rights and extended them to indirect owners, a decision the commission affirmed the following year after a protest by the American Wind Energy Association (later renamed the American Clean Power Association (ACP)) (EL15-68, *et al.*). (See *FERC Upholds MISO Self-fund Order, Glick Dissents*.)

MISO transmission lines | *Great Plains Institute*

The commission had also made its decision retroactive, forcing the renegotiation of several generator interconnection agreements between 2015 and 2018. (See *FERC OKs MISO Agreements Following TO Funding Ruling*.)

'Plausible Reasons' for Concern

In the case decided by the D.C. Circuit on Friday, the ACP petitioned the court to review FERC's orders, arguing that the commission had: failed to follow the *Ameren* decision's command to "develop a record" of enterprise risks for TOs; acted in an arbitrary and capricious manner by giving TOs unilateral funding authority; and erred in making its 2019 decision retroactive.

The court dismissed the third argument, saying that its jurisdiction only extends to arguments that a party raised in a rehearing application to FERC, "unless there is reasonable ground for failure to do so," points that ACP failed to argue.

Addressing ACP's first argument, the court found that FERC did comply with the *Ameren* remand order.

There, we told FERC to '[develop] a record by considering' the transmission owners' enterprise-risk argument," the court wrote. "That instruction suggested no particular briefing. Nor did it demand any additional evidence for a record that was already voluminous. Rather, it required nothing more than FERC 'considering' the enterprise-risk argument and putting that consideration on the 'record' for our review.

"On remand, FERC did just that: It considered the enterprise-risk argument and rendered a decision on its merits in the record for us to review."

But the court did agree with ACP's second argument, ruling that FERC's decision to grant unilateral funding authority to all TOs failed to satisfy the "arbitrary and capricious" standard in the Administrative Procedures Act.

"Although FERC's decision may ultimately prove to be 'reasonable,' it was not 'reasonably explained,'" the court said.

The court noted that ACP did not "seriously dispute" FERC's determination that, under the FPA, direct and indirect TOs should receive similar treatment with respect to upgraded funding. Instead, it argued that the commission violated the APA "by not adequately explaining its decision to solve that problem by giving unilateral funding authority to all transmission owners, rather than by denying unilateral funding authority to all transmission owners."

The court said it agreed with ACP that FERC failed to reasonably explain its decision: "In particular, it gave short shrift to the petitioner's concern that transmission owners might discriminate in favor of generators they own."

In proceedings before FERC, the court noted, ACP provided "plausible reasons" for that concern, having pointed out that many TOs in MISO also own generators, providing a competitive motive to discriminate against other generators. And while FERC acknowledged that concern, it also concluded that concerns about potential discrimination did not outweigh the TOs' enterprise-risk concerns.

FERC had argued that ACP did not "show why the ability of [generators] to challenge costs before the commission, a point on which the court relied, is inadequate to address any concerns with potential undue discrimination."

But the court pointed to "something important missing from FERC's orders: an assessment of the risk of discrimination and an explanation of why individualized proceedings provide generators with sufficient protection against that risk."

In oral arguments, the court noted, counsel for intervenors supporting FERC "gave a relatively detailed assessment and explanation" of why the current regulatory regime should alleviate the risk of TOs giving preferential treatment to their own generation.

But FERC's orders had failed to do that, it said.

"FERC had the chance to explain itself at two different steps in its proceedings," the court said Friday. "It could have done so when it found that the unilateral funding option was not unjust or discriminatory, or later when it remedied the disparity between direct and indirect transmission owners in the Otter Tail proceeding. ...

"We therefore remand for FERC to adequately explain its decision," the court concluded. "But we do so without vacating FERC's orders 'because there seems to be a significant possibility that [FERC] may find an adequate explanation for its actions, and, in any event, it appears that the consequences of its current ruling can be unraveled if it fails to.'" ■

MISO News

Sunflower's New CEO Hillman Looks Back on MISO Tenure

By Amanda Durish Cook

Todd Hillman, MISO | *MISO*

Todd Hillman, currently MISO's senior vice president and chief customer officer, is ending his nearly 20-year stretch with the grid operator and will become Sunflower Electric Power's new CEO next year.

Sunflower's board of directors on Nov. 21 *named* Hillman as its new CEO following a nationwide search. Hillman will succeed departing CEO Stuart Lowry.

Steve Epperson, CEO of Pioneer Electric Cooperative and Southern Pioneer Electric Co., two of Sunflower's seven distribution member-owners, said Hillman is a "best fit" for Sunflower.

"I see great teamwork, collaboration and courageous decisions in our future and am confident that Mr. Hillman will deliver," Epperson said in a press release.

At MISO, Hillman was responsible for customer relations, including member and regulatory relationships, and managing training, facilities and the RTO's call center.

Hillman said it will be "bittersweet" leaving the organization. He joined MISO in 2004 as it prepared to launch its energy markets in April 2005.

"Imagine 100 employees, give or take. It was all-hands-on deck," Hillman said in an interview with *RTO Insider*. "I just remember so much happening, and it was going so fast, and everyone was working on everything."

MISO currently has about 950 employees.

Hillman said his first title with the grid operator was the generic "executive director."

"We weren't quite sure what the role meant yet," he said.

Hillman joined the RTO after a stint at Reliant Energy's offices in the Netherlands, where he managed various electricity, natural gas and transmission contracts. While there, he also established a European satellite office in Frankfurt, Germany. After Reliant's sale of its Dutch operations, he returned stateside for Reliant before landing at MISO's Carmel, Ind., headquarters.

"So naturally after working in Europe, Carmel, Indiana, is the next logical step," he said.

"Todd's contributions to MISO have been unbelievable," MISO CEO John Bear said during an executive update Nov. 28. He thanked Hillman for his dedication in integrating the MISO South region.

Hillman said MISO's successful integration of Entergy as MISO South in 2013 ranks among its greatest achievements during his tenure. He described the work as "climbing Mt. Everest with one hand tied behind your back."

"It took a village to do that," he reflected.

Hillman said he considers the grid operator's employee culture as his greatest personal accomplishment. He said he's proud of the strides made on workplace diversity, equity and inclusion. He pointed to the creation of dedicated resource groups for employees who are also caregivers or veterans and employees' annual $1 million in contributions to the Make-A-Wish Foundation.

"I look back, and I think about the culture," Hillman said.

He said MISO today allows its employees to be creative and thrive in an industry that "isn't smooth sailing."

Hillman said MISO's endeavor to attract and retain talent must continue. However, he said MISO is making progress and voiced confidence in Allegra Nottage, the RTO's first chief diversity officer. (See *MISO Installs First Diversity Officer* and "High employee turnover concerns leadership," *MISO Board Week Briefs: Sept. 12-15, 2022*.)

Hillman said MISO has a "huge opportunity to reset the turmoil" wrought by the Covid-19 pandemic and the Great Resignation.

"I feel like it's a work in progress, but I know I leave it in great hands," he said.

Hillman remembered challenging times during MISO's early days, when Ohio and Kentucky members departed the footprint as former CEO James Torgerson also announced his exit in 2008.

"Imagine you're having all this turmoil against a senior leadership change," Hillman said.

Hillman said in all, MISO lost 7% to 10% of the footprint but gained roughly 30% in service territory with a spate of new memberships that began with MidAmerican Energy's entry in 2009.

"So, we lost members, but then we had more members come on [within] a few years," he said.

Hillman also said he has thought about his impending transition from MISO to SPP, where Kansas-based Sunflower is a member. The two RTOs attempted to merge last decade and remained rivals until recently.

"I promise I'm going to be a very good stakeholder," he said. "I know how tough it is, so I want to be a help."

Hillman said he's encouraged by the RTOs' collaboration in recent years and said he will place his Sunflower hat on and will advocate for his utility. "As it gets tougher in the business, the more those relationships can improve," he said.

Hillman said he's taking three important lessons learned from his time at MISO to Kansas.

"You always assume noble intent with anyone you're working with," he said. "Very few times are there issues that are black and white, and you can't get the ball across the line. We have to figure out how to get that [assumption of] noble intent on both sides up across the industry."

He said he plans on listening to all sides of an issue, something that's served him well working with MISO's 11 sectors and their differing viewpoints. He also said he will always remember that people are responsible for the electric industry's operations and progress.

"This is very complex work at the end of the day. And I always remember that there are people behind it," Hillman said.

He said he's excited about Sunflower's "main street" element and meeting customers. Hillman joked that he's equally excited to "serve just one state," instead of the 15 in MISO's footprint.

Hillman said he's "learned from the best" from MISO and its members and said he's taking those leadership templates with him to Sunflower.

"People ask me, 'Are you ready to be CEO?' I don't know, but I feel incredibly confident that if I can be anywhere near what they have done, I'll be all right." ■

MISO News

MISO Adding Near-term Congestion Study to MTEP

By Amanda Durish Cook

CARMEL, Ind. — MISO said last week that it will add an informational study on near-term transmission congestion to its 2023 transmission-planning cycle.

However, the study is unlikely to result in any cost-shared projects.

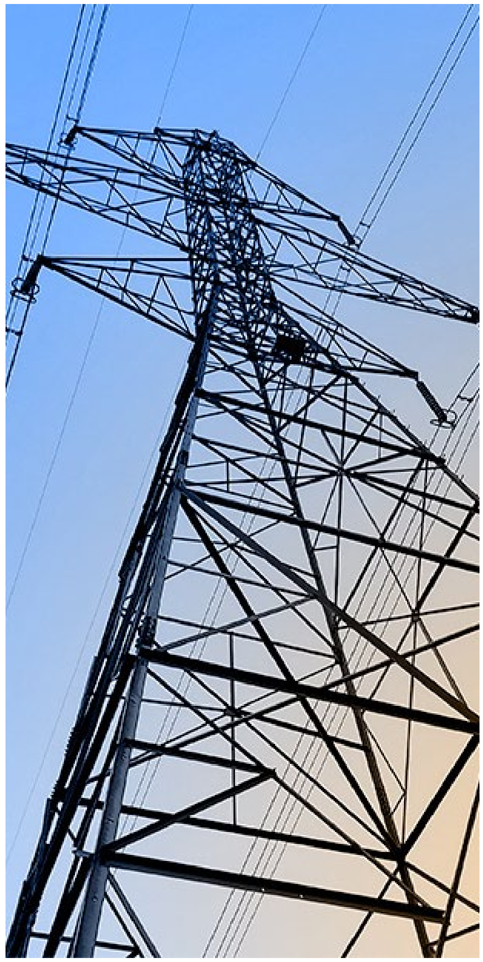
Speaking during a Planning Advisory Committee meeting Nov. 29, MISO engineering adviser Ben Stearney said the RTO will use near-term economic models to examine congestion up to five years out. MISO typically studies congestion in 10- to 15-year-out modeling, but stakeholders have said congestion is increasing and deserves attention and relief projects.

"I do want to emphasize that MISO will not be proposing any new cost-allocation mechanisms or project types in concert with this analysis," Stearney said, adding that any identified projects will be taken up and funded only by market participants.

He said staff used production cost models to determine that a new study for the 2023 Transmission Expansion Plan (MTEP 23) "could provide valuable insight into current system congestion as well as inform parallel study efforts."

"We've done some investigation work, but we've never really done a study like this," Stearney said. A near-term congestion study could help inform MISO's other MTEP modeling work, he said.

Stearney said the RTO's models were able to recreate some of the footprint's top binding constraints.



| © RTO Insider LLC

Energy consultant Kavita Maini said in her home base of Wisconsin, congestion is a persistent problem. She said it would be helpful for MISO to pinpoint projects that can mitigate congestion.

"Congestion is very real, and the Independent Market Monitor has spoken about it as well," Maini said.

Clean Grid Alliance's Natalie McIntire asked that the grid operator explore pathways beyond participant funding for possible projects emerging from the study. She asked staff not to foreclose the possibility that MISO could land on a project that fits the criteria of a market efficiency project.

"We're talking about congestion here that's costing consumers a lot of money," McIntire said.

MISO said last spring that it was mulling adding a class of smaller, congestion-relieving projects under its annual transmission planning cycle, inspired by its targeted market efficiency projects with PJM. (See *MISO Considers Adding Smaller Congestion Relief Projects*.)

The RTO later said it encountered modeling obstacles to adding a new study focused on solving near-term congestion. Staff said they had difficulty recreating some historical congestion in its planning models.

In October, Stearney said MISO needs to improve on how real-time congestion is captured in its modeling to identify worthwhile upgrades.

"MISO regional models are not tailored toward this type of analysis, so additional complications are expected," the grid operator said at the time. ■

MISO News

MISO Proposes Review of Improvement Ideas' 'Parking Lot'

By Amanda Durish Cook

CARMEL, Ind. — MISO is proposing a biennial review to reduce its "parking lot" list of improvement suggestions, although some stakeholders are putting up resistance.

"We'd like to make sure that good ideas don't go to the parking lot to linger indeterminately," Laura Rauch, senior director of transmission planning, said during a Market Subcommittee meeting Thursday

MISO's *parking lot* contains improvement ideas submitted to MISO through its issues-submission process. It has become a graveyard of shelved ideas, with some stakeholders complaining that their recommendations remain unaddressed. (See *MISO Pledges Review of On-hold Stakeholder Ideas*.)

The grid operator *said* it will clean up the parking lot and eliminate nearly 20 suggestions. In some cases, staff doesn't have a record of the stakeholder that originally submitted the idea or its full description.

The grid operator said it will use "active," "inactive," and "closed" to label the idea list. "Closed" means MISO has no current plans to address the idea and it will fall off the list. Staff will work with stakeholders with inactive projects and determine their feasibility every two years.

Rauch pointed to a suggestion creating a universal resource participation model that has spent years in the parking lot. MISO doesn't distinguish market participation models by intermittency, energy storage and demand response, leading Rauch to term the suggestion "aspirational" and suggest it should be closed. Stakeholders could always revive the idea by submitting it again to the RTO.

Rauch also said there's some redundancy among the improvement recommendations.

"To me, this seems like another way MISO isn't allowing stakeholders to decide when an item doesn't need attention," Clean Grid Alliance's Natalie McIntire said.

Independent Market Monitor David Patton took umbrage with MISO's move to close his suggestion that a virtual spread product be created in the day-ahead market. It would allow participants to specify the maximum congestion between two points they are willing to pay in a virtual transaction.

Rauch said in this case, staff last delivered a presentation on a virtual spread product in 2012. She said MISO has no plans to address the issue.

Xcel Energy's Kari Hassler said she was concerned that the grid operator would put recommendations on the chopping block before it has completed its new market platform, which has been billed as being able to host more complex market products.

"We have a lot of projects that are pushed back and waiting in the wings until" MISO's new market platform is finished, Hassler said.

MISO plans to roll out its day-ahead market on the new, modular market platform next year. ■

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

MISO News

MISO Simpatico with Monitor's 2022 Market Recommendations

By Amanda Durish Cook

MISO control room | *MISO*

CARMEL, Ind. — MISO says it "largely agrees" with its Independent Market Monitor's five new market recommendations issued this year.

The IMM's annual State of the Market Report, released this summer, listed recommendations for promoting transmission reconfiguration plans, reducing out-of-market commitments, creating a future-looking dispatch model and ensuring MISO only pays for real load reductions. (See *MISO Monitor Prescribes 5 New Fixes in Annual Market Report*.)

The grid operator said it is actively working on three of the ideas, while the remaining two are on its list of five-year goals.

In reviewing the market performance in 2021, the Monitor said the RTO should:

- work with its transmission owners to identify and implement economic transmission reconfiguration plans to better manage congestion;
- evaluate and restructure its unit commitment process to reduce out-of-market commitments and ensure make-whole payments;
- develop a multihour, look-ahead dispatch and commitment model to better manage fluctuations in net load and decisions on when to use storage resources. Patton said, "as reliance on intermittent resources grows in MISO, the need to manage extraordinary fluctuations in net load will grow;"
- improve rules around demand participation in energy markets so that MISO only pays for load reductions that occur; and
- consider classifying load-modifying resource (LMR) curtailments as short-term demand in pricing models and the unit dispatch system.

The last recommendation stems from Patton's observation that LMRs are allowed to set real-time energy prices long after emergency conditions have passed. He said that's because of MISO's extended locational marginal pricing (ELMP) model respecting resources' ramp rates, which makes it impossible to replace a large volume of LMRs within a single dispatch interval.

Patton said the LMRs appear to be necessary and set prices "long after MISO's resources are sufficient to replace them by ramping up." He said that if MISO treats LMRs as an operating reserve demand in the ELMP model, it would eliminate the problem.

MISO said it has yet to begin work on the second stage of its look-ahead commitment tool or categorizing LMR curtailments under short-term demand for pricing purposes.

Zhaoxia Xie, with MISO's market design team, said staff may encounter some difficulty including LMR curtailments because short term reserves are priced systemwide or zonally, whereas LMRs are modeled at the more local nodal level. But she promised more evaluation on the issue Thursday during a Market Subcommittee meeting.

The RTO said it plans to augment its look ahead commitment tool in 2023 to improve commitment decisions. It said upgrades should reform its unit commitment processes with the added benefit of using storage resources to manage fluctuations in net load.

"This has been a hot topic between MISO and the IMM for a while," Xie said. She said staff is constantly evaluating improvements in its commitments process.

The grid operator agreed that it could use more stringent rules and procedures for demand participation "to avoid unjust payments." MISO said it may file tariff revisions with FERC after consulting with stakeholders.

Staff said they've been working since January with transmission owners to develop operating procedures for transmission reconfiguration. They will begin a reconfiguration process in 2023's first quarter to reduce congestion costs.

MISO's Tony Rowan said the procedure involves a market participant bringing a suggested economic reconfiguration to staff and relevant TOs, who will test the solution over 15 business days for reliability and economic impacts. If MISO and TOs agree the solution puts a dent in congestion without deteriorating system conditions, the reconfiguration plan will go into effect for an agreed-upon duration.

MISO also said it will maintain a public list of the footprint's top 10 most economically impacted constraints. ■

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MISO News

MISO Charts Course on Capacity Auction's Sloped Demand Curve

By Amanda Durish Cook

CARMEL, Ind. — MISO is releasing preliminary design details of a sloped demand curve in its capacity auction. Staff plans to use its planning reserve margin requirement as a middle point and adding and subtracting incremental amounts of capacity, measured by expected unserved energy.

Mike Robinson, MISO | *© RTO Insider LLC*

"It's going to be convex shaped," Mike Robinson, principal adviser of market design, told the Resource Adequacy Subcommittee Wednesday.

Robinson said MISO doesn't yet have exact values associated with the demand curve.

"We have preliminary numbers, and we're assessing them to make sure they pass the smell test and that they're reasonable," he said.

Reliability will be "foremost" in designing the curve's shape, Robinson said. He noted MISO wants a demand curve that encourages reliability while valuing capacity at market prices. A capacity glut would render sloped curve prices nil, Robinson said.

Independent Market Monitor David Patton said a sloped curve can prevent premature resource retirements and will raise revenues for most utilities. He said the curve will also "reduce financial risk and the volatility associated with overbuilding and underbuilding of capacity."

"You've all heard me talk about this for a decade or more," Patton told stakeholders.

The Organization of MISO States has largely endorsed MISO revising the vertical demand curve currently used in MISO's planning resource auction (PRA). (See *State Regulators Endorse New Demand Curve in MISO Capacity Auction*.)

OMS Executive Director Marcus Hawkins said support was "near unanimous."

Some stakeholders have said that setting a demand curve is challenging because utilities place differing value on additional capacity.

MISO said that to formulate a sloped demand curve, it will need to run analyses using the net cost of new entry (CONE), or an approximated revenue from capacity payments. To do this, the grid operator is proposing to use three years' worth of historical data to calculate inframarginal rents, the money used to cover generators' fixed costs. Net CONE will be calculated by subtracting inframarginal rents from CONE and using them to inform the curve's final shape.

Robinson said staff is trying to bend the curve in a way that supports net CONE over the long run.

Multiple stakeholders cautioned that inframarginal rents are rooted in market ambiguity and could set off lengthy stakeholder disagreements over what amount is appropriate.

A sloped curve will also have MISO adding what it calls an "advanced" fixed resource adequacy plan (FRAP) option.

Robinson said MISO isn't planning on changing any existing participation options for market participants; they can still opt out of the auction, make a FRAP, self-schedule resources, or purchase from the PRA.

"This is just another option here we want to make available," he said.

An advanced FRAP will require market participants to get their relevant regulator's approval, make a showing that they can meet their load obligations a month ahead of the auction, and commit to not taking offers in in the auction for a minimum of three consecutive years. Under an advanced FRAP, load-serving entities could sell their excess capacity provided it they have a certain, yet-undetermined percentage of capacity beyond their requirement.

Robinson said MISO won't allow partial advanced FRAPs as it does with run-of-the-mill FRAPs. "You're either fully in or fully out," he said.

Robinson said allowing a partial advanced FRAP would complicate the auction's algorithm. He also said a minimum commitment will discourage load-serving entities from "toggling in and out of the auction."

MISO will take stakeholder opinions on its early proposal through the end of the year.

A sloped demand curve in the capacity auction was top of mind during a late summer stakeholder idea exchange.

Bill Booth, a consultant to the Mississippi Public Service Commission, said he didn't see why a downward sloping demand curve is en *vogue* again. He said MISO's circumstances — being overwhelmingly comprised of vertically integrated utilities — haven't changed since a sloped demand curve was last contemplated and shot down five years ago. He said the RTO's excess capacity drying up is the only thing that's different.

Sloped demand curve discussion at the Nov. 30 Resource Adequacy Subcommittee | *© RTO Insider LLC*

"There's plenty of renewable generation trying to tie into the system, so I don't think we need to promote that," Booth said. "That's clear from the interconnection queue … but it might not be the generation we need for our circumstances."

He said decisions on fuel mixes are made at the state level and its naïve to hope that a demand curve's prices will spur more dispatchable resources. Booth suggested MISO's planning reserve margin requirement could be tailored to require a certain amount of dispatchable generation.

Hawkins argued that a capacity shortage isn't MISO's only issue. He said clearing prices in recent resource auctions have become increasingly volatile.

Julie Fedorchak, the North Dakota Public Service Commission's chair, said the RTO's capacity market "desperately" needs better market signals, and the demand curve is a tool toward improving them. She said that, candidly, she was "sick and tired" of some MISO members freeriding at the expense of her ratepayers.

MISO has committed to more frequent postings of preliminary capacity auction data. The grid operator will standardize the schedule of seasonal reserve requirements in zones to twice per month in mid-January.

The more frequent data shares are a response to stakeholders' asking staff to publish more regular updates ahead of the auction on its supply estimates and requirements. (See "Stakeholders Ask for Data Improvements," *MISO Promises Stakeholder Discussions on Capacity Auction Reform*.) ■

MISO News

MISO: 200 GW in New Capacity Necessary by 2041

By Amanda Durish Cook

CARMEL, Ind. — MISO said last week its members may need to build 200 GW in new installed capacity by 2041 to meet reserve requirements and achieve renewable targets and emissions-cutting goals, according to the RTO's annual regional resource assessment.

The grid operator used this year's report, which draws on members' public generation plans and MISO's own capacity expansion estimates, to repeat warnings of continuing capacity shortages and plead for more controllable generation. Staff said members may need to construct more than 100 GW of new capacity within the next 10 years alone to meet "publicly announced plans and goals in a reliable manner."

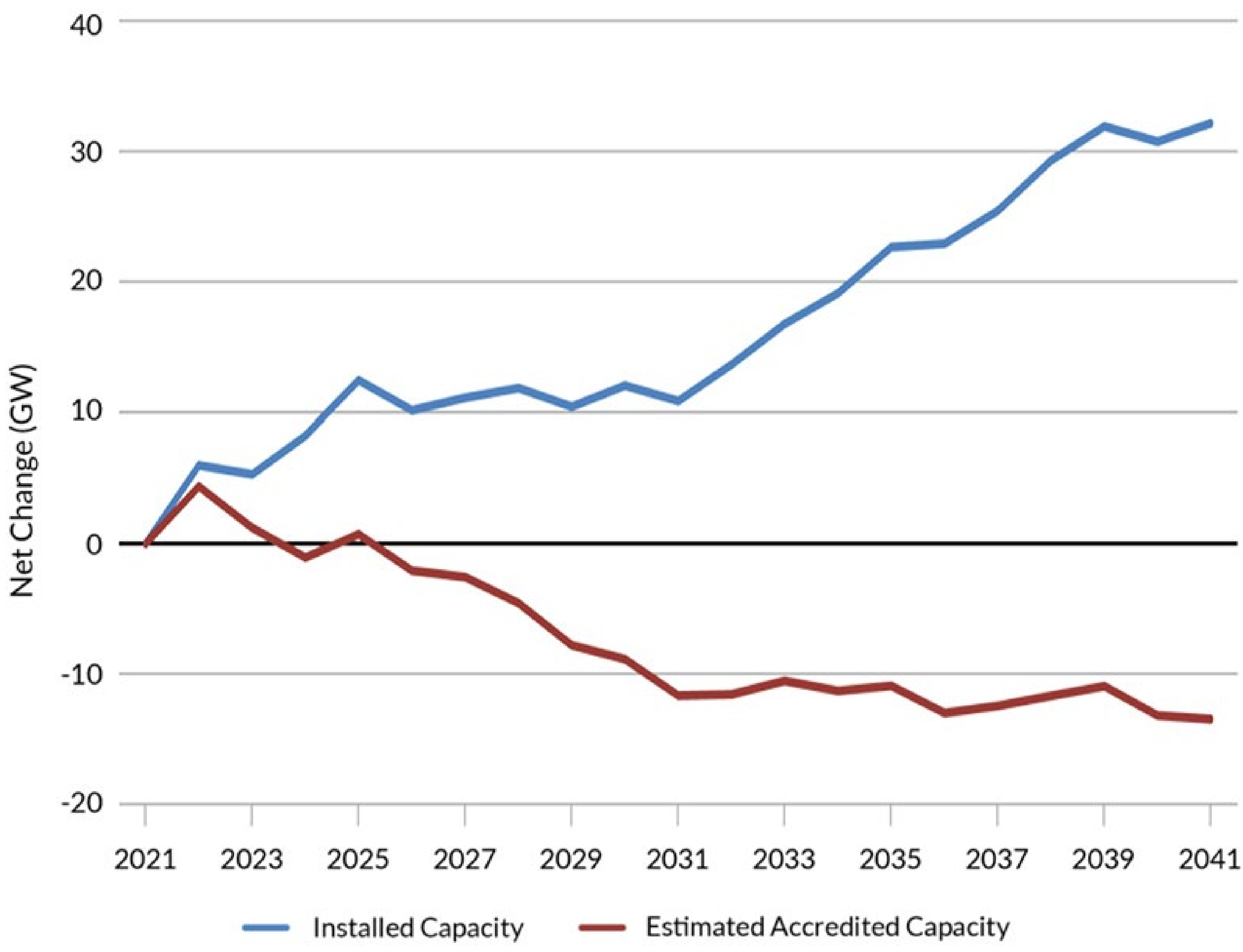
After the inaugural assessment in 2021, MISO said it would need to add 140 GW of new capacity over the next two decades to meet state carbon-reduction targets while also maintaining reliability. Carbon reduction goals have only become more aggressive in the last year, with utilities frequently revising net zero goals. (See *MISO Resource Assessment: 140 GW Needed Within 20 Years*.)

This year, MISO focused on accredited capacity numbers. Although it expects members to add 30 GW of net installed capacity by 2041, it said accredited capacity will be at least 10 GW lower than what is available today.

The RTO projects members will likely need to add 47 GW in accredited capacity above the 141 GW of planned and accredited existing resources it expects to have in 20 years. It has approximately 162 GW in total accredited capacity today.

MISO said it will likely approach 30% of its annual energy coming from renewables within five years, with penetration levels increasing by about 10% every five years.

Its modeling "indicates a continued near-term capacity risk, highlighting the urgent need for



Projected capacity change through 2041 | *MISO*

MISO News

coordinated resource planning and additional investment." Staff stressed that the assessment captures a snapshot in time that relies on publicly available resource planning and isn't necessarily MISO's future. They emphasized that MISO members do not produce "detailed" resource plans on a 20-year time horizon.

"In the absence of a coordinated transition plan, having a holistic assessment of our entire operating region is important for our members, policymakers and MISO as we all work to anticipate and manage the complex issues facing our industry," CEO John Bear said in a Wednesday *press release* accompanying the report.

According to the report, wind and solar generation will serve 60% of MISO's annual load by 2041, reducing emissions by nearly 80% relative to 2005 levels. The RTO said that generation mix will "sharply increase the complexity of reliably operating and planning the system."

The footprint will "have a much greater need for controllable ramp-up capability," MISO said. It said its short-duration ramp needs will increase three-fold from current levels by 2031, and four-fold by 2041.

MISO also said that by 2031, it will encounter resource adequacy risks in all seasons, not just summer. The grid operator said the risk will mostly be concentrated in the evenings when solar generation tapers off and wind generation is still ramping up.

The RTO found that as more solar capacity is added to the system, the capacity contribution of solar generation "is forecast to decline rapidly," while wind generation's contribution remains stable with additions.

"As the MISO region rapidly transitions to a decarbonized fleet, the system will become more interconnected and interdependent," Jordan Bakke, director of strategic insights and assessments, said. "The task of resource planning is becoming more complex and having a shared understanding of future trends and risks is necessary to ensure reliability."

MISO has a staggering amount of proposed capacity in the interconnection queue after fielding in September a record 171 GW of proposed renewable generation and storage projects from 956 requests. (See *MISO Insists it can Handle Record-setting Interconnection Queue*.)

The rub is MISO's supply of accredited capacity. And while capacity increases, its share of on-demand capacity is drying up.

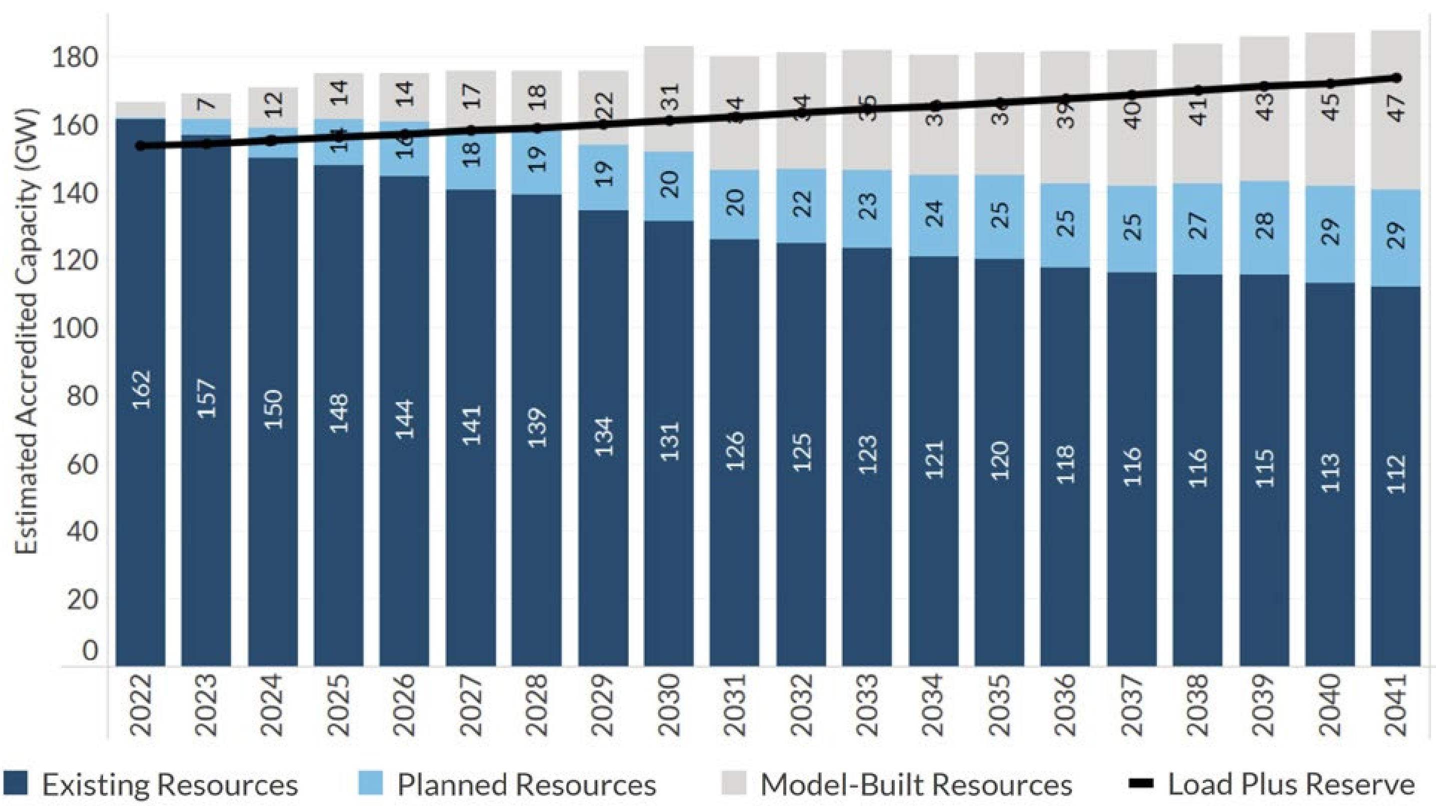
During a Nov. 10 stakeholder workshop, policy studies engineer Hilary Brown said members are largely planning investments in solar and wind capacity as they schedule more coal generation retirements.

"A one-for-one megawatt replacement is likely not sufficient," Brown said of members' plans.

She said MISO expects the near-term capacity risk to continue with the growing need for flexible resources to reinforce intermittent resources.

The RTO's system simulation showed it will likely need a yet-unknown combination of low-emission, high-capacity grid-enhancing technologies by 2030, including carbon capture and sequestration, small modular reactors, green hydrogen and long-duration energy storage.

Stakeholders have pressed MISO to provide a megawatt value of how much new storage it might need over the next 20 years. ■



Systemwide existing, planned, and needed resources | *MISO*

NYISO News

NYISO Management Committee Briefs

RENSSELAER, N.Y. — NYISO's Management Committee on Wednesday approved tariff revisions on credit rules for virtual transactions, the deliverability of "internal controllable" lines and transmission owners' right of first refusal. The committee also received briefings on the ISO's winter supply outlook and its updated Strategic Plan.

NYISO headquarters in Rensselaer, N.Y. | *NYISO*

Credit Requirements on Virtual Transactions

The MC approved the first *changes* since 2009 to the ISO's credit requirements for virtual transactions — bets on the price spread between the day-ahead-market (DAM) and the real-time market.

The 2009 changes distinguished for the first time between virtual load — offers to acquire energy in the DAM — and virtual supply, offers to provide energy. The rules varied credit requirements based on seasonal, time of day and zonal groupings to reflect their risk characteristics, using data from April 2005 forward.

The current rules break supply and demand credit requirements into four periods for weekday peak hours (HB7-22), and one each for nights and weekends/holidays. Under the proposed changes, virtual demand bids will have different requirements for summer, winter and shoulder months, with 28 distinct groupings. Virtual supply bids will be broken into 33 groupings, also reflecting the seasonal differences.

The proposal also would change the lookback period, giving one-third weight to data from the last year and two-thirds to the last five years.

NYISO said expected changes to its transmission system and resource mix over the next decade "provide support for shift to a shorter lookback period so that changes in real-time price variability are reflected in credit requirements without a long delay."

Virtual Supply

		Alternative 3	Alternative 1
One Year	Summer	OK	OK
	Winter	Far better	Far better
	Shoulder	OK	OK
	Overall	Favorable	Favorable
Five Year	Summer	Far better	OK
	Winter	Far better	OK
	Shoulder	Far better	Favorable
	Overall	Far better	Favorable
Current	Summer	Far better	Favorable
	Winter	Favorable	OK
	Shoulder	OK	OK
	Overall	Favorable	OK

Virtual Demand

		Alternative 3	Alternative 1
One Year	Summer	OK	OK
	Winter	Favorable	OK
	Shoulder	OK	OK
	Overall	Favorable	Favorable
Five Year	Summer	Far better	Favorable
	Winter	Favorable	OK
	Shoulder	Far better	Far better
	Overall	Far better	Favorable
Current	Summer	Far better	Far better
	Winter	Favorable	OK
	Shoulder	Favorable	Favorable
	Overall	Favorable	Favorable

Virtual supply and virtual demand positions show lookback comparisons. | *NYISO*

The ISO settled on the weighting to balance accuracy with responsiveness, said John Jucha, senior credit risk analyst. Longer lookback periods provide more data points and more accurate estimates but result in slower changes to credit requirements when system conditions and price volatility are changing rapidly. Shorter lookback periods allow quicker adjustments to credit requirements but can also result in dramatic changes not warranted by underlying conditions.

The proposed rules also would treat the ISO's transmission zones and proxy buses individually rather than the current practice, which sets one requirement for zones A to F and another for zones G to I. The ISO said it expected "significant benefits" immediately for zones A and F, with potential benefits for other zones in the future.

Also changed was the threshold for virtual supply positions, which will increase to the 98th percentile. The threshold remains unchanged at the 97th percentile for virtual demand positions.

The new rules will also apply to external transactions.

Pending approval by the Board of Directors, the ISO hopes to file the changes with FERC by April 2023 and deploy them in June.

NYISO Strategic Plan

NYISO *shared* its 2022 Strategic Plan, which highlighted its responsibilities, accomplishments and future goals, as well as how state and federal policies help drive the ISO's strategic objectives.

Executive Vice President Emilie Nelson said offshore wind represents the largest potential shift in New York's resource mix and that the state Climate Action Council's forthcoming final scoping plan will inform much of the ISO's future work. Energy security has become a growing concern as geopolitics impact global supplies, she added.

Nelson told stakeholders that NYISO has taken on more responsibilities, such as developing a reliability needs assessment, increasing stakeholder communications and tackling multifaceted issues like cybersecurity.

Bruce Bleiweis of DC Energy asked Nelson what letter grade the ISO would give itself as a "leader in the application of technology."

Nelson responded that NYISO performs at an "A" level.

Bleiweis disagreed, saying he and other stakeholders focused on the financial markets have been frustrated with their inability to win ISO backing for "relatively minor changes" to the transmission congestion contracts (TCC) market.

"We've been asking for certain changes to the TCC markets for six or eight years," he said, saying a "simple posting of data" calculated by the ISO "seems to become a [$500,000] project."

Bleiweis said his company doesn't face such "roadblocks" in the other organized markets. "Once a project is approved by stakeholders and the ISO, they seem to move forward relatively quickly."

Nelson said the ISO must make "difficult" tradeoffs between competing budget priorities.

Deliverability Rules

The MC approved *proposed* tariff language governing the deliverability of internal controllable lines (ICLs) such as Clean Path New York.

The rules would require a class year transmission project requesting capacity resource interconnection service for unforced capacity (UCAP) deliverability rights to be deliverable throughout the capacity region to which it proposes to inject energy and throughout the capacity region from which it proposes to withdraw energy.

Amanda Myott, NYISO market design specialist, said the ISO was proceeding with tariff revisions on the deliverability of ICLs before the rest of the ICL market design to ensure the changes apply to the class year 2023 deliverability analyses. (See "Ramp Limits on 'Internal Controllable' Lines," *NYISO Installed Capacity Working Group/Market Issues Working Group Briefs: Sept. 30, 2022*.)

The changes approved by the MC also affect tariff Attachment S regarding the calculation of UCAP deration factors in the class year deliverability studies and expedited studies.

Pending board approval, the ISO intends to submit the revisions to FERC in January.

ROFR 'Upgrades' Clarification

The MC approved *tariff changes* to codify TOs' right of first refusal (ROFR) on public policy transmission (PPT) projects, building on changes approved by FERC in March. (See *FERC Approves ROFR for NY Transmission Upgrades*.)

The March order only addressed upgrades that are part of a developer's proposed PPT project. The new proposal, presented by Stuart Caplan of Troutman Pepper, would extend the ROFR provisions to "network upgrade facilities" that are required as a result of the transmission interconnection process. (See *NY TOs Seek Clarification on ROFR for Upgrades*.)

Without the changes, TOs must engage in case-by-case bilateral negotiations and FERC filings, resulting in a more time consuming and less transparent process, Caplan said.

Subject to board and FERC approval, the changes would be effective for the Long Island offshore wind transmission project.

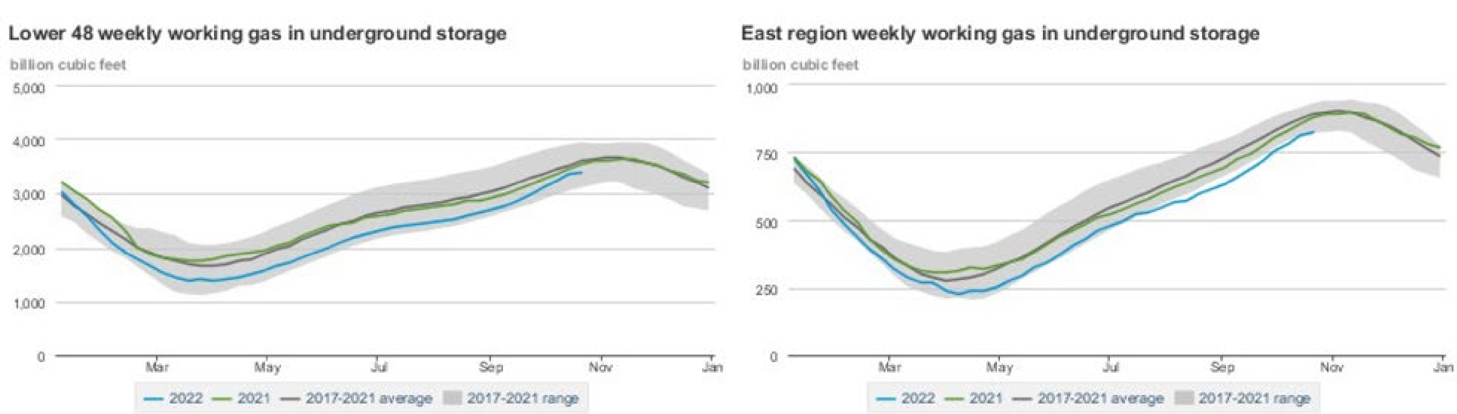
Winter Capacity Assessment

Natural gas storage levels are higher than anticipated thanks to a mild fall, but they are still lower than previous years, *according* to the ISO's winter capacity assessment.

Distillate fuel inventories are well below the five-year average capacity, but generating units are still receiving deliveries, and inventories are approximately 95% of last year's capacity, according to NYISO Vice President of Operations Aaron Markham.

Markham also shared that both the Sprainbrook-East Garden City Y49 line in Long Island and the Moses-Willis MW1 line would be taken out service this season for repairs. ■

— John Norris



Winter natural gas underground storage levels | *NYISO*

NYISO News

FERC Gives NYISO Until 2026 to Complete Order 2222 Compliance

FERC on Thursday approved NYISO's request for up to three more years to implement tariff revisions that will allow distributed energy resources in aggregations to provide all ancillary services they are capable of, in compliance with Order 2222 (*ER21-2460*).

NYISO last month *proposed* to extend the revisions' effective date from the fourth quarter this year to a "flexible" date of no later than Dec. 31, 2026, because of unexpected delays in developing and implementing the necessary software modifications.

The ISO said it will not necessarily need all of that time to complete the necessary work. It noted that it is still on track to implement the DER aggregation and participation models *accepted* by the commission in 2020 by the third quarter of 2023 and, as a result, may be able to start having aggregations participating in its markets far in advance of 2026.

It also said that in 2024 it will start deploying software that will automate much of the work that will at first be done manually by staff.

NYISO had earlier this year requested for more time to submit its Order 2222 compliance filing; as part of compliance with the order, each RTO and ISO was required to propose a date by which it could complete the necessary work integrating DERs into their markets. (See *NYISO Requests Extension, Clarification on Order 2222 Compliance*.)


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

In its brief order, FERC noted that no answers were filed in response to NYISO's request, approving it without further comment. ■

— John Norris

NYISO News

NYISO Considering Binding Multiphase Interconnection Studies to Cut Backlogs

By John Norris

RENSSELAER, N.Y. — NYISO officials said Wednesday they will begin stakeholder discussions early next year on revising the interconnection process to make it more efficient, calling it one of their top priorities for 2023.

Zach Smith, vice president at NYISO, *told* the Management Committee that the ISO is considering a "queue window-based approach," where each stage of the study would be more meaningful and potentially binding.

The new approach would replace the current three-step study structure, which includes an optional feasibility study and a non-binding system reliability impact study (SRIS) before the facilities study, which results in binding cost allocations.

Smith said the ISO envisions a "clustering approach" where projects are put into a study together to evaluate their joint impact. Smith emphasized, however, that this was simply a preview of what will be discussed with stakeholders and that nothing is settled.

Smith said the additional changes would require tariff revisions and FERC approval, unlike changes the ISO has already made — adding interconnection support liaisons and project managers; improving the interconnection portal; streamlining the SRIS — and ones in process — developing templates to shorten SIS reports and improving handling of material modification requests. (See *NYISO Identifies 35 Projects for Narrowed SRIS Scope*.)

The ISO expects to begin discussions in the MC, the Transmission Planning Advisory Subcommittee and Electric System Planning Working Group as soon as January and no later than February. "We do not intend to hold up on any improvements waiting" for an order from FERC's June Notice of Proposed Rulemaking on interconnection generator interconnection procedures and agreements (*RM22-14*), Smith said. (See *FERC Proposes Interconnection Process Overhaul*.)

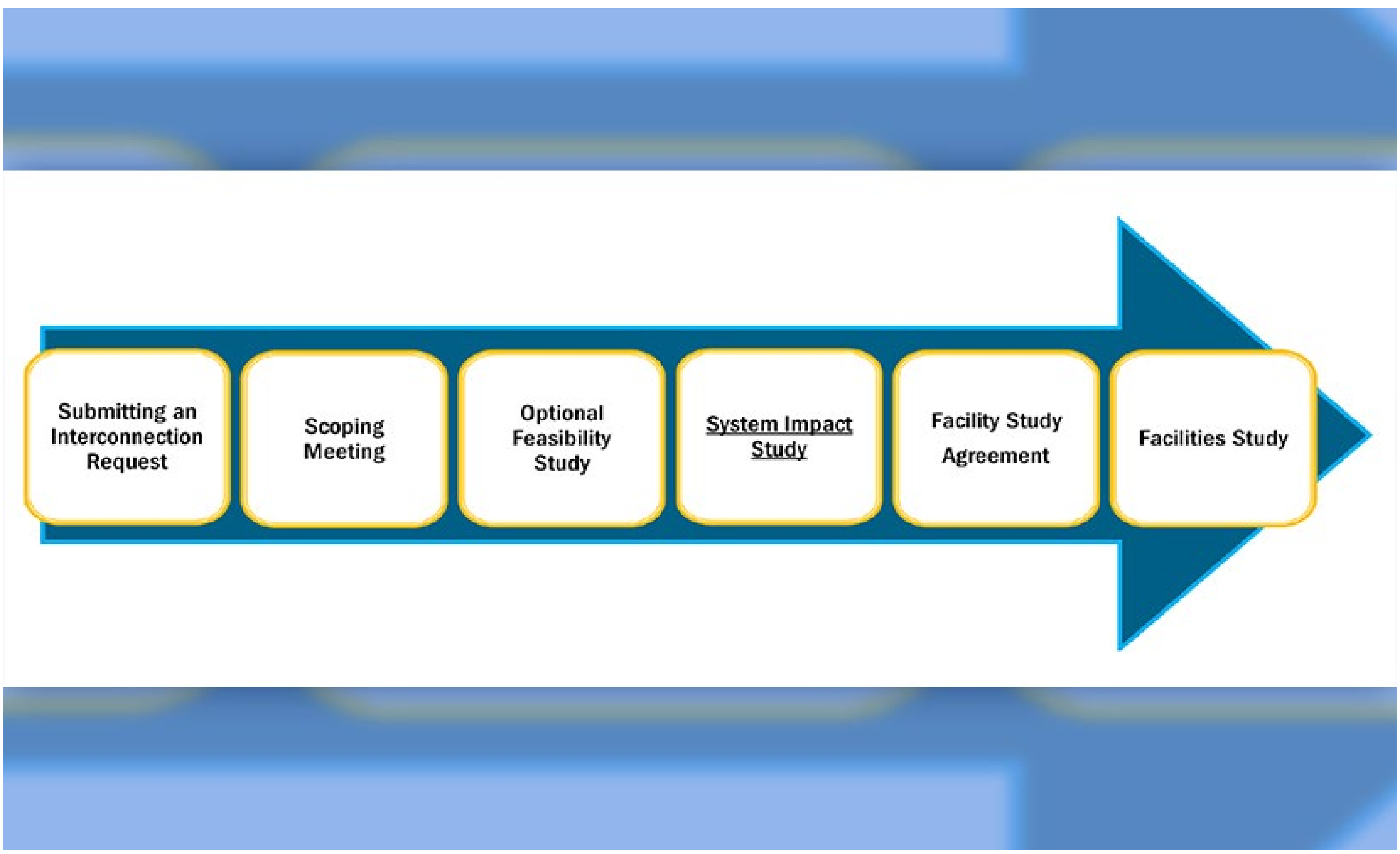
Smith said NYISO is acutely aware of potential tradeoffs stemming from pursuing faster methodologies but is committed to ensuring that project reliability is never sacrificed.

"Do you want speed or do you want flexibility?" Smith said. "One will have to be sacrificed for the other."

Smith added that it is important for FERC to maintain "independent entity variations" enabling RTOs to tailor solutions to their own regional problems.

CEO Rich Dewey said that the ISO is committed to addressing both the effectiveness of these processes and the customer communication around them. Dewey told stakeholders he understands trade-offs will occur as further changes are made to find the "sweet spot" between flexibility and efficiency.

Mark Reeder, representing the Alliance for Clean Energy New York, commended the ISO for its continued focus on improving the interconnection process: "That's greatly appreciated." ■



Interconnection procedures for large facility projects | *NYISO*

PJM News

FERC Approves PJM Plan to Speed Interconnection Queue

By Devin Leith-Yessian

FERC last week approved PJM's proposal to speed up its interconnection queue by handling requests through a new clustered approach that prioritizes projects that are ready to build (*ER22-2110*).

Under the *new paradigm*, PJM will shift away from its current first-come, first-served methodology to instead study new service requests with a first-ready, first-served approach that clusters proposed projects together to determine network impacts and allocate network upgrade costs. Much of the backlog of submitted projects will be grouped into transitional cycles, which are expected to be completed in the fourth quarter of 2026.

PJM Vice President of Planning Kenneth Seiler said the RTO sees FERC's Nov. 29 order as a win for interconnection customers, stakeholders and electric users by allowing projects to more quickly move through the queue and begin development. He credited the transparency and dialogue with stakeholders through the process of drafting the proposal with creating a solution that was accepted by the commission nearly unaltered.

"We're very happy with how FERC has come forward with this," Seiler said.

An Aug. 30 *deficiency notice* from the commission seeking more information from PJM did not affect the anticipated timeline for implementing the new transitional process, Seiler said, and staff will be discussing the next steps at today's Planning Committee meeting. (See *FERC Issues Deficiency Letter on PJM Queue Overhaul*.)

"I believe we're well on track to move forward," he said.

Signing off on last week's *order* were Commissioners James Danly, Mark Christie, Willie Philips and Allison Clements, who wrote a concurrence. Only Chair Richard Glick did not participate in the order; FERC's Division of Media Relations could not supply a reason for his nonparticipation.

The order also requires two compliance filings from PJM. The first, due within 30 days, calls for new tariff language codifying that only new service requests with no network upgrade costs and that do not require further studies can receive acceleration to a final interconnection-related agreement.

The second filing is due 60 days before PJM begins to study interconnection requests under its new rules, after the completion of the transitional studies.

PJM Vice President of Planning Kenneth Seiler | *© RTO Insider LLC*

PJM is also required to submit informational reports alongside its *Order 845* filings during the transitional period, detailing its progress toward reducing the backlog. The reports are to include the number of studies completed, average completion time, the number remaining in each cycle queue and updated timelines on when the RTO expects to begin and complete each phase.

Approval Paves Way for New Rules and Transitional Process

PJM has argued that the queue changes were needed as the number of new service requests tripled from 2019 through 2022, with more than 2,700 active projects as of May 10. In a *letter* accompanying filing, the RTO said the current interconnection process doesn't provide incentives for speculative projects to leave the queue in timely fashion. When such projects exit the queue late in the process, they trigger restudies impacting the cost allocation for other submissions further down the queue.

Shifting from a process of studying and allocating costs for each project individually, the new approach groups projects into clusters and conducts studies in three phases, with an increasing share of a readiness deposit required at each step equal to a portion of the network upgrade costs.

Deposits vary with the size of a project, ranging between $75,000 and $400,000. There will be "off-ramps" — or decision points — between each phase for developers who wish to discontinue their projects and partial refunds of the deposits.

Developers also are required to show evidence of site control, with escalating degrees required the further a project has progressed through the three phases. Currently, developers are only required to demonstrate site control once when submitting a project and only for the generator site.

For two queue cycles, projects that entered the queue between April 2018 and September 2021 will be studied under transitional rules, while projects valued under $5 million will be subject to a "fast track" process. PJM will begin to conduct studies under the new rules after completion of both the transitional cycles and the fast-track process.

Many protestors raised concerns about the potential for the fast track to allow less mature — and possibly speculative — projects to jump the queue over more mature, higher-cost

PJM News

projects. Protestors also complained that the $5 million threshold was arbitrary and that the readiness deposits are insufficient to weed out speculative submissions. (See *Renewable Devs Criticize PJM Response to FERC on Queue Proposal*.)

But FERC found that the interconnection rule changes strike a balance of allowing PJM to expedite its ballooning interconnection backlog, helping developers progress their projects toward construction, and letting mature projects continue under the current rules.

"PJM's proposed transition mechanism is a reasonable means of implementing PJM's queue reform proposal and reasonably balances the interests of completing the interconnection study processes for mature New Service Requests under PJM's current rules with the need to move expeditiously to a first-ready, first-served clustered cycle approach in order to clear the significant backlog and begin full implementation of the New Rules," the commission wrote in its order.

"We recognize that PJM's proposed queue cycle cutoffs for use of the current rules and the Transition Period Rules will inevitably exclude certain interconnection customers, but, as the commission has pointed out in multiple queue reform proceedings, 'any cutoff date inevitably will have that effect.'"

Operational Penalties Eliminated for Late Tx Service Request Studies

The approved proposal also removes tariff language outlining penalties for transmission studies that are not completed on time, which PJM argued is now unnecessary given that FERC Order 845 requires that failures to meet study deadlines be publicly reported to the commission.

Protestors contended that removing the language would contradict the commission's interconnection notice of proposed rulemaking and said the provision would lengthen delays for firm transmission service customers. But FERC determined that removal of the tariff language meets the requirements of Order 890, as the penalties "would not necessarily target delays due to studying firm transmission service requests."

Clements Concurs Reluctantly

Clements issued a concurring opinion in which she expressed reluctant support for approving PJM's proposal, which she described as an imperfect solution to an interconnection queue that has "spiraled out of control."

Clements was most concerned about the requirement that developers demonstrate 100% site control for interconnection facilities at the decision point at the end of the third study phase. She noted that commenters' protests raised the possibility that viable projects could be removed from the interconnection queue, particularly should a generation-owning transmission owner direct a late-stage route change to force a project out of the queue.

"They argue that the site control requirement may prove to be too onerous in practice because gen-tie line sites may involve numerous small land parcels for which minor issues could come up, and because last minute changes in line routes may occur. PJM's untested approach appears to be unique among RTOs," she said.

Clements' also expressed concerns about the elimination of penalties for transmission service request studies that do not meet their deadlines, a revision she said only complies with the commission's Order 890 due to the "unique circumstances of PJM's interconnection process."

To create an interconnection process that meets the needs of customers, she said the approved proposal should be viewed as "one step upon which several others could conceivably be layered." She encouraged PJM and other RTOs to consider implementing forward-looking study processes that would provide those applying for interconnection with a more information that is less prone to unpredictable changes based on changes to the queue.

"Further changes that hold potential to accelerate PJM's interconnection queue include modifying the threshold at which network upgrades are triggered by the interconnection process, and adjustments to cost allocation for interconnection upgrades such that network upgrade costs are less likely to spur queue withdrawal," she wrote. ■

PJM News

FERC Approves PJM Tariff Revisions for SAA Cost Allocation

By Devin Leith-Yessian

| Shutterstock

FERC on Friday approved revisions to PJM's tariff that assign the full costs of constructing transmission upgrades necessary for the installation of 7,500 MW of offshore wind in New Jersey to the state (*ER22-2690*).

The commission affirmed that the proposal conforms with Order 1000's State Agreement Approach, which permits a state to take on the cost of transmission upgrades for generation projects supporting their public policies. The order allows the installation of an estimated $1.07 billion in grid upgrades to go forward.

FERC found that the tariff revisions would not result in costs being passed to customers outside New Jersey, a concern raised by Long Island Power Authority; New York Power Authority; and three merchant transmission facilities (MTFs), Neptune Regional Transmission System, Linden VFT and Hudson Transmission Partners, which filed a protest as the "MTF Parties" on Oct. 31. (See *NY Stakeholders Balk at NJ OSW Cost Allocation*.)

The groups argued that the proposed language left open the possibility that a portion of the costs could be indirectly passed on to New York customers through border rate service. They called for more explicit clarifications to be added to preclude that possibility and specify that costs can only be applied to firm point-to-point transmission service.

The commission ruled that PJM adequately addressed those concerns in the revisions, as well as in a settlement agreement that FERC approved the same day between the RTO, its TOs and the MTF Parties, pertaining to point-to-point border rates (*ER19-2105*).

"We do not agree with MTF Parties that the crediting under the border rate revenue requirement, as proposed in the border rate settlement, may still result in New Jersey SAA project costs being passed through to entities that did not voluntarily agree to pay for those costs," the commission said. "The border rate settlement specifically provides that the revenue requirement will not include the costs of state agreement public policy projects. Passing on such costs would violate that term."

The order was unanimously approved, though Chair Richard Glick did not participate. Commissioner James Danly wrote in a concurring statement that he believes the order addresses the MTF Parties' concerns, but if they continue to believe there are issues with the approved revisions, they should seek a rehearing.

"To the extent to which the MTF Parties find that the language set forth in today's order fails to allay their concerns, they should pursue rehearing by citing the specific tariff language to which they object and should enumerate the specific misinterpretations that they fear, along with the consequences of those misinterpretations," he wrote.

The FERC approval now allows for PJM and the New Jersey Board of Public Utilities to shift their attention to filing amendments to the SAA. During a Nov. 4 meeting of the PJM Transmission Expansion Advisory Committee, Assistant General Counsel Pauline Foley said filing those amendments with FERC first required the approval of a cost allocation methodology from the commission. ■

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PJM News

NJ Shoots for 4 GW+ in 3rd OSW Solicitation

New Schedule Envisions 7 Solicitations by 2030

By Hugh R. Morley

New Jersey is seeking projects totaling 1.2 to 4 GW — and potentially larger — in the state's third offshore wind project solicitation planned for early 2023, according to a draft document released by the New Jersey Board of Public Utilities (BPU) on Thursday.

The *Solicitation Guidance Document* seeks proposals that are significantly larger than in the first two solicitations, which awarded projects totaling 1.1 GW and 2.658 GW, and expands the state's already aggressive effort to become a key player in the growing offshore wind sector. The document presents a new solicitation schedule shaped to accommodate Gov. Phil Murphy's decision in September to *increase* the state's OSW target capacity from 7.5 GW by 2035 to 11 GW by 2040.

"The board seeks to promote robust competition in this third solicitation and future solicitations to support the continued development of the offshore wind industry in New Jersey," the draft says.

The new schedule envisions four more solicitations after the third one next year, with each additional solicitation expected to award capacity of about 1.2 GW, though the BPU "may award projects above or below the target."

The first project is expected to come online in the 2024-2025 period, with the final project up and running by 2038. The draft says that for the 2023 solicitation, the BPU "reserves the right to select less than 1,200 MW or more than 4,000 MW of qualified projects if circumstances warrant."

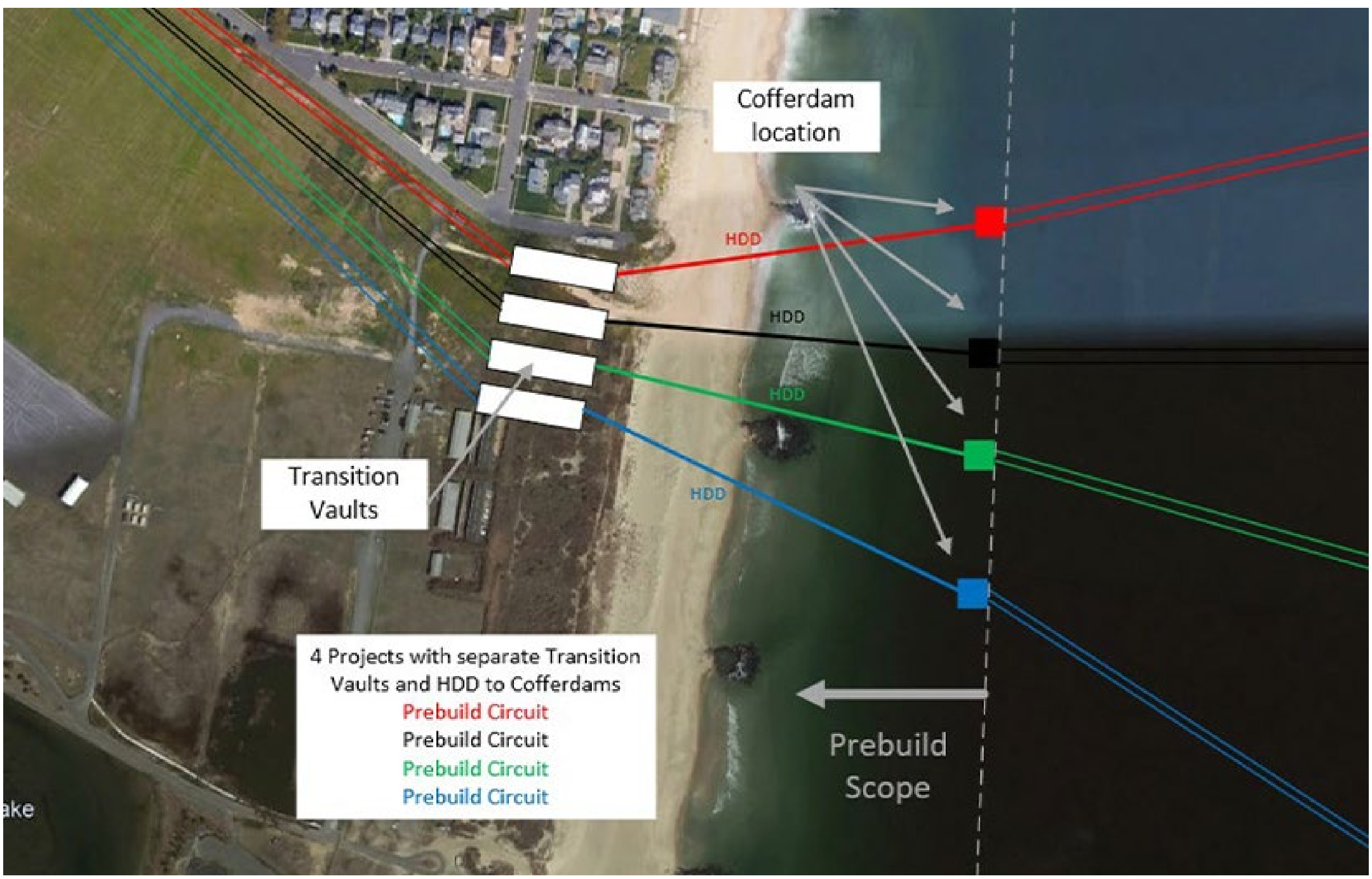
The BPU will seek stakeholder input on the draft solicitation at a *public hearing* on Dec. 13.

Building an Industry

The requirements set out in the draft solicitation for project applicants show that New Jersey is looking to build upon the state's OSW infrastructure already in development.

New Jersey awarded its first offshore wind project, the 1.1-GW Ocean Wind 1 developed by Denmark-based Ørsted, in 2019, and in 2021 awarded two more: the 1.148-GW Ocean Wind 2, and the 1.51-GW Atlantic Shores project, developed by a joint venture between EDF Renewables North America and Shell New Energies US. (See *NJ Awards Two Offshore Wind Projects*.)

The state has accompanied the project awards with an effort to position itself to serve other



The BPU's solicitation requires applicants to outline an offshore "prebuild infrastructure" that would hook into the recently approved onshore infrastructure. Applicants would have to provide plans to build duct banks and access cable vaults that would allow cables to run through them to the onshore connection points. | *NJ BPU*

PJM News

parts of the East Coast offshore wind sector by developing a logistics, marshalling and manufacturing hub. The heart of the effort is the development of what New Jersey officials say is the first custom-built wind port in the nation, committing $478.2 million to the project with bonding for another $160 million underway.

The wind port, located at Alloways Creek in Salem County, will include a 30-acre marshalling area for component assembly and staging; a dedicated, overland, heavy-haul transportation corridor; and a heavy-lift wharf with a dedicated delivery berth and an installation berth that can accommodate jack-up vessels. (See *NJ Wind Port Draws Heavy Hitters*.)

The BPU on Oct. 26 approved the expenditure of $1.07 billion for transmission upgrades to deliver 6,400 MW of OSW generation to the grid. The BPU picked the projects — the largest of which is an onshore substation known as Larrabee Tri-Collector Solution — from among 80 proposals submitted by 13 developers in response to a solicitation issued by PJM under FERC Order 1000's State Agreement Approach. (See related story, *FERC Approves PJM Tariff Revisions for SAA Cost Allocation*.) However, the BPU largely awarded contracts for onshore work and left the offshore infrastructure mostly unallocated.

The draft solicitation seeks to fill that gap by requiring applicants to outline a "prebuild infrastructure" that would interconnect with the recently approved onshore infrastructure. Applicants would have to provide plans to build duct banks and access cable vaults for transmission to run to onshore interconnection points.

"Developers of future qualified projects would then install their cables through the prebuilt duct banks utilizing the prebuilt cable vaults, with minimal further disruption to the communities" around the interconnection points, the solicitation says.

Economic Impact

The solicitation also seeks to generate a range of project alternatives, requiring applicants to submit at least one 1.2-GW project while adding that they are "highly encouraged to submit applications covering a range of project sizes up to approximately 4,000 MW."

Applicants would have to submit a package with a completed application form and an explanation of their project, as well as an in-depth analysis of its economic impact on the state. They would have to detail the "proposed investment in New Jersey offshore wind infrastructure, supply chain, labor force development" and other investments. They would also have to outline the economic development impact on communities in the state and provide detailed job creation information, including location, types and number of jobs it would generate, and wage or salary levels.

The proposal must also say whether the planned project will use the New Jersey Wind Port or "alternative infrastructure" located in the state or elsewhere.

"The BPU encourages use of the New Jersey Wind Port for project marshalling and for locating Tier 1 manufacturing facilities, where feasible," the solicitation says.

The heart of the application, however, is the cost of the project and its underlying economics. Applicants must set out the level of the OSW renewable energy certificate (OREC) at which the developer believes the project would be commercially viable.

"OREC pricing will be on a pay-for-performance basis," the solicitation said. "Payments will be made on a dollar-per-megawatt-hour basis."

The OREC must reflect the total capital and operating costs for the project over 20 years, "including costs of equipment, construction, financing, operations and maintenance, and taxes," offset by any state or federal grants or subsidies, according to the draft solicitation. "The OREC pricing proposal shall specify the nameplate capacity, expected energy output and assumed capacity factor for the proposed project, along with the number of ORECs that the project will produce." ■

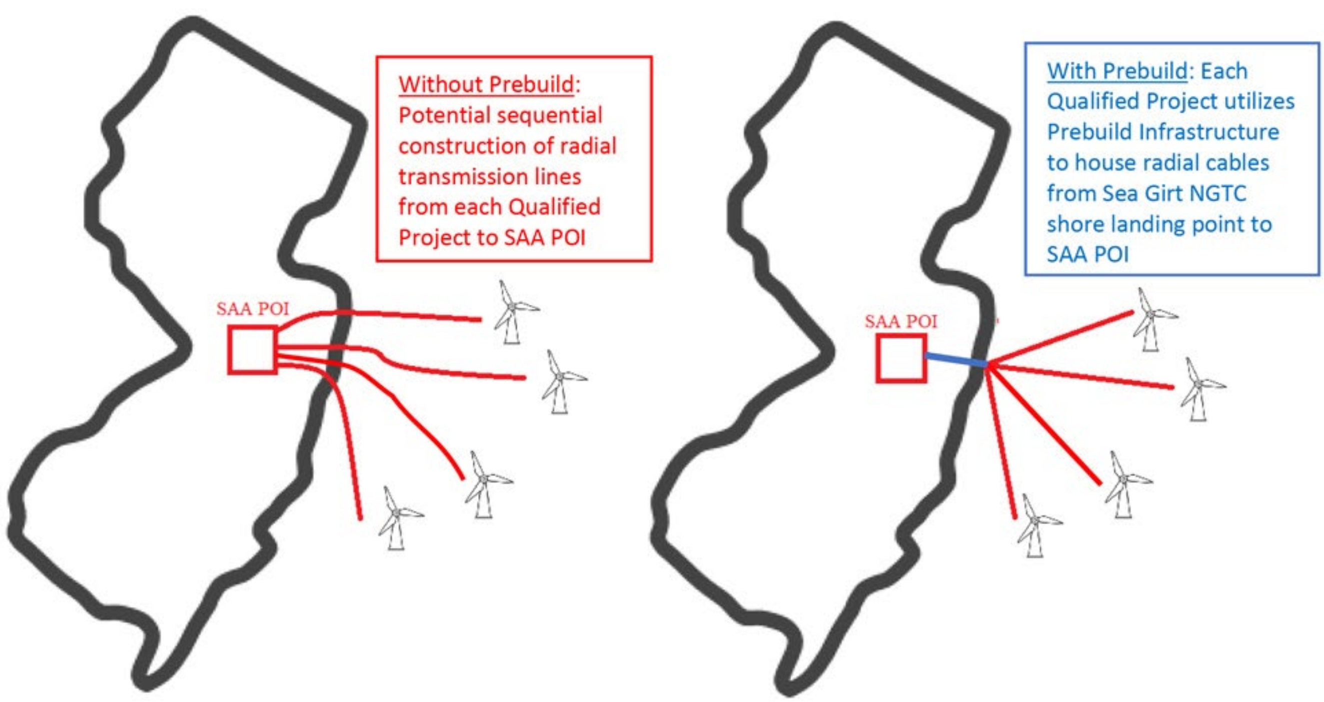


Diagram of qualified project connections to point of interconnection (POI) with and without prebuild | *NJ BPU*

SPP News

SPP Issues Final Markets+ Proposal

RTO, Potential Members to Begin Market Design in April

By Tom Kleckner

SPP on Wednesday released a *final proposal* detailing the proposed governance structure, basic market design and other key features for the RTO's day-ahead market offering in the Western Interconnection.

The RTO will now spend the next few months engaging with parties that have already expressed interest in committing to Markets+, a conceptual bundle of services that centralizes day-ahead and real-time unit commitment and dispatch. SPP says the market and its "hurdle-free transmission service" will help integrate the region's rapidly growing fleet of renewable generation.

SPP has held several in-person meetings and webinars over the past year to gather input and reach agreement with potential stakeholders on the service offering. CEO Barbara Sugg said in a *press release* that collaborating with Western stakeholders on the Markets+ design has been a "tremendous effort." (See *Governance, Resource Adequacy Key to SPP's Markets+*.)

"Thanks to the dedication and engagement of these entities over the past year, I'm confident we can design and deliver a market that addresses challenges unique to the region and provides value to western customers," she said.

The service offering anticipates a two-phase process for continued development of Markets+. Potential participants and stakeholders will financially commit to design the market protocols, tariff and governing documents in the first phase. A second phase begins after FERC's approval of the tariff; SPP will acquire the necessary software and hardware while participating entities fully commit to fund and are integrated into the system.

Parties interested in committing to financing further development of the market must sign a funding agreement by April 1 that will cover SPP staff's involvement.

Load and/or generation entities that sign the agreement would get a vote on the Markets+ Executive Committee (MPEC) in the first phase, and their representatives would be eligible for appointment to working groups and task forces. Those without load or generation would sign a participation agreement and make a one-time $5,000 payment or obtain a waiver in order to vote on tariff and protocol recommendations.

The MPEC is akin to SPP's Markets and Operations Policy Committee in the Eastern Interconnection. It will provide a forum for market participants, stakeholders and non-voting stakeholders to discuss issues and to review system or process-improvement proposals recommended by SPP, the Markets+ State Committee and members and stakeholders.

The committee will report to the Markets+ Independent Panel (MIP), the highest level of authority for decisions related to the market, but with the SPP Board of Directors providing independent oversight. SPP said the board will "give significant recognition and deference to the [MIP's] decision-making role."

Because the RTO does not expect the MIP to be established during phase one, a three-person subcommittee of the SPP board will perform the decision-making functions until the MIP can be formed. ■

The Markets+ governance structure | *SPP*

Company Briefs

IPA Rejects Bids to Buy Out Assets, Keep Utah Coal Units Open Past 2025

The Intermountain Power Agency Board of Directors last week voted to reject unsolicited bids from two companies to keep the area's two coal-fired units open past their scheduled closure in 2025.

IPA was approached by Enchant Energy and Fibernet in September with the idea of extending the life of the coal burning portions of the plants by using carbon capture and sequestration technology. The companies also proposed using electricity generated by the older units to operate high density data centers. As part of the proposal, at least one of the companies also sought to become a member of the IPA, which is comprised of 23 Utah municipalities. However, the companies returned to IPA in October with a revised proposal that included buying out all of IPA and its assets, and leasing back the assets for IPA to operate.

IPA's resolution rejecting the proposal states the proposals "were not in response to any formal or informal solicitation by IPA, but rather were submitted by (the companies) on its own initiative."

More: *Millard County Chronicle Progress*

Honda to Build Hydrogen-Powered CR-V in US in 2024

Honda last week announced it will build a hydrogen fuel-cell version of the CR-V crossover in Ohio in 2024.

Honda said the vehicle will serve as a replacement for the Clarity Fuel Cell, a hydrogen-powered sedan offered in California from 2017 to 2020. This fuel-cell unit, which essentially turns liquid hydrogen into electricity to power the electric motor, is said to improve upon the old Clarity's powertrain and also uses 80% less platinum.

The fuel-cell CR-V will join the Toyota Mirai and Hyundai Nexo as the only hydrogen vehicles sold in the U.S.

More: *Car and Driver*

Lordstown Shipping First Batch of Electric Trucks

Lordstown Motors last week received approval to ship the first batch of its first model, the Endurance pickup.

The company said the first units of the initial batch of 500 trucks were being shipped after passing safety tests and hitting several key benchmarks. It did not state how many of the pickups have been made.

More: *The Associated Press*

Canoo Sends EV Pickup Truck to US Army for Testing

Canoo last week delivered its first Light Tactical Vehicle to the U.S. Army for a demonstration project aimed at showing how its modular electric platform can support mission-specific configurations for less money.

Canoo said the 600-hp, purpose-built vehicle is designed to be durable in extreme environments, with a focus on passenger and battery safety.

The Army, which aims to incorporate scalable vehicles into its operations, awarded the company a contract in July to supply a vehicle for analysis and demonstration.

More: *TechCrunch*

ACE Trains Going 100% Renewable Diesel

The Altamont Corridor Express last week announced its trains will run on 100% renewable diesel fuel, making it the first commuter rail service in Northern California to make the switch.

The San Joaquin Regional Rail Commission (SJRRC), the agency that operates the ACE train system, anticipates the fuel switch will reduce ACE greenhouse gas emissions by 99%. The announcement is a step toward the goal of net-zero emissions operations, set under the commission's Climate Action Plan.

SJRRC said the renewable fuel source comes from "responsible and sustainable feedstock, such as used cooking oil and/or inedible corn oil." ACE uses up to 51,000 gallons per month.

More: *Pleasanton Weekly*

Federal Briefs

DOE Launches Program for Upgrades in Public Schools

The Department of Energy last week announced that applications are open for the Renew America's Schools grant program. The initial funding round, up to $80 million of the $500 million program, is available to public schools to perform energy improvements in the highest-need K-12 districts.

The program will support infrastructure improvements in schools, with a focus on local education agencies that qualify as rural and/or high poverty. Eligible projects can include new heating and ventilation and air conditioning.

The deadline for applicant concept papers is Jan. 26, and full applications are due April 21.

More: *Energy.gov*

Senate Panel Votes in Favor of Geer for TVA Board

The U.S. Senate Environment and Public Works Committee last week voted 11-9 to endorse President Biden's nomination of Beth Prichard Geer for one of the open seats on the governing board for the Tennessee Valley Authority. Geer is the former chief of staff to Vice President Al Gore Jr.

Geer's nomination will head to the Senate along with five other Biden nominees. The full Senate must confirm the board appointments in the next month to avoid having the nine-member board reduced to just three members and unable to have the quorum required to conduct business or adopt policies.

All five current board members were appointed by President Donald Trump, but the terms of A.D. Frazier and Jeff Smith will end Dec. 31.

More: *Chattanooga Times Free Press*

Park Service Approves Dominion's Pipeline in NC

The National Park Service last week approved an application by Dominion Energy to put a natural gas pipeline under the Blue Ridge Parkway in North Carolina.

Even during construction, the pipeline will not have a "significant impact" on the parkway or the Mountains-to-Sea Trail, which also runs over the proposed pipeline location, according to a findings report.

The Blue Ridge Parkway stretches 469 miles from Shenandoah National Park in Virginia to Great Smoky Mountains National Park in Cherokee, North Carolina. It is the most visited unit of the National Park Service, with 16 million visitors in 2021.

More: *Asheville Citizen Times*

Treasury Outlines Wage, Apprenticeship Reqs for Clean Energy Tax Credits

The Treasury Department last week released guidelines detailing new wage and apprenticeship standards firms must meet to qualify for tax incentives under the Inflation Reduction Act.

Firms must pay workers the prevailing wage for their area and abide by rules for the use of apprenticeship programs. The prevailing wage is determined by the Department of Labor and posted on its sam.gov website.

The standards go into effect Jan. 29.

More: *CNBC*

Report: TVA's Allen Fossil Plant Ranks No. 10 in Most Contaminated US Sites

The Tennessee Valley Authority's coal ash dumps at Memphis' now-defunct Allen Fossil Plant rank as the 10th worst contaminated sites in the country, according to a report from the Environmental Integrity Project and Earthjustice.

TVA's own monitoring data shows its Memphis dumps are leaking arsenic at levels nearly 300 times safe drinking water limits. The report also shows that coal ash dumps at every TVA coal-fired facility across Tennessee are leaking dangerous contaminants — including arsenic, cobalt, lithium, molybdenum, boron, lead and sulfate — at unsafe levels, into groundwater.

In 2015, TVA was ordered to investigate the extent of contamination caused by its coal ash dumps, come up with a plan to clean up its pollution and decide what to do with the dumps to prevent future contamination. The utility has yet to complete its investigations at its Tennessee plants or announce plans for the millions of tons of coal ash.

More: *Tennessee Lookout*

State Briefs

CALIFORNIA

Sunrise Power Gets OK to Increase Generation of Gas Plant

Sunrise Power, owner of the 22-year-old Sunrise Power Project, last week won approval from the San Joaquin Valley Air Pollution Control District to proceed with changes that will allow the plant to produce 635 MW — 50 MW more than its current capacity.

Staff concluded that the proposed changes would increase emissions of sulfur oxides, nitrogen oxides and other pollutants but "would not result in any significant adverse direct, indirect or cumulative impacts to the environment" if Sunrise Power makes a series of minor changes required by the air district. The plant is expected to operate only at times when the state grid is in immediate risk of running out of capacity.

The Energy Commission is scheduled to vote on the matter Dec. 14.

More: *Bakersfield.com*

MICHIGAN

BWL Retires Last Coal-fired Plant

The Lansing Board of Water & Light retired its last coal-fired power plant, the Erickson Power Station, on Nov. 27.

BWL, which has a goal of becoming carbon-neutral by 2040, is now the state's largest utility to generate coal-free power.

More: *WKAR*

NORTH DAKOTA

PSC Approves Wind Farm in Logan, McIntosh Counties

The Public Service Commission last week voted 2-1 to approve the proposed $390 million Badger Wind project.

Orsted Onshore North America plans to complete the 250-MW project, which will consist of 74 turbines, by October 2023.

More: *The Bismarck Tribune*

PSC to Appoint Judge to Commission for CO2 Pipeline Decisions

The Public Service Commission last week said it plans to appoint a temporary member for decisions regarding the proposed Summit Carbon Solutions carbon dioxide pipeline after the panel's chair recused herself to avoid perceived conflicts of interest.

The PSC and staff discussed appointing Administrative Law Judge Tim Dawson to be a decision-maker in the case, temporarily replacing Chair Julie Fedorchak. The panel also discussed choosing Bismarck attorney Zachary Pelham to serve as advisory council for any Summit decisions. The commission had hired Pelham previously to help with legal counsel on siting cases.

The proposed pipeline would gather carbon dioxide emissions from ethanol plants in several Midwestern states and transport them to North Dakota for permanent underground storage.

More: *The Bismarck Tribune*

OKLAHOMA

Corp. Comm. Approves Oklahoma Natural Gas Rate Hike

The Corporation Commission last week approved a $19.6 million rate hike for Oklahoma Natural Gas.

The average residential customer will see a monthly increase of $1.15, while low-income customers will see an increase of $0.27 following the calculation of the Excess Deferred Income Taxes credit.

The company said the increase is needed to recover costs from investments.

More: *KOKH*

SOUTH DAKOTA

Xcel Energy Seeks Rate Hike

Xcel Energy has asked the Public Utilities Commission for a $44.1 million (17.9%) rate hike beginning next year.

The increase would raise the average residential customer's bill by $19.58 per month.

Xcel cited costs related to decommissioning nuclear plants, upgrading technology, and keeping up with cost pressures as reasons for the increase.

More: *The Center Square*

TEXAS

Entergy Issues RFP for 2,000 MW of Renewable Resources

Entergy Texas recently issued a request for proposals for 2,000 MW of solar and wind generation resources.

Between 2019 and just prior to this latest RFP, Entergy Texas had issued two RFPs totaling 600 MW.

More: *Entergy*

Mountain Creek Gas Unit to End Year-round Operations

TexGen Power has alerted ERCOT that its largest gas-fired unit at its Mountain Creek Power facility will become a seasonal unit on March 1.

TexGen filed with the ISO a notification of suspension of operations on Nov. 30. The unit, which has a summer seasonal net max sustainable rating of 568 MW, had been operating year-round. As a seasonal unit, it will operate from March 1 through Sept. 30. The unit, one of three Mountain Creek units still operating, began commercial operations in 1967.

The plant was one of four acquired by TexGen after Exelon declared Chapter 11 bankruptcy in 2017.

More: *Global Energy Monitor*

VIRGINIA

AG Seeks Freeze on Loan Payments for Pink Energy Projects

Attorney General Jason Miyares joined a coalition of eight other states in asking five solar lending companies to freeze loan payments and interest accruals for customers who had solar installed by Pink Energy but haven't received a working system. Pink Energy, which also does business as Power Home Solar, filed for bankruptcy in October.

Miyares' letter asks the companies, which include Dividend Solar Finance, GoodLeap, Cross Riverbank, Sunlight Financial, and Solar Mosaic, to suspend consumers' payment obligations "until an investigation into the individual consumers' complaints can be completed."

Miyares said his office launched an investigation into the company after receiving more than 100 complaints from residents about alleged deceptive business practices. However, before the investigation was complete, Pink Energy filed for bankruptcy.

More: *Virginia Mercury*

WISCONSIN

PSC Approves WEC Energy Group Rate Increase

The Public Service Commission last week approved a nearly $367 million revenue increase for subsidiaries of the WEC Energy Group, including We Energies and Wisconsin Public Service.

The utilities say the added costs are the result of investments in renewable energy and natural gas generation, a $370 million storage project approved last year, and improvements to the distribution grid, as well as inflation.

The increase is expected to add about $12 for the typical We Energies monthly bill and about $9 more for WPS customers, according to estimates.

More: *Wisconsin State Journal*

Northeast news from our other channels

Mass. Clean Heat Report Sidesteps Ban on New Gas Installations

NetZero Insider

New York State Clean Energy Jobs Hit Record High in 2021

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