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RTO Insider

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EPA Poised to Release Rule on Power Plant CO2 Limits

Rule Expected to Encourage Carbon Capture

By James Downing

EPA is reportedly poised to propose rules that would require all coal and gas-fired power plants to reduce or capture nearly all of their carbon dioxide emissions by 2040.

The New York Times *reported* Saturday that EPA plans to release a rule that for the first time would set limits on carbon dioxide emissions from existing power plants.

The pollution limits would not be technology specific, allowing natural gas plants to either capture their carbon, or switch to "green" hydrogen that is produced without carbon emissions, according a report in the *Times* that was largely *confirmed* by *The Washington Post*.

While carbon capture has proven expensive on power plants, recent federal legislation, including the Infrastructure Investment and Jobs Act and the Inflation Reduction Act, have set up a comprehensive framework that should enable the wide-scale deployment of carbon capture by 2030, the Carbon Capture Coalition said Monday in releasing its *2023 Federal Policy Blueprint*.

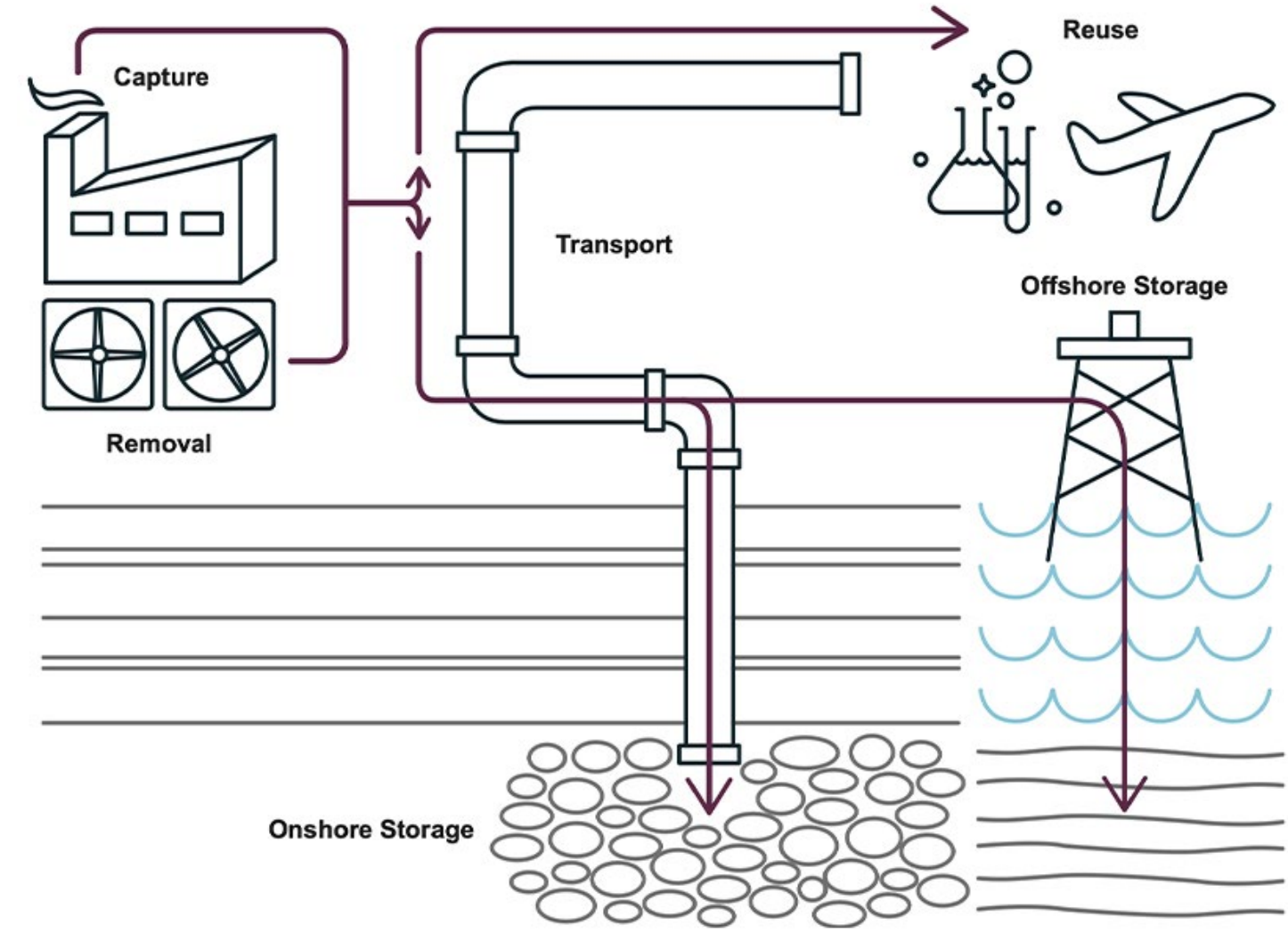
The IRA increased federal tax credits for electric utilities that capture their carbon dioxide from $30 to $50/ton of CO_2 to $85 to $135.

At a press event announcing the blueprint Monday, the coalition's Executive Director Jessie Stolark said its wide-ranging membership has not had a chance to coordinate a response to the reported regulations yet. The group has focused mainly on market-incentives to encourage carbon capture technology, she added.

"I really want to underscore that our members agree that deploying carbon capture technologies in the power sector is absolutely critical to reducing emissions, as well as providing a more affordable, reliable baseload power and a deeply decarbonized energy grid," Stolark said.

Shannon Heyck-Williams, vice president of climate and energy for the National Wildlife Fund, who participated in the coalition event, said her group welcomed news of EPA's plans.

"WF is very excited to see this rule come out," she said, saying CCS technology could have a role to play with some natural gas plants.



Carbon Capture Coalition image from its 2023 Federal Policy Blueprint showing the carbon management value chain | *Carbon Capture Coalition*

FERC/Federal News

"Obviously, we can't adequately tackle climate change unless we're really dramatically reducing power sector CO_2 emissions. And, frankly, we could get to zero. That's the goal."

In response to EPA's request last year for comments on how it should handle emissions from "electric generating units," the Edison Electric Institute *spelled out* a way that it said could encourage cuts without mandating specific technologies.

EEI noted that for now the main way to cut emissions from power plants is to make them more efficient, with both hydrogen and carbon capture technologies not quite ready for mass deployment.

"Both hydrogen co-firing and CCS technology face a number of other challenges that will need to be overcome to enable commercial scale use throughout the industry," EEI said. "Government and industry are investing in addressing these cost, technology, and infrastructure challenges. With that investment, there is reason to be optimistic that these challenges will be overcome in this decade."

EEI argued that any new rules should be flexible, saying that hydrogen and carbon capture might work in some regions of the country but be infeasible in others. The agency should allow new power plants to retrofit those technologies when they become viable.

EEI also suggested that the agency would benefit from shifting to mass-based tonnage requirements for regulated units. Previous emissions rules have used a rate-based system.

"Since decreases in (or limits of) a unit's capacity factor have a direct impact on its CO_2 emissions profile, states, EPA, and units can employ a mass-based approach to leverage the emissions reductions benefits of a decrease in capacity factors, while preserving maximum operational flexibility to support overall system reliability by preserving the availability of units for resource adequacy, particularly during extreme weather events or other emergency conditions," EEI said.

"We've got to go with a scale, we've got to go with the pace like never before," U.S. Deputy Secretary of Energy David Turk said at the coalition's webinar Monday. "My former colleagues at the [International Energy Agency] projected that by 2030, we'll need to lock away roughly 30 times as much carbon as we're currently managing, and nearly quintuple that by the middle of the century."

DOE has made $10 billion available for a suite of carbon management applications, including the recent request for six demonstration projects at coal and natural gas plants, he added. DOE is also working with the Treasury Department to finalize the expanded 45 Q tax credit for carbon capture, said Turk.

EPA's power plant rules would not be finalized until next year, following a public comment period. The Biden administration hopes to complete the regulations before Republicans could upend them by winning control of Congress in 2024. The Congressional Review Act allows a new Congress to reject regulations finalized within 60 days of the previous Congress.

The administration also is attempting to craft the rules to withstand certain court challenges.

The Supreme Court ruled last June that the Obama administration's EPA failed to provide "clear congressional authorization" for its Clean Power Plan, which would have compelled generation shifting to reduce carbon emissions from coal-fired power plants. (See *Supreme Court Rejects EPA Generation Shifting*.) ■

FERC/Federal News

Congress Doubling Down on Bipartisan Push for 'Permitting Reform'

U.S. Chamber Launches 'Permit America to Build' Lobbying Effort

By K Kaufmann

WASHINGTON — Democrats in Congress want legislation to streamline and speed up permitting for clean energy projects and transmission, while Republicans want it for mining and drilling on federal lands, and for pipelines for hydrogen and carbon capture projects as well as for oil and natural gas, according to Sen. Shelley Moore Capito (R-W.Va.), ranking member of the Senate Environment and Public Works (EPW) Committee.

And both sides know new laws will be vital for developing domestic supply chains for critical minerals, such as lithium, cobalt and nickel.

Somewhere between these "essential views," Capito said April 18 at a breakfast meeting at the U.S. Chamber of Commerce, is the possibility to "forge a compromise … to say to the Democrats on our committee and Republicans on our committee, we may be approaching this from a different angle on where our real needs are.

"Successful legislation is about not just getting but giving up the things that you really don't want, and so to get there we're going to have to have that mindset across the committee," she said.

"Permitting reform," as it is commonly referred to, has become a high priority for both parties in the 118th Congress and for the Chamber, which has launched its own lobbying campaign called "Permit America to Build." Last week's event was a kickoff for the campaign, timed to coincide with a fly-in lobbying effort by members of the American Clean Power Association.

The goal for a range of stakeholders is bipartisan legislation that will provide "meaningful" change and break through the congressional inertia that has long surrounded the issue, said Neil Bradley, chief policy officer at the Chamber.

"Unfortunately, this is one of those issues where failure doesn't immediately lead to catastrophic consequences," Bradley said. "When we push permitting reform, it's easy to keep talking about it; it's easy to keep insisting on one position — your side's position — while the other side insists on theirs. … Maybe we'll find a solution later; maybe we'll get a better outcome after the next election."

Sen. Shelley Moore Capito (R-W.Va.) | © *RTO Insider LLC*

Leonardo Moreno, president of AES Clean Energy, said the lack of consistency in permitting processes is a key challenge for his company's efforts to build new solar, wind and storage projects. "If you go to agencies in each of our regions in the U.S., the main agencies are the [Bureau of Land Management], the Army Corps of Engineers and Fish and Wildlife," Moreno said. "They don't apply [the National Environmental Protection Act] in the same way; each of them has their own way of applying the process."

Staff turnover can also mean further delays, leading to requests for new studies on different issues, he said.

But if the passage of the Infrastructure Investment and Jobs Act and the Inflation Reduction Act has not exactly created a sense of urgency, they have at least prompted some serious momentum around the long-dormant issue. The two laws are pouring billions of federal funds into a range of clean energy and other infrastructure projects, and the byzantine federal permitting process is now seen not only as a roadblock for clean energy and other infrastructure but as a national security issue that is integral to building out domestic supply chains.

Exhibit A is the 732-mile *TransWest Express* transmission line, which filed its first application for a right-of-way on federal land back in 2007 and only recently received final approval from the Bureau of Land Management to start construction. Completion is targeted for 2027, when the high-voltage line will send power from Wyoming wind farms to Southern California. (See *TransWest Express to Break Ground After BLM Approval*.)

Both EPW and the Senate Energy and Natural Resources (ENR) Committee have scheduled hearings on permitting reform this Wednesday and on May 11, respectively.

"These upcoming hearings are vital to understanding how we can achieve bipartisan consensus that makes it possible for America to build again and maintain our status as a global energy leader," Sen. Joe Manchin (D-W.Va.), chair of the ENR Committee, said in a statement. "Americans cannot wait any longer, and neither can I."

NEPA not Sacrosanct

While Senate Majority Leader Chuck Schumer (D-N.Y.) pronounced the House Republicans' energy bill *H.R. 1* "dead on arrival," both Capito

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Sen. Joe Manchin (D-W.Va.) | © RTO Insider LLC

and Manchin said its permitting provisions, which are almost exclusively focused on fossil fuels, could provide a starting point.

"Nothing should be dead on arrival," Manchin said at the Chamber event, arguing that looking at the opposition's proposed legislation allows for a process of improvement. "We're not going to have a perfect piece of legislation, [but] we can have a piece of much better legislation," he said.

Both Manchin and Capito introduced permitting bills after passage of the IRA. Capito's Simplify Timelines and Assure Regulatory Transparency (START) Act (*S. 4815*), stalled out in the EPW Committee, while Manchin made repeated efforts to get his Building American Security Act into other must-pass legislation, such as the National Defense Authorization Act. (See *Manchin Permitting Bill Falls Short in Senate*.)

Capito laid out what she sees as the core components of any compromise legislation.

First, she said, the bill should be "technology- and fuel-neutral to benefit energy projects of all kinds," as well as other infrastructure projects, including roads, water and broadband. Another key component would be "enforceable deadlines." When federal agencies don't meet deadlines, "what happens?" Capito said. "Basically nothing. … All it does is push more and more of the burden onto whoever the developer is, the builder is, the community is."

A 60-day deadline for filing judicial challenges to an approved project is another must-have, Capito said. "We're going to first ask for some substantive changes to the NEPA review, also to the Clean Water Act. … That may be too far of a stretch, but we're going to try."

But Rep. Scott Peters (D-Calif.), a former environmental lawyer, says NEPA is not sacrosanct. "That approach simply is not compatible with science [and] the time we have left to maintain a stable climate," he said.

Peters has made permitting legislation his personal mission and is working across the aisle with Rep. Bruce Westerman (R-Ark.) to find bipartisan solutions. For example, Peters said, "we can reduce the level of review for climate projects on non-sensitive land. … There's no reason a solar project on degraded land, miles away from people, should go through the same process as a community [solar] project in a local community."

Judicial review processes should be tweaked "to protect vulnerable communities while preventing wealthy NIMBYs and bad actors from blocking central clean energy projects … and ensure the federal government has the authority to build a reliable, environmental grid," Peters said.

"If 52 years after NEPA, we're still complaining about the effect of pollution on underserved communities … it's time to expand our conversation," he said. "When there's so much money out there to do clean energy, and whether you're a climate activist or just a taxpayer, you don't want to see that money wasted on process."

Good Things Fast

The Chamber's goal is to get a "durable, meaningful" permitting bill passed by the end of the summer, and it aims to keep up the pressure with its lobbying campaign, according to an organization spokesperson.

"In the coming weeks and months, we will hold additional events activating our vast state and local Chamber network," the spokesperson said. "There will be many conversations both inside and outside the Beltway, and … we will work closely with members of the House and Senate on legislative language consistent with our principles."

Similar to Capito's core components, the Chamber is calling for permitting that provides predictability and transparency for businesses, better coordination between federal agencies and broad stakeholder input.

But Jason Grumet, CEO of the American Clean Power Association, believes a more basic shift in mindset is going to be needed. Focusing on national security, economic development and government efficiency have, to date, not gotten the job done on permitting because "there was a perception that this was trying to advance an energy system that was not consistent with environmental imperatives," he said.

The inefficiency of permitting has been "weaponized" and used to slow down or prevent "high-target infrastructure," Grumet said.

"There is absolutely no political coalition that can move forward legislation that is simply focused on fossil [fuels]," he said. "There is equally absolutely no possibility of moving legislation through a closely divided Congress that is only focused on clean energy. …

"There's not a single piece of legislation that can pass this Congress that will be the end of the discussion," Grumet said. "But it is the beginning of shifting our national consciousness to recognize that making good things happen fast is the future of the country."

Capito would also like to see a bipartisan permitting bill passed before Congress adjourns for its August recess. While some House Republicans have suggested attaching H.R. 1 to any deal on raising the national debt limit, Capito said the priority should be getting the bill right.

"Get the policy right," she said. "And then we'll find the vehicle." ■

Christopher Guith (left), U.S. Chamber of Commerce, talks permitting with Rep. Scott Peters (D-Calif.) | © RTO Insider LLC

FERC/Federal News

Has Dynamic Pricing's Time Come?

PRD is Rare, but Many Say it will Help the Grid Transition

By James Downing

Price-responsive demand has long been supported by economists, but despite the significant investment in advanced meters, it has yet to take off outside a few jurisdictions.

The Energy Systems Integration Group (ESIG) is releasing a series of *papers* this year, which Associate Director Debra Lew said are intended to raise awareness in the industry of how important it is to make the demand side a more active player going forward.

"We're going to need that flexibility for high levels of renewables and high levels of electrification in the future," Lew said in an interview.

In EPA's recent rule, which it expects to greatly increase the number of electric vehicles purchased, it specifically pointed to time-varying rates as a way to charge all those cars without overloading the grid. (See *EPA Releases Emissions Rules Aimed at Boosting EVs*.)

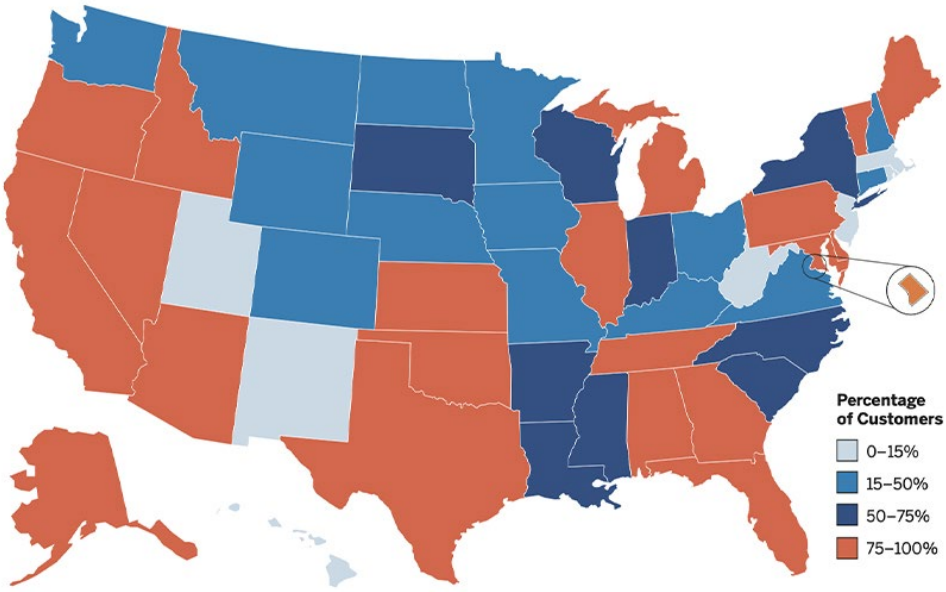
Plenty of attention has been paid to programs such as demand response, or the aggregation of distributed energy resources under FERC Order 2222, but less focus has been paid to reducing demand through some kind of time-varying rate.

"Every time I bring up pricing, I always get told, 'We don't want to touch that with a 10-foot pole,'" Lew said. "So, I think it's a really important, critical piece of the problem, and we're hoping to shine a light on it, and to get industry to pay more attention to this, because it is a critical way of getting demand to provide that flexibility."

Pricing should be part of the industry's holistic planning process, where they can help avoid major spending on new resources, she said.

"If you're thinking about adding storage to your system, maybe you should do time-of-use rates instead," Lew said. "Think about some of these rates as replacements for resources that you might add to your system. If you're thinking about adding a gas peaker, maybe instead you should do a peak-time rebate or critical-peak pricing."

The idea of making the demand side more active is far from new, with the first DR programs going back decades and advanced metering infrastructure being rolled out to most customers in the country over the last decade-plus.



A graphic showing smart meter deployment by state from ESIG | *ESIG*

"As of 2021, I think there are approximately 115 million installed smart meters, and this is representing roughly 80% of all U.S. residential customers," Brattle Group Principal Sanem Sergici said in an interview. "But when you go to [the U.S. Energy Information Administration] and look at their most recent data, only about 6% of the residential customers are on some sort of a time-varying rate."

Time-varying pricing has not followed the rollout of smart meters because of inertia around how electricity has already been priced and some fear of the unknown, said Sergici, who contributed to ESIG's reports and has tracked the issue for *Brattle* for years.

"Although, if you ask me, it's not unknown anymore," she added. "I mean, we have so much data. We have so much experience under our belts at this time when it comes to understanding customers response to these dynamic prices."

Many industry veterans have bad memories about the first wave of DR programs 30 years ago that did not work as well as expected, but Lew noted much has changed since then. The industry has access to more advanced communications and control technology; the changing dynamics of the grid make the need more acute; and sophisticated customers such as data centers have shown that they can be very flexible if they get the right signals from the grid.

"I don't think this is rocket science," Lew said. "I think that it's kind of ridiculous that it's taken us this long to take this seriously."

What to Charge?

Economists generally favor raising prices when demand is higher and having them lower when it is not, but former FERC Chair Jon Wellinghoff, who is now the chief regulatory officer at the aggregation firm Voltus, said that that

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would never fly politically. Dynamic pricing means customers must pay more when they use power the most, such as running their air conditioners on the hottest days of the year.

"That's a penalty for consumers," Wellinghoff said. "What they should be doing instead is rewarding consumers for not using energy during that time and paying them to not do that. And if they, in fact, gave them a reward, instead of a penalty, it would flip the whole thing on its head; it would make it much more palatable and much more acceptable for consumers."

Voltus is working with Ameren Illinois to pay some of its mass-market customers who have smart thermostats to reduce usage during peak demand times. Wellinghoff argued that is much more attractive to customers than any kind of time-varying prices.

Price-responsive demand programs were sold as the key to advanced meters' consumer benefits, but despite the meters being rolled out to most consumers, such programs have not been to nearly the same extent.

"I think it was oversold as to actually what it would be able to do and how it would be able to help consumers," Wellinghoff said of advanced metering.

The meters rolled out to most residential customers are only collecting prices every five minutes, which makes them inadequate to really help with the sophisticated load management programs that Wellinghoff supports, he said.

FERC Order 2222, which requires RTOs to accept aggregations of distributed energy resources, is one way that the industry will be able to get the demand side into the market, but that transition needs to happen faster, said Wellinghoff. Getting Order 2222 fully implemented and demand more into the markets is going to require some changes from the distribution utilities.

"I think they're sort of feeling afraid of being left out. And they're not sure what their role should be. And they don't want to accede their role to simply being a wires company. They want to do other things. But they're not good at doing those other things, because they have never had experience in the competitive arena."

Having the utilities focus on expanding the distribution system, while an independent distribution system operator (DSO) handles balancing various resources with flexible demand would lead to the kind of grid Wellinghoff sees in the future.

Utility Perspective

The concept of a DSO is just an idea at this point, so balancing all the activity on the distribution system is still firmly in utilities' control. That has made implementing Order 2222 tricky, Portland General Electric Senior Vice President of Advanced Energy Delivery Larry Bekkedahl said in an interview.

"I don't think that folks really thought through the full extent of the impacts on the distribution system, when we have traditionally been really good in the transmission generation space and bidding and markets in that space," Bekkedahl said. "But to go to the distribution, you've got to be able to communicate with those that are operating the distribution system in the same way you do with the generators and transmission folks. We have not been set up for that."

Without significant additional work bringing the utilities that run the distribution system into that picture, it will never be fully optimized, and it just has to deal with whatever extremes are placed on it, he said.

While Bekkedahl has some doubts about opening everything to third parties, virtual power plants and increased demand flexibility are a key part of the Oregon utility's plans to keep the grid balanced. Going forward, Bekkedahl expects about a quarter of all supplies will come from distributed resources and that growing percentages of the rest will be from intermittent renewables.

"If we're going to get to our decarbonization targets … we absolutely need as much flexibility in the load as possible because we've added all this variability in the generation side with wind, solar, etc.," he added.

That flexibility will benefit from distributed batteries and direct load control (DLC) programs, in which customers can sign up for programs that allow utilities to turn up their thermostats a few degrees on the hottest days.

Most utilities in the country use their assets at about a 30 to 35% range, but PGE is starting to exceed its peaks on that usage, and it would like to be able to bring its asset usage up to 40 to 60% while meeting peak demand, Bekkedahl said. That is going to require significant flexibility.

In September 2022, the Western grid hit its all-time peak demand at 167 GW, and prices were up to $2,000/MWh, when normally they sit around $100/MWh at most. Those kinds of peaks make demand flexibility very cost effective.

"So being able to flex with customers and what used to be demand response programs now become these flexible programs that can keep the lights on for everybody," said Bekkedahl. "And it also helps us to meet our greenhouse gas emission targets."

How High Can Prices Go?

Reflecting the system conditions to mass market customers can be handled in a variety of ways, from standard time-of-use rates that go up over predetermined hours and are lower in others, to just passing the wholesale price signal directly to consumers.

The experience of the retailer Griddy in the winter storms that knocked out power to millions of Texans in February 2021 often came up in interviews with *RTO Insider* as an unfortunate, cautionary tale. The firm had grown its customer base by passing along normally cheap wholesale rates without any markup to cover the cost of hedging. But then the winter storm came through, pushing up natural gas prices, knocking power plants offline and eventually leading the Texas Public Utility Commission to set prices at $9,000/MWh for most of a work week. (See *Texas Court Reverses PUC's Uri Market Orders*.)

Those wholesale prices led to some ridiculously high electric bills that customers ultimately did not have to pay; Griddy was forced out of the market, and its business model banned by subsequent legislation.

"ERCOT was living in this imaginary world

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DOE Ramps Up Support for Community Solar for LMI Communities

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were very infrequent, really high prices would automatically take care of all the issues that a capacity market takes care of in PJM," PJM Independent Market Monitor Joe Bowring said in an interview. "It clearly didn't work when push came to shove, and you had extreme weather. That's the problem because then prices are extraordinarily high, and you can do a massive amount of damage in a very short period of time to companies as well as the customers."

Some retailers ran into similar issues when PJM faced similar conditions during the polar vortex of 2014, though the RTO kept the lights on.

"In order for it to work, we have to have wholesale pricing that reflects shortages but does not reflect it to an extreme degree," Bowring said. "I mean, some economists say that really high prices are essential. I don't think that's true."

Prices can go up to $1,000/MWh, or maybe $2,000/MWh in extreme conditions, and still send the right signals to the market, including any customers on time-varying rates, he added. Prices also generally should not stay that high for long because they are only meant to go up to attract additional resources that tend to bring them back down.

Load-serving entities can design rates that would never expose their customers to such high prices, having a hedge kick in before prices shot up to their highest possible levels, Bowring said.

While the capabilities of smart meters were oversold, Bowring said, part of the reason dynamic pricing at retail has not taken off is that often third-party firms do not get access to the data that utilities have from those meters that would enable such programs. Bowring has long argued that DR should come from retail programs because he believes the wholesale DR programs PJM runs are far less efficient than that alternative.

Every time demand is triggered, it automatically leads to higher prices, which is the exact opposite effect demand is supposed to have, Bowring said.

"The place for demand side and where it can be most valuable to real customers is to have it on the demand side and to empower people to be able to reduce loads when they need to and to pay less for capacity and energy when that happens," he added.

Some Skepticism from Consumer Advocates

California is one state that has defaulted to time-of-use rates for its residential customers, but that program needed a carveout for low-income customers in the hotter parts of the state, such as the Central Valley, Marcel Hawiger, staff attorney for TURN – The Utility Reform Network, said in an interview.

"Dynamic pricing has the potential to lower rates if, and only if, any actual reductions in demand flow through to real reductions in utility spending," said Hawiger. "We hope that happens."

But charging more money for power when customers need it the most can also harm them, especially low-income customers who lack the ability to pay for the automation and changes in lifestyle needed to maximize its benefits, he added. When it comes down it, dynamic pricing is "using prices to ration a needed commodity."

"If you can afford it, you'll just use as much as you want on a hot summer afternoon and cool your home," Hawiger said. "And if you can't afford it, you'll cool less and have a warmer home because you can't afford it."

Many decry utility DLC programs, but they offer voluntary opportunities for customers to have their major appliances controlled by the utility in exchange for a rebate, which appeals to more customers and offers utilities more certainty over the resource, he added.

California only recently moved to default time of use rates for customers and TURN fought to exclude those who could not adequately respond. TURN looks forward to getting a look at the data on how the new rates in California have impacted customers, Hawiger said.

Where Else Has it Taken off?

Outside of California, some kind of time-varying rates have been fully deployed by Detroit Edison in Michigan, Xcel Energy in Colorado and the Long Island Power Authority in New York. Arizona Public Service and the Salt River Project in Arizona have high levels of participation in their programs, said Brattle Group's Sergici.

Those programs show that dynamic pricing can work, Sergici said, and it is just a matter of willpower between the industry and regulators to get it in place in more jurisdictions. The transition the grid is going through, with the growth in renewables and more distributed resources, will only grow its benefits.

The shift to renewables means that instead of generation having to constantly track shifting demand, generation will be intermittent and would benefit from having the demand-side track its output at least somewhat, he said.

"Pricing actually is a very great tool to moderate the pace of that investment cycle that we're going to go into because if you can manage some of the capacity growth through dynamic pricing, that means that you need to either defer that capacity build or you can even avoid some capacity build," Sergici said. "And that will only help to make this transition more affordable and reliable."

While dynamic pricing has been slow to take off, Sergici believes that is likely to change soon as the grid changes and more and more of the industry gets comfortable with it. The change will be like Ernest Hemingway's description of how a character went bankrupt in "The Sun Also Rises": "gradually then suddenly."

"I think that it's happened very slowly for a very long time," Sergici said. "And I am now seeing this big momentum. And I think that it will happen suddenly, in the next five years, that more and more utilities will decide to have time-varying rates to be the default rates for their customers." ■

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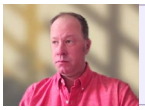

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FERC/Federal News

FERC's Handling of Environmental Justice Issues Debated in Court

DC Circuit Hears Appeal over Algonquin Gas Compressor Station Outside Boston

By James Downing

Opponents of a natural gas compressor station made a longshot bid to close the facility in oral arguments Thursday at the D.C. Circuit Court of Appeals that focused on FERC's handling of environmental justice concerns.

The compressor is part of Algonquin Gas Transmission's $627 million Atlantic Bridge Pipeline Project, which expanded capacity into the area.

The commission approved the pipeline expansion, including the compressor, on a peninsula in the city of Weymouth, Mass., in early 2017. In September 2020, the compressor station had two unplanned releases of natural gas, leading a number of groups to ask FERC to reconsider the project.

The commission then took the rare step of asking for briefings on the environmental justice impacts of the compressor after the certificate had been granted and upheld on appeal to the D.C. Circuit.

In an order dealing with those briefings issued in January 2022, FERC let the project keep its certificate. However, then-Chair Richard Glick said he thought the earlier order was likely a mistake, though it could not legally be overturned as the time for rehearing had passed and the D.C. Circuit had upheld that initial decision.

"Although it is cold comfort for the residents near the compressor station, I hope that this proceeding will serve as a turning point for the commission as we work to better consider, address and act on issues of environmental justice," Glick said during the 2022 briefings.

The attorney for Fore River Residents Against the Compressor Station, Michael Hayden of Morrison Mahoney, told the three-judge panel Thursday that FERC's decision on the briefings was a "Pyrrhic victory."

Since then, Glick was denied a nomination hearing before the Senate, which means FERC is more prone to deadlock on such cases with two members from each party, he added.

"I recognize it is a mountainous uphill climb for my clients [to] expect any change to occur before FERC," Hayden said. "So we don't expect it to happen voluntarily. It is only going to happen through the influence of the courts."

The judges asked questions focusing on the same procedural issues that FERC said tied its hands in reviewing the environmental justice concerns. Chief Judge Sri Srinivasan noted that Hayden and his clients were not challenging the 2020 order that authorized an extension of the project's certificate, but only the order on briefs that also dealt with the rehearing on the extension request.

FERC granted an extension request to the Atlantic Bridge project just 34 minutes after receiving it in the days following Christmas 2018, through an order issued by a staffer. Hayden complained that stopped his clients and others from even having a chance to challenge the firm's request for an extension.

FERC attorney Jared Fish noted that the staff was in a position to act because it had been monitoring the project's efforts to get state permits, which were also heavily litigated and delayed. The entire commission later confirmed that order, giving opponents a chance to weigh in on the merits of the extension. But they did not seek rehearing of that order, instead challenging the 2022 order on the briefings.

That 2022 order was an "unusual animal" that constituted a rare third round before the commission, Judge Patricia Millet said.

"I feel like it's … a little unfair to put on them not to know how to challenge it," she said.

FERC effectively asked the towns and residents to make their case; the commission seemed to agree with them; but then nothing was changed, Millet said.

"I credit FERC for having done the work and professed its need to change going forward," Millet said. "But … real people are getting lost in the technicalities of all of this."

Fish said the problem was that the petitioners asked FERC to reopen its decision granting a certificate, which is not something that it was legally able to do as the 60-day rehearing period had long ended and the court had already upheld the decision.

"You ask for new evidence, new briefing arguments about events that post-date the facility coming online, but it's not a reopening?" said Millet. "How is it not a reopening?"

Fish answered that FERC was looking for information to determine whether Algonquin was still in compliance with its certificate based on the unintentional releases of natural gas and other new information such as COVID's impact on environmental justice communities. The commission ultimately found no credible allegation that Algonquin was out of compliance with its certificate order or other permits, he added. ■

The Weymouth Natural Gas Compressor Station, on the town line between Weymouth and Quincy in Eastern Massachusetts | *Fore River Residents Against the Compressor Station*

FERC/Federal News

House Hearing Examines State of the Nuclear Power Industry

Bipartisan Support Seen for Legislation Addressing Advanced Reactor Deployment

By James Downing

House lawmakers heard from nuclear industry experts last week as they get started on legislation aimed at helping the deployment of advanced reactors across the U.S.

"To expand the industry, it is vital we encourage regulatory certainty and make sure our reactor licensing processes enable the safe and broad deployment of nuclear technologies," said Rep. Jeff Duncan (R-S.C.), chair of the House Energy and Commerce Subcommittee on Energy, Climate and Grid Security, at a hearing April 18. "This is especially important for advanced reactor technologies."

Nuclear power now provides about 20% of the country's electricity, including about half of its carbon-free energy, and it can help eliminate emissions on the grid, said the subcommittee's ranking member, Rep. Diana DeGette (D-Colo.). But several things need to happen for nuclear to remain a key part of the generation mix going forward, she said.

"The United States must develop a comprehensive science-based strategy to dispose of spent fuel — a strategy that does not cause harm to public health or our environment," said DeGette. "If we don't have a long-term permanent solution for disposing of nuclear waste, then we will struggle to be able to use this source of carbon-free electricity."

She said the other key challenge is figuring out what do with the existing fleet, which has seen some scattered retirements in recent years, but only one new nuclear plant coming online: Southern Co.'s Vogtle plant.

Once Vogtle's units are online, the country will have 94 reactors operating, and it will be important to extend their operating lives while securing them a more stable source of uranium, said Idaho National Laboratory's Jess Gehin.

"Currently, our nation imports 90% of our uranium needed for our reactor fleet," Gehin said. "This includes imports from Russia; eliminating these imports from Russia requires us to establish an expanded uranium-enrichment capability domestically and with our close allies."

Some of the proposed new reactors such as TerraPower's natrium reactor in Wyoming and X-energy's Xe-100 planned for deployment at a Dow Chemical facility on the Gulf Coast need a stable, domestic supply of high-assay, low-enrichment uranium that is not produced here at all, said Gehin.

Duke Energy has the largest fleet of 11 "regulated" nuclear units at its vertically integrated utilities in the Carolinas, and the North Carolina Utilities Commission has approved its early investment to consider building new, advanced reactors, said Regis Repko, the company's senior vice president of generation and transmission strategy.

"We plan to add unprecedented numbers … of solar energy, storage [and] wind power to the grid as we continue to retire our aging coal fleet," Repko said. "However, we must have firm, dispatchable resources, such as nuclear and natural gas, to support renewable energy resources. Our customers depend on us, and we must not jeopardize reliability or affordability in this transition."

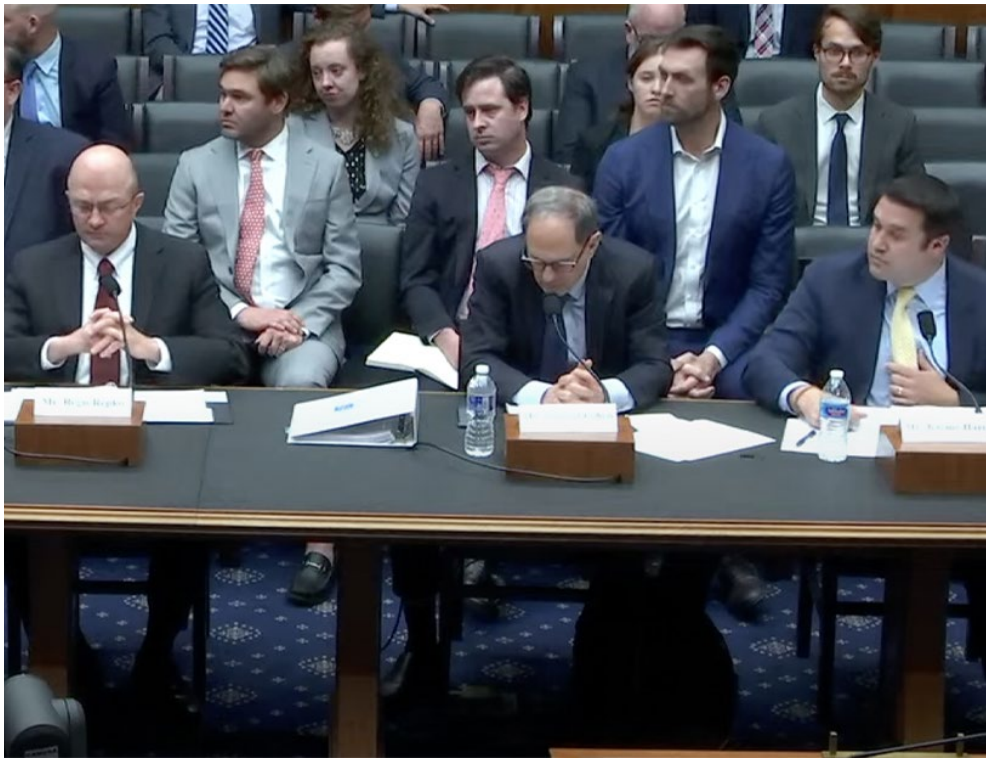
Duke's 11 plants are all set to retire between 2030 and 2046. To avoid losing those plants, which produce half the energy and 80% of the clean energy for its utilities in the Carolinas, the company would like to extend their licenses another 20 years. Duke also plans to build 8 GW of new nuclear power.

The firm plans to work with stakeholders and the Nuclear Regulatory Commission to ensure the licensing process for those new reactors is effective, efficient and in line with the safety of the new reactor designs, Repko said.

The bipartisan support seen at the hearing, recent advances in Europe and California's decision to extend the life of the Diablo Canyon nuclear plant all point to the increased support the technology has seen in recent years, said Clean Air Task Force Executive Director Armond Cohen.

"The problem is that we're just not moving at any scale and pace that's relevant to climate. To be relevant to climate, nuclear is going to have to be churning out something like 100 GW/year globally," said Cohen. "That's about in the range of where we were with coal and gas in a sustained way for a few years. We have to be really running at that scale. We're about 10 GW/year, so, we need to be 10 times where we are."

To have an impact on global climate change, the U.S. nuclear industry will need to export its technology because domestic emissions only amount to 15% of global emissions, he added. ■



Witnesses at last week's hearing on nuclear power | *House Energy and Commerce Committee*

FERC/Federal News

RTO Wind, Solar PPA Offer Prices Continue Rise in 2023

Regulatory, Financial Uncertainties Seen

By John Cropley

Offer prices for renewable power purchase agreements continued to rise in early 2023, ending the quarter more than one-third higher than a year earlier, renewable energy procurement platform LevelTen Energy reported last week.

On average, solar PPA offers increased 8.5% from the fourth quarter of 2022 and wind PPAs were up 4.9%, the company *reported*.

The numbers are derived from LevelTen's P25 Price Index, which represents 25th percentile PPA price offers that developers uploaded to the LevelTen Energy Marketplace — not actual transacted prices. A total of 260 price offers came from 207 renewable projects in six U.S. grid operators: CAISO, ERCOT, MISO, NYISO, PJM and SPP.

LevelTen said multiple factors affected the U.S. market in early 2023, including the uncertainty over the Inflation Reduction Act, evolving polices at all levels of government, rising capital costs and supply chain challenges.

Other factors had an outsized impact within individual markets.

Wind up in SPP; Solar Rises in MISO, NYISO

Wind offer prices jumped almost 21% in SPP during the quarter, for example.

"Growing wind penetration in SPP is having a material impact on market dynamics in the region," said Gia Clark, senior director of strategic developer accounts at LevelTen. "Wind facilities there are facing a more challenging financial picture as increasing wind generation drives down capture prices for wind assets operating there. Plans to expand transmission capacity between SPP and MISO are undoubtedly a step in the right direction, but approving, permitting and constructing such infrastructure will take years."

The biggest quarterly jump in solar PPA offer prices was in MISO, at almost 14%.

"The MISO interconnection study process now requires more upfront capital from developers to remove speculative projects from an overcrowded queue — adding costs and financial risk," Clark said. "Developers also have little certainty around the outcome of studies, which have increasingly included interconnection costs far higher than historical norms. Proposed projects in MISO factor these growing costs and risks into PPA prices."

LevelTen Energy reported last week that wind and solar power purchase agreement offer prices continued their steady increase in the first quarter of 2023. | *Shutterstock*

By a wide margin, the highest offer prices cited in the report were in NYISO, where solar PPAs surpassed $80/ MWh.

"NYISO has long been at the high end of pricing within the PPA market," Clark wrote.

Across the six regions indexed, the P25 offers were 36% higher for solar in the first quarter of 2023 than the first quarter of 2022 and 35% higher for wind, LevelTen said.

Developers' struggles to understand the implications of the IRA played a significant role in the market fluctuations, Energy Marketplace Vice President Rob Collier said in the news release. He noted LevelTen's wind index showed its first decrease in nearly two years in the fourth quarter of 2022 before rebounding in the first quarter of 2023.

"Rapidly evolving regulations at the federal, state and regional level are creating an unstable environment, making it difficult for developers to price PPAs and contributing to the price swings we're seeing in the market," he said.

Key details on IRA tax credits were *released* earlier this month.

"While this additional guidance on the IRA was very welcome, it does feel like we're taking one step forward and two steps back when evaluating all the new pieces of legislation that are poised to hinder renewable buildout," Collier said.

He singled out a proposal in the U.S. Senate to end the moratorium on solar panel import tariffs.

"While this proposal currently looks unlikely to succeed, solar developers now have to account for the possibility that tariffs may be reintroduced sooner than expected. That uncertainty is likely reflected in their pricing," he said.

Collier also cited multiple legislative proposals in Texas that would boost the fossil fuel industry and, in some cases, actively attempt to hinder renewables. "We have heard from some developers that they will be pausing development in ERCOT until a clearer regulatory picture emerges," he said. (See *Texas Legislature Moves Bills Remaking the ERCOT Market*.) ■

FERC/Federal News

Environmental Justice Issues on 2 LNG Facilities Split FERC Dems

Commission Approves Rio Grande and Brownsville Projects on Remand from DC Circuit

By James Downing

The fate of two LNG developments in Texas that had their approvals remanded to FERC drew out some disagreements among the regulators' two Democrats in orders posted Friday.

A three-vote majority during FERC's monthly open meeting Thursday approved the Rio Grande LNG (*CP16-454, et al.*) and the Texas LNG Brownsville (*CP16-116-002*) projects to move ahead after the commission conducted some additional analysis on their impacts on local environmental justice communities. Both projects are being built close to each other along the Brownsville Shipping Channel, which is on the southern edge of Texas' Gulf Coast.

The D.C. Circuit Court of Appeals had remanded FERC's approvals of the projects in August 2021 in the case *Vecinos Para El Bienestar de la Communidad Costera et al. vs FERC*. The court directed the commission to do a better job justifying its determinations of public interest and convenience in the two cases.

The Rio Grande LNG is being developed by NextDecade, while Glenfarne Energy Transition is building the Texas LNG project. The Rio Grande facility is expected to go online in 2026 and Texas LNG the year after that.

Chair Willie Phillips filed concurrences to the two orders, saying that FERC adequately responded to the issues on remand by including the projects' social costs of carbon and broadening the examination of environmental justice communities to those located within 50 km of either of the two power plants.

"While I recognize that certain of my colleagues would have preferred more process or less, I believe that the record assembled throughout the last year is an appropriate middle ground that represents an adequate basis to fully consider the issues the court remanded to us in *Vecinos* nearly two years ago," Phillips wrote.

Despite expanding the EJ scope to communities within 50 km of the site instead of just 2 miles, FERC continued to find that neither project would have any significant impacts.

One area where FERC did make some changes was to require both projects to take additional steps after they start partial operations but are still under construction to avoid exceeding National Ambient Air Quality Standards, as two emissions-generating activities would be occurring at the same time.

That mitigation shows how FERC is starting to focus on a complaint it heard at its recent Environmental Justice Roundtable about cumulative impacts of projects, Phillips said. (See *FERC Gets Advice, Criticism on Environmental Justice*.)

"We heard from several stakeholders, including community groups, about the importance of considering cumulative impacts — i.e., not just the air emissions directly caused by a particular project, but also those emissions in conjunction with the emissions from other sources within the region," Phillips wrote. "Today's order takes a critical step toward addressing that concern by requiring that the project sponsors develop a plan to ensure that incremental emissions impacts associated with these projects, on top of all sources, do not cause a NAAQS exceedance, thereby helping to protect communities, including environmental justice communities, that may venture near the projects."

An illustration of the planned Texas LNG facility along the Brownsville Shipping Channel | *Texas LNG*

Commissioner Allison Clements dissented on the orders, saying that FERC should have done supplemental environmental impact statements. Failing to do so renders the orders' significance determinations unsupportable, she argued. The commission also should have held public meetings to address the projects' environmental and other impacts.

Expanding the EJ scope identified hundreds of additional communities that never had a proper chance to weigh in on the project, warranting a new EIS, she said.

"The order imposes a new air pollution and monitoring condition that may prevent or reduce NAAQS violations," she said in each of the orders. "Although I agree that imposing this condition is a beneficial step to take, I cannot conclude that it will be sufficient to reduce cumulative air emissions to an insignificant level because the condition itself is vague, and we have had no public comment on whether it will be effective or what additional mitigation may be needed."

Clements also argued that FERC was missing a chance to implement its stated intentions from the recent Environmental Justice Roundtable.

"Considering our discussion at the roundtable of how to facilitate EJ communities' full participation, it is especially disheartening that the order rejects requests to hold public meetings, with Spanish translation, to hear communities' concerns about the project and our new analyses," Clements said.

Clements also disagreed with the majority's explanation for why FERC is not determining the significance of greenhouse emissions associated with the two projects.

The commission included social costs of carbon for the projects, but it said that tool was not designed to measure the impacts of individual projects, so it could not determine whether the emissions associated with the two LNG facilities are significant.

"I do not know whether the social cost of GHGs protocol or another tool can or should be used to determine significance," Clements wrote. "That is because the commission has not seriously studied the answer to that question. The majority has simply decided the method does not work, with no explanation of why the commission departs from the approach so recently taken in other certificate orders." ■

CAISO/West News

Inslee Approves 160 MW of Solar in Central Wash.

By John Stang

YAKIMA, Wash. — Gov. Jay Inslee last week said he has approved plans by Cypress Creek Renewables to construct two large solar farms in Yakima County in the central part of the state.

Cypress Creek will build the two 80-MW projects — High Top Solar and Ostra Solar — just west of the border between Yakima and Benton counties. The remote area is home to a just a handful of farms and 20 miles from the nearest town of Sunnyside. The two farms are expected to provide enough energy to power roughly 30,000 homes in the region.

Speaking at a press conference in the city of Yakima on April 17, Inslee noted that no farmland will be displaced by the projects. "Our team took great care to micro-site each project," Cypress Creek CEO Sarah Slusser added.

Sarah Slusser, Cypress Creek Renewables | © *RTO Insider LLC*

The two solar farms are expected to go online in 2025 and 2026, according to Tai Wallace, senior director of development at Cypress Creek. Wallace declined to provide a budget for construction, which is expected to create about 300 to 550 jobs, with about five to 10 remaining once the projects are completed.

Inslee has been leading to push to set up numerous wind and solar farms in Washington to wean the state from electricity produced by fossil fuels. His administration has calculated that the state will need to double its electricity production by 2050 to replace fossil fuel resources while accommodating an increasing population.

"We are the perfect place to lead the world in clean energy," Inslee said.

When questioned on whether he would uncritically approve wind and solar projects because of his strong support for alternative energy sources, Inslee replied: "We don't rubber-stamp these things. We look at them with a critical eye."

Washington law allows energy project developers to pick whether they want the state government or the appropriate county government to review their permit applications. Many applicants choose the state approach of going through the Washington Energy Facilities Siting Evaluation Council, which makes recommendations to the governor on whether to approve a project.

Washington Gov. Jay Inslee | © *RTO Insider LLC*

High Top and Ostra join two other eastern Yakima County solar farms set for construction. They include the 80-MW Goose Prairie project, approved by Inslee in December 2021, and the 94-MW Black Rock project, approved by Yakima County officials in May 2022.

The Black Rock project will share space with sheep that graze on the grass on the site, making it the second agrivoltaic site in Washington. The first such project mingling solar with farming is already online on the Colville Indian Reservation north of the Grand Coulee Dam. ■

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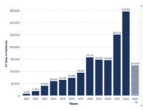

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CAISO/West News

FERC Tells PacifiCorp to Fix its Tx Rate Protocols

By Hudson Sangree

Aspects of PacifiCorp's transmission formula rate protocols limit transparency and the ability of interested parties to obtain information, FERC said Thursday in its latest ruling on last year's show-cause orders for five Western utilities to correct deficiencies (*EL22-38*).

Formula rate protocols provide customers and regulators with the ability to review and challenge formula rates for transmission service. In PacifiCorp's case, FERC found its protocols failed to adequately define the term "interested party," which partly determines who can participate in the formula rate information exchange.

"Without such a definition, PacifiCorp's formula rate protocols may not provide sufficient clarity and may provide PacifiCorp with the discretion to determine who is an interested party, and therefore appear to be unjust and unreasonable," FERC said in April 2022. It *ordered* PacifiCorp to justify its protocols or explain how it can alleviate the commission's concerns. (See *FERC Opens Probes on Western Tx Rate Protocols*.)

The commission also found a lack of transparency in the utility's protocols because they do not "do not require PacifiCorp to make a posting of the docket number assigned to its informational filing on its website."

PacifiCorp challenged both assertions. It argued that its protocols "contain a clear definition of 'interested party' because the preamble to the protocols states that 'interested party' means 'a transmission customer of PacifiCorp, a state commission in a state where PacifiCorp serves retail customers, any entity having standing in a [FERC] proceeding investigating the formula rate … and [FERC] staff.'"

FERC said that was insufficient. "The definition is limited to only those entities listed and also fails to include entities such as consumer advocacy agencies and state attorneys general," it said.

PacifiCorp also challenged FERC's finding that the utility's protocols "do not require [it] to make a posting on its website." It argued that it posts its annual update on its Open Access Same-time Information System (OASIS) website, pursuant to its protocols, which require the utility to put its annual update "in an accessible location" on its OASIS site.

FERC said that too was not enough. The utility's protocols must contain a specific provision for "posting on its website."

"Lacking such a provision is inconsistent with [an order in which] the commission directed MISO to provide notification of its informational filing through the email 'exploder' list to be maintained by MISO, and by posting the docket number assigned to each transmission owner's informational filing on the MISO website and OASIS within five days of such filing," FERC said.

"PacifiCorp's protocols do not contain a provision that requires PacifiCorp to post the docket number assigned to its informational filing on both PacifiCorp's website and OASIS within five days of such filing," the commission continued. "We find that posting the docket number assigned to PacifiCorp's informational filing on PacifiCorp's website, in addition to its OASIS site, is necessary to provide transparent access to the informational filing to interested parties that may not be familiar with PacifiCorp's OASIS site."

FERC ordered PacifiCorp to file a compliance filing within 30 days with proposed tariff revisions to rectify the shortcomings.

The four other utilities named in last year's compliance filings were Idaho Power, Public Service Company of Colorado, Public Service Company of New Mexico and Puget Sound Energy. FERC accepted tariff revisions from Idaho Power, PSCo and PSE, subject to further compliance filings, and concluded its proceedings against PNM. (See *PSCo, Idaho Power Comply with Show-cause Order*.)

The five cases are the latest in a series of numerous proceedings that FERC has initiated to investigate formula rate protocols since 2012, when it ordered MISO transmission owners to "file revisions to their formula rate protocols regarding the following areas of concern: the scope of participation (i.e., who can participate in the information exchange); the transparency of the information exchange (i.e., what information is exchanged); and the ability of customers to challenge transmission owners' implementation of the formula rate as a result of the information exchange (i.e., how the parties may resolve their potential disputes)."

The commission has repeatedly stressed the importance of ensuring the formula rate protocols meet those standards.

"The commission permits transmission service rates to be established through formulas," FERC explained in its April 2022 show-cause order to PacifiCorp. "Under a formula rate, the formula itself is the rate, not the particular components of the formula."

TOs adjust the formula inputs yearly, requiring "safeguards … to ensure that the input data is correct; that calculations are performed consistent with the formula; that the costs to be recovered in the formula rate are reasonable and were prudently incurred; and that the resulting rates are just and reasonable," FERC said in the show-cause order.

Formula rate protocols "provide transmission customers with specific procedures for reviewing and challenging rates," the commission said. "In order to fulfill this purpose, formula rate protocols must afford adequate transparency to affected customers, state regulators or other interested parties, as well as provide mechanisms for resolving potential disputes. Formula rate protocols therefore play an important role in ensuring just and reasonable rates." ■

PacifiCorp operates 17,100 miles of high-voltage transmission lines spanning 10 Western states. | *PacifiCorp*

ISO-NE News

New England Clean Energy Connect Wins Court Battle

Long-delayed Tx Line Would Bring 1.2 GW to Mass. via Maine

By John Cropley

Avangrid won another round Thursday in the long-running court battle over the $1 billion, 1,200-MW transmission line it is attempting to build in Maine.

A jury in Portland decided the developer had a right to resume construction of the New England Clean Energy Connect, which would bring hydropower from Quebec to Massachusetts.

Maine residents rejected NECEC in a November 2021 referendum, and groups such as the Natural Resources Council of Maine have mounted one legal challenge after another, stalling a project first floated in 2017.

But Maine's highest court ruled in August 2022 that the referendum might have been invalid. (See *Maine Court Ruling Gives New Life to Contentious Transmission Line*.) In November 2022, the high court overturned a lower court's ruling vacating a lease agreement for public lands. (See *NECEC Scores Another Victory in Maine's Highest Court*.)

The trial ending Thursday was held to resolve a question unanswered in the November ruling: Whether the developer had vested rights to complete construction of the line.

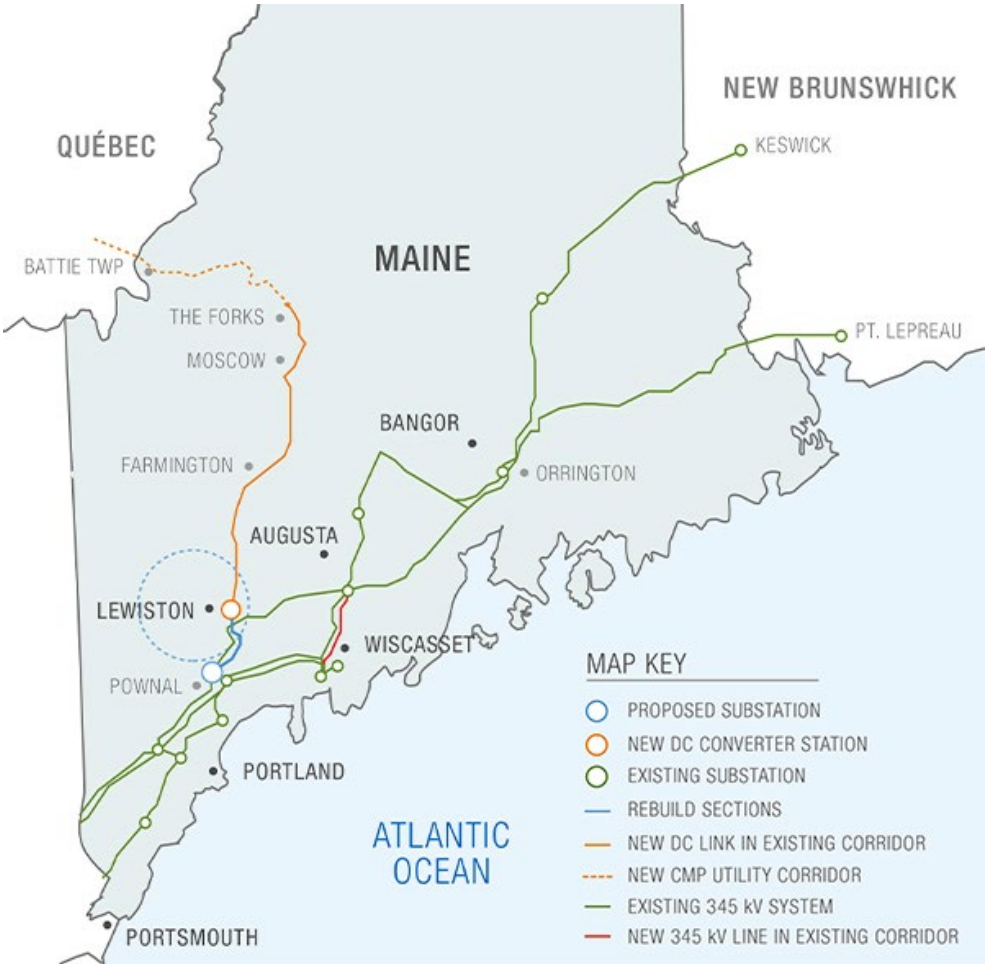
The jury unanimously decided that it does.

But that is not necessarily the final chapter in the saga, as NECEC opponents could appeal Thursday's verdict to the state Supreme Judicial Court. The Portland *Press Herald* noted that NECEC still faces appeals in state and federal court of permits issued by the state Department of Environmental Protection and U.S. Army Corps of Engineers.

Nonetheless, Avangrid welcomed the verdict as a victory.

"The jury's unanimous verdict affirms the prior rulings of the Maine Supreme Judicial Court that the New England Clean Energy Connect project may lawfully proceed," Senior Vice President Scott Mahoney said in a news release. "Even after repeated delays and the costs caused by the change in law, the NECEC project remains the best way to bring low-cost renewable energy to Maine and New England while removing millions of metric tons of carbon from our atmosphere each year."

ISO-NE welcomed the verdict as well.



A Maine jury ruled Thursday that construction could resume on the New England Clean Energy Connect transmission line. | *NECEC*

"We are pleased that this project can continue to move forward," Vice President Anne George said in a news release. "The New England states' ambitious climate goals will require building significant amounts of new infrastructure in a region where building infrastructure has been difficult. ISO New England looks forward to continuing our work with the New England states and other stakeholders, to making a clean and reliable future grid a reality."

NECEC would be part of the system operated by Central Maine Power, an Avangrid subsidiary. The roughly 145-mile line is expected to import approximately 9.5 TWh/year of electricity generated by Hydro-Quebec. Avangrid said it would save Massachusetts ratepayers $190 million a year while reducing emissions by the equivalent of 600,000 cars. Completion was initially projected in 2023 when work began in early 2021.

Fierce opposition erupted on multiple fronts in Maine, where some residents were concerned about the environmental impact of a project that would not directly benefit their state.

Other opposition was more subtle.

NextEra Energy, whose 1.24-GW nuclear power station in Seabrook, New Hampshire, might suffer in competition with an influx of low-cost electricity, *supported efforts to block the line*.

NextEra and Avangrid also squabbled over a circuit breaker at Seabrook that would be necessary once NECEC came online. The matter went to FERC — which ruled that NextEra could not refuse to install it — but the two had worked out an agreement by that point. (See *FERC Resolves NextEra-Avangrid Dispute over Seabrook Circuit Breaker*.) ■

ISO-NE News

ISO-NE Planners Outline Potential Solutions for 2050 Tx Overloads

By Rich Heidorn Jr.

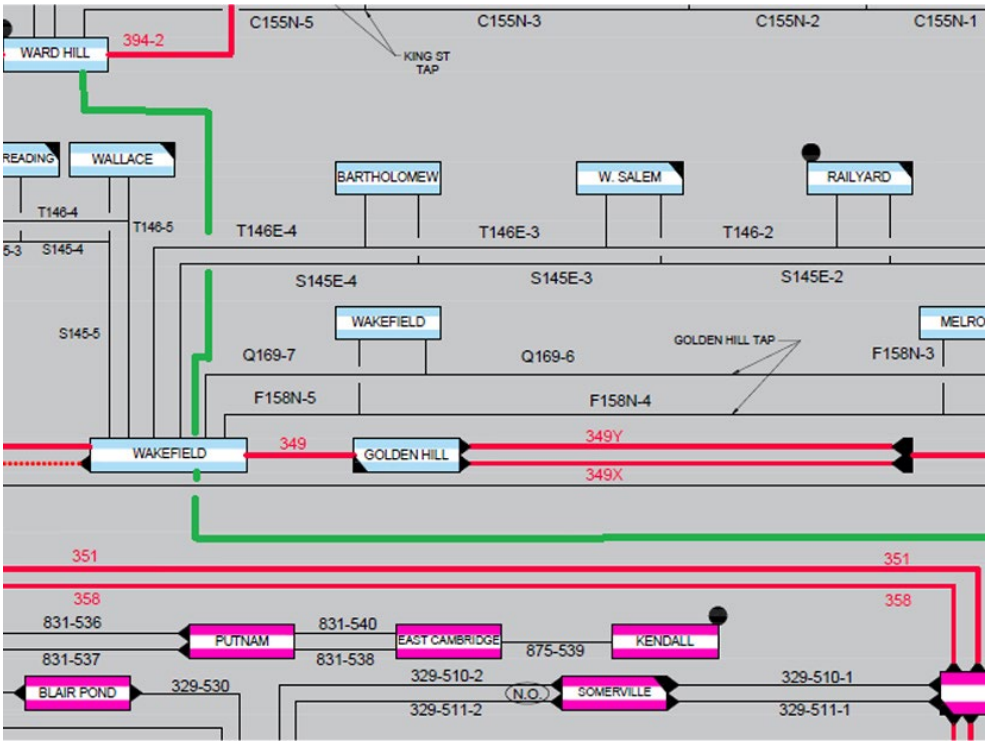
ISO-NE is studying line upgrades and new 345-kV and HVDC lines to address expected reliability violations in its 2050 Transmission Study.

Associate engineer Reid Collins *briefed* the Planning Advisory Committee April 20 on potential solutions for transmission overloads in Vermont and on north-south lines leading to Boston.

The 2050 Transmission Study, which resulted from a recommendation from the New England States Committee on Electricity's October 2020 "*New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid*," will identify transmission needs required to satisfy NERC, Northeast Power Coordinating Council and ISO-NE reliability criteria in 2035, 2040 and 2050. (See *States Demand 'Central Role' in ISO-NE Market Design*.)

The RTO presented an initial round of proposed solutions in Boston and southwest Connecticut in *December 2022*.

Planners are primarily seeking solutions for scenarios that include a 2050 winter peak load of 51 GW. Some parts of those fixes also are expected to address needs in 2035 and 2040. The RTO is also considering additional solutions for a "high winter" 2050 peak of 57 GW.



One potential transmission solution to accommodate high flows into the Boston area under both summer and winter peak conditions is the installation of a 345-kV AC line from Ward Hill to Wakefield Junction to Mystic (shown in green). | *ISO-NE*

Vermont Solutions

Planners are looking at three potential solutions for overloads resulting from large power transfers towards the Burlington area in northwestern Vermont.

Although many of the overloads can be resolved by rebuilding overhead lines, several underground or underwater sections would be very costly or difficult to rebuild, such as the PV-20 115-kV line running under Lake Champlain to Plattsburgh, New York, which cannot be fixed with the equipment that currently controls its flows.

The potential solutions are:

- Upgrade the PV-20 line from New York from 115 kV to 230 kV and build a new 115-kV line parallel to line K43. The underground and underwater segments of PV-20 are already built for 230 kV; only overhead segments would need to be upgraded. Collins said this would likely be the cheapest solution — involving the fewest miles — and could improve NYISO-ISO-NE transfer capability, reducing resource curtailments in northern New York. But it would be complicated by requiring construction in New York.
- Build a new 345-kV line from Coolidge to Essex, which would limit construction to New England and avoid many overhead rebuilds and the most difficult underground rebuilds. However, it would involve significantly more new construction than other solutions, at a higher cost, even though much of the new transmission could follow existing rights-of-way.
- Build a new 345-kV line from New Haven to Essex and a new 230-kV line from Granite to Essex. It would avoid many overhead rebuilds and most underground rebuilds and be limited to New England while requiring less new transmission construction than the Coolidge-Essex solution. But it would require the addition of two new transformers, rather than one, at Essex. It also would limit the use of the Granite 115-kV PARs to control flow on the existing 230-kV lines in Vermont and New Hampshire.

North-South Solutions

Many of the major lines running from Maine and New Hampshire into Massachusetts face overloads from excess generation in the north and large loads in southern New England.

In the primary solution set, and in the 2035 and 2040 solution subset, all the overloads can be fixed with rebuilds. In the 57 GW scenario, many of the overloads would be too severe to be addressed by rebuilding.

The potential solutions include:

- Re-route lines 375 and 3038 to avoid Surowiec and go straight from Maine Yankee to Buxton with a new 345-kV line for Surowiec-Timber Swamp-Ward Hill. A second 345-kV line for Timber Swamp-Ward Hill might be needed to fix the high winter scenario. In addition to reducing the need for rebuilds on existing lines, the new 345-kV line across major interfaces should improve voltage and stability performance. However, right-of-way (ROW) for some segments of the project would be cramped, and it would result in increased reliance on a single 345-kV ROW for moving power north to south.
- Add an HVDC line between the Surowiec 345-kV line and the Mystic 345-kV line. The solution also requires re-routing of lines 375

ISO-NE News

and 3038 to form a new Maine Yankee-Buxton 345-kV AC line. It would resolve many of the north-south transfer and Boston import issues while avoiding increased reliance on a single 345-kV ROW. This solution, combined with several 345-kV line rebuilds would solve north-south overloads as well as most Boston overloads in the primary solution set as well as the 2035 and 2040 solution subset. But additional solutions — possibly multiple point-to-point or offshore network HVDC lines — will be needed to meet the high winter peak for 2050.

- HVDC lines between Orrington or Surowiec, Maine, and Ludlow or Manchester, Vermont also are being tested to address north-south and east-west constraints in the high winter scenario. Although it would fix "significant numbers" of north-south overloads, it would not solve the Boston import issues, and the lengthy line could be expensive and difficult to site.

Boston Import Solutions

Boston is expected to experience import constraints during high flows into the area under both summer and winter peaks. Each season and each year studied found underground violations in at least some scenarios.

Planners project more overloads for the 2040 winter peak than for 2050 because the growth in wind injections into Boston will outpace the increased load.

Among the options being considered are:

- Building an HVDC line from Ward Hill to Mystic, which would significantly reduce the number of overloaded underground elements in Boston without needing to upgrade them directly. It would avoid possible short-circuit impacts of new 345-kV AC lines. But it could be "quite expensive," the ISO said, and finding space for HVDC converter stations near Ward Hill and Mystic could be difficult.
- Adding a 345-kV AC line from Ward Hill-Wakefield Junction-Mystic could be cheaper than the HVDC option but it would be less effective at solving underground overloads in Boston.

To fix overloads on lines serving Boston from the south, planners are considering adding series reactors on the two existing Stoughton-K Street cables or adding a third Stoughton-K Street line, which would be more effective but also more expensive.

National Grid plans to spend an estimated $138 million to replace 178 wood structures with new steel structures on its 115-kV transmission line between the Harriman #8 substation in Readsboro, Vt., and the Adams #21 substation in Adams, Mass., including this damaged wood utility pole. | *National Grid*

HVDC Line Configurations

The 2050 Transmission Study also is considering multiple options for HVDC lines, some with a point-to-point configuration (e.g., Surowiec-Mystic). "Others are implied through wind injections modeled as large generators at transmission-level buses," the RTO said. Although the study is considering the lines individually, "it is also possible that these lines could be connected together to form an offshore grid," the RTO added.

ISO-NE has hired Electrical Consultants Inc. to develop detailed cost estimates for some of the complex solutions. The RTO told ECI to avoid creating double-circuit towers, especially on the 345-kV network. The RTO also requested undergrounding lines as needed to avoid using eminent domain or displacing residents. It hopes to ease siting by placing new overhead lines along existing highway and railroad corridors.

"Detailed cost estimates will help to inform the region on both the costs and physical impacts of the projects examined," the RTO said.

Next Steps

The RTO asked for feedback on the 2050 study presentation by May 5, with submissions to *pacmatters@iso-ne.com*.

Solution development work will continue through the end of this year in parallel with ECI's cost estimates. The RTO's next presentation will be in late summer or early fall, and a draft 2050 Transmission Study report is scheduled for release in November.

Asset Condition Projects

Also at the PAC *meeting*, National Grid, Eversource Energy and Vermont Electric Power Co. (VELCO) outlined plans to spend a combined $169 million on transmission line refurbishments:

- National Grid *estimates* it will spend $138.3 million on its 12-mile E-131 115-kV line between the Harriman #8 substation in Readsboro, Vermont, and the Adams #21 substation in Adams, Massachusetts, in an area with steep terrain. Constructed in 1925 and updated in 1971, it includes 209 structures, including a tap to the Bear Swamp substation. The company will install new steel structures to replace three lattice towers and almost 200 wood structures that showed signs of top splitting and woodpecker damage. The project, which will also include access road improvements, has an estimated in-service date in the third quarter of 2027.
- Eversource will *replace* wood structures with light-duty steel poles on a 5.4-mile section of 115-kV lines 1132 and 1505 on a shared right-of-way between Canterbury Switchyard and Killingly Station and the Brooklyn Tap in Connecticut. "If you replace [some structures] with wood, the woodpeckers will just find the next piece of wood out there," said Eversource's Chris Soderman. The estimated cost is $13.4 million, and the proposed in-service date is the first quarter of 2024.
- VELCO will *replace* 105 of 245 wood H-frame structures, most with steel H-frames, on its K43 115-kV line from Williston to New Haven. The 21-mile line was built in 1954 and originally operated at 69 kV. The cost is estimated at $16.9 million, and the company is targeting a 2026 completion. ■

ISO-NE News

ISO-NE Expects Slower, Then Faster, Load Growth

Final CELT Report Due May 1

By Rich Heidorn Jr.

ISO-NE's revised load forecast sees slower growth in the next few years because of economic turbulence, followed by accelerating growth from electrification.

The RTO's *draft* 2023 Capacity, Energy, Loads, and Transmission (CELT) report, presented at the April 20 Planning Advisory Committee meeting, projects the RTO's net winter 50/50 peak will hit 25,133 MW by 2031, a 10% increase over last year's CELT projection for that year. The net forecast subtracts the impact of energy efficiency and behind-the-meter PV.

The RTO predicts a 2031 gross 50/50 winter peak — including BTM resources and passive demand resources that participate in the ISO-NE markets — of 27,646 MW, almost 7% above its 2022 forecast. For 2023, however, ISO-NE projects a gross winter peak of 22,053, almost 1% below the 2022 projection.

The summer forecasts for 2023 and 2024 also have been reduced from last year with the summer gross 50/50 forecast reduced by 1% in both 2023 and 2024.

The new report incorporates Moody's February 2023 macroeconomic outlook, which projects the region's economic output will be about 3% less than its previous forecast through 2032 because of the war in Ukraine, increased fossil fuel prices and the Federal Reserve's interest rate increases to tame inflation. The final CELT report will be released May 1.

Lead data scientist Victoria Rojo told the PAC that the RTO expects winter loads to grow faster than summer loads over the next decade.

"In the outer years, you see a lot more growth [in winter] than you do in summer because now in our electrification forecast, we have both the heating and transportation components, which increased significantly over last year's forecast," she said.

By 2032, the 50/50 net load forecast shows the winter peak less than 800 MW below the summer peak. The 50/50 measure is a probabilistic forecast intended to be indicative of normal weather conditions in each season. "So if, for example, you had a summer with cooler than normal summer weather conditions, and in that same year, you have a winter with more extreme than normal winter weather, it's possible that you can see a winter peaking system much sooner than our 50/50 forecast would dictate — possibly even by the end of the forecast horizon," Rojo said.

RTO system planners have made no major changes to the specification of the summer/winter demand forecast models since CELT 2020, Rojo said. However, methodologies for both the heating and transportation electrification forecasts have been updated since CELT 2022.

"On the heating side, we've completely overhauled our methodology. And on the transportation side, we've made some more targeted updates to pieces of the methodology," Rojo said.

For heating, the RTO changed how it performs demand modeling, as well as how it forecasts the adoption of electrification. It includes a greater variety of building types and technologies through use of the National Renewable Energy Laboratory's residential and commercial real estate stock data sets.

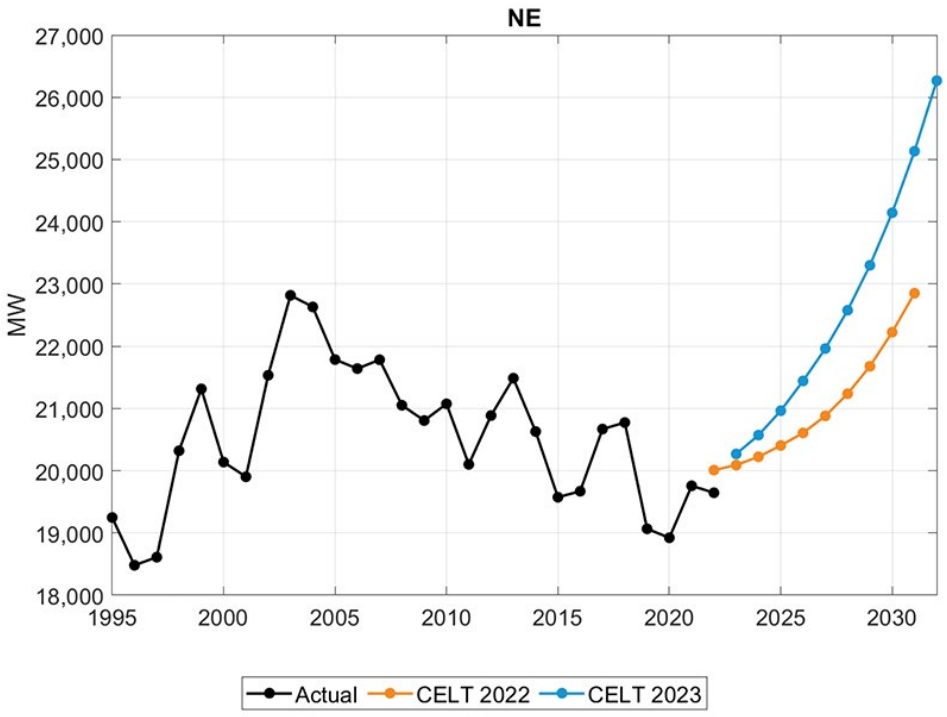
Planners are now including the impacts on commercial real estate "whereas in the past forecasts, we focused exclusively on the residential sector," Rojo said.

Residential properties are forecast to adopt electrification at different rates depending on their current heat source, with oil-heated homes transitioning faster than propane and natural gas properties lagging both.

The RTO's forecast shows faster adoption of full heating electrification in the commercial sector while the residential buildings are expected to see more partial heating electrification.

"It's easier to install a ductless mini-split heat pump … especially when you have buildings that have [hot water] systems that have no ductwork [for heating or air conditioning]," Rojo said. "It's easier to just do the partial application, which can be a room or zone in the house.

"The expectation is that when a business … chooses to electrify a building, they're doing it as more of a business decision versus just kind of taking advantage of certain incentives [available to residential homeowners]. It's more of a business choice, and it's more likely to be a whole business transition," she added. ■



Winter net 50/50 peak forecast | *ISO-NE draft 2023 Capacity, Energy, Loads, and Transmission report*

GCPA 36th Annual Spring Conference

Overheard at the GCPA Spring Conference

By Amanda Durish Cook

HOUSTON — The Gulf Coast Power Association's annual spring conference April 18-19 revolved around how Texas and its coastal region can become a hotspot for energy innovation.

Anne Choate, ICF | *© RTO Insider LLC*

Anne Choate, executive vice president for energy, environment and infrastructure with consulting firm ICF, said the Gulf Coast can "further cement its goal as the innovative energy epicenter" of the world.

She said the region can impel clean energy infrastructure and long-term change for climate stabilization "in the same way we've been successful at repairing the ozone layer." Choate said the industrial-heavy Gulf Coast has "powerful" potential in geothermal energy, carbon capture and green hydrogen technologies.

"It's going to be a lot of work. We're going to look like we're gliding across the water, but we're going to be paddling furiously underneath," she said, saying it has the potential to make Silicon Valley look "quaint."

"I think the Gulf region will be one of the most active regions, not just in the U.S., but globally, in carbon capture and sequestration," predicted Frederik Majkut, senior vice president of carbon solutions at SLB New Energy.

Brett Kerr, Calpine | *© RTO Insider LLC*

Brett Kerr, Calpine's vice president of external affairs, said a healthy carbon capture industry will require a nexus of a young workforce, academics and financial capital.

"I truly believe that carbon capture can do for the Gulf Coast what tech did for the Bay Area," he said.

Kerr said the Inflation Reduction Act's passage means that carbon capture now makes financial sense.

"It's always been good policy, but for the first time it really makes good business sense to pursue these projects," he said.

Kerr said when power generation has a carbon capture facility backfit, it becomes no different from a wind or solar resource, save for an "on/off switch." He said firm delivery will make retrofitted gas plants attractive to buyers.

Mark O'Donnell, Occidental's assistant vice president of power, said decarbonizing the region's natural gas plants will undoubtedly take carbon capture and a conversion to green hydrogen. He warned that at ambient temperatures, it takes three times the amount of hydrogen to produce the same amount of energy generated by natural gas.

"It's not like you can't overcome hurdles, but carbon capture, you've seen it and it's proven," O'Donnell said.

Molly Bales, Form Energy | *© RTO Insider LLC*

Form Energy Senior Business Development Manager Molly Bales said long-duration storage can de-risk utilities' increasingly renewable generation portfolios.

Bales said her company is pioneering a rechargeable iron-air battery capable of storing power for a little more than four days at costs on par with legacy power plants. She said the batteries cost about one-tenth of lithium-ion battery facilities. The iron-air batteries "breathe" in oxygen from the air and convert iron metal to rust when discharging; the process is reversed when charging, with an electrical current converting the rust back to iron while the battery expels oxygen.

Bales said Form Energy realized that the grid needs multi day storage to firm up renewables and navigate mounting multiday weather events.

"This is an opportunity to build a whole new ecosystem," Bales said. Form is planning to build its first battery factory in Weirton, West Virginia, a former steel town.

Bales said Form could be eyeing Texas for such a factory as soon as 2025. "We're really excited about what's happening in the next few years," she said.

Inflation, Interest Curbing New Assets?

Julien Dumoulin-Smith, head of U.S. power utilities and clean energy research at Bank of America Securities, said "rampant" inflation and increasing interest rates are complicating the outlook for new asset construction.

"It's not over," he said of stubborn inflation. "You heard it here first."

Dumoulin-Smith, a frequent questioner during utility earnings conference calls, said investments in carbon capture and sequestration "should be taken seriously" while green hydrogen is "similarly quite real."

"This stuff ain't cheap, but $85 per ton does wonders on the cost," he said, referring to the newly enacted tax credit for carbon capture and storage.

However, Dumoulin-Smith said capacity prices and resource adequacy's costs "have gone from zero to 100" seemingly overnight.

"I think we're heading materially higher," he predicted.

Dumoulin-Smith said that he expects Texas, Oklahoma and Arkansas to be most affected by generation retirements as the Environmental Protection Agency ratchets up regulations.

"We see a litany of new EPA rules ahead that could impact the generation stack again," he said. EPA's proposed crackdown on coal ash through effluent-limitation guidelines stands to move the needle on retirements, Dumoulin-Smith said.

He said 2023 will be a "catch up" year for solar panel supply as it recovers from last year's trade issues. He said interconnection queue wait times also remain a problem.

"Bottom line is, you need to be very skeptical about when these projects can get done," Dumoulin-Smith said, stressing that companies must consider how much time and money it will take to get grid treatment versus situating resources on the distribution system.

Advances in Tx Capacity

LineVision CEO Hudson Gilmer said there is a "mismatch" between today's grid needs and planned transmission that's five-to 10 years away. He said even Texas, which typically gets lines built faster than the rest of country, lags on new transmission capacity.

Gilmer said LineVision uses non-contact sensors and analytics to employ dynamic line ratings that allow 30-40% more power to flow through lines. He said utilities don't always have to use "disaster plan" line ratings.

Gilmer said bottlenecks in interconnection

GCPA 36th Annual Spring Conference

queues have led utilities to his company.

"While no one wants to be the first to deploy a new technology, when they see their peers adopting it … there's a tipping point," Gilmer said. He added that dynamic line ratings have had a perception problem, with fears they would "cannibalize" the need for new transmission lines. Gilmer said contrary to that belief, the grid needs new firm capacity, even with the assistance of dynamic line ratings.

"It's not an either-or situation. It's an 'and' situation," he said.

Stephen Conant, vice president at startup VEIR, said his company focuses on overhead superconductors that can increase line capacity without expanding rights-of-way or increasing transmission tower heights. He said superconductors are at an "exponential" adoption stage, though he admitted the costs aren't yet competitive with normal conductors.

"There's a huge need to build transmission capacity, but it's difficult to site, as some as you have experienced," he told attendees.

Conant urged the audience to remember that at one point, it was difficult to imagine the development of 18-MW offshore wind turbines when compared to the 1.5-MW turbines that were once the standard.

"In the time it takes you to build your next transmission line, you're going to be giving me a very serious look," he said.

Speakers with Differing Market Views

Texas Public Utility Commissioner Kathleen Jackson said she believes the state's energy future will come down to a blend of "a lot of little things," not a singular technological solution. She urged attendees to focus on the "data, science and economics" when standing up new technologies.

Jackson urged Texas utilities to focus on energy efficiency and investing in new assets. She said the state's growing population demands forward planning and making the most out of existing generation.

"We have 1,200 people coming to Texas each day," she said. "Nobody is bringing power with them."

Carrie Bivens, ERCOT's Independent Market Monitor, said growing load uncertainty and renewables dominance in Texas means that ERCOT is currently making avoidable out-of-market commitments. She said she expects the energy-only market to effectively send price signals that stir respondents and said she doesn't foresee a "fundamental" market breakdown on the horizon.

A Power Pitch demonstration at the GCPA annual spring conference April 18 | © *RTO Insider LLC*

Former FERC chair Joseph Kelliher expressed disappointment during a keynote address over how RTO executives lead wholesale markets today.

"When I was at FERC, we expected RTO leadership to be more FERC-like. And I know that sounds obnoxious," he said, explaining that grid operators should make unpopular decisions at times.

"I think some RTOs have become more dedicated to stakeholder consensus than they do toward market integrity," he said. "I think some RTOs have lost their way, and that's their current approach."

Kelliher said capacity markets, especially those in the Northeast, are disappointing and producing suppressed prices that won't support new generation entry. He said grid operators might consider scrapping the markets altogether and focus instead on long-term contracts.

GCPA Debuts 'Power Pitch'

The GCPA conference featured a new concept in Power Pitch, where early-stage energy technology companies competed for a $5,000 award styled after the "Shark Tank" television show. *Bodhi*, a software app that offers real-time, personalized updates on homeowners' residential solar projects, took the award home to Austin.

The judging panel consisted of three professional energy investors, with the audience weighing in via an interactive survey. Criteria included the presentation's quality, potential impact on the industry, and the business model's potential success. Judges asked about the comparative costs of new technologies, risks of being copied, ease of manufacturing and target customers.

Other contestants included:

- *Calwave Power Technologies*, which plans to churn out submerged xWave boxes to harness the power of ocean waves and complement power output at existing offshore wind sites;
- *Criterion Energy Partners*' distributed geothermal system designed to be co-located on heavy industrial sites in Texas and Louisiana;
- *Revterra*'s grid-synchronous, inverter-free kinetic flywheel battery that serves as a buffer between the grid and EV charging; and
- *Dash Clean Energy*'s zero-emission hydrogen fuel cell storage facility, which is trying to ensure peaker plants can replace retiring older generation.

Houston-based energy startup incubator Greentown Labs vetted the contestants. ■

MISO News

FERC Terminates MISO Show-cause Order

By Amanda Durish Cook

FERC approved MISO's reworked ratio for its capacity auctions April 17, a day before the grid operator began accepting its first offers. It said the RTO's recalculation ensures it will be "deriving [seasonal accredited capacity] values" consistent with its tariff.

The order also terminated the commission's show-cause order as it found that MISO satisfactorily recalculated the ratio, which will mean some thermal generators are entering the planning year with lowered capacity accreditation values (*EL23-46*).

MISO's Resource Adequacy Subcommittee convened April 18, the same day that staff opened the offer window, delayed by FERC's show-cause order, for its first seasonal planning resource auction. (See *MISO Unveils New Seasonal Auction Timeline, Ratio*.)

Scott Wright, MISO's executive director of resource adequacy, said MISO staff is "doing everything [they] can" to carry out the more complicated seasonal auction in a timely fashion. He said he appreciated stakeholders accommodating the dynamic auction schedule. MISO expects to reveal auction clearing prices May 19, about a month later than usual.

MISO's Durgesh Manjure said that following the auction, MISO stands ready to hear stakeholders' advice on how to improve it for subsequent years.

"Resource adequacy at MISO is definitely a team sport," he said.

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

The auction's delay hinged on an unforced capacity-to-intermediate seasonal accredited capacity ratio that it uses to determine supply. The ratio helps MISO navigate its new seasonal landscape, converting resources' seasonal accreditation into unforced capacity terms. The grid operator expresses its planning needs according to unforced capacity values.

The RTO was forced to redo the ratio after a computer error caused some previously exempted planned outages to be counted against some resources' accreditation values. The grid operator asked FERC that it be allowed to revise individual accreditation values but leave the systemwide ratio alone, as some market participants had already relied on the flawed ratio to enter bilateral capacity arrangements outside of the voluntary auction.

However, FERC ruled that the ratio had to be updated with resources' latest seasonal accreditation values.

FERC said MISO's tariff doesn't afford it "with discretion to decide whether to update the ratio; rather, MISO must calculate the ratio consistent with the formula set forth in the tariff."

FERC said while it was "sympathetic to arguments" from Vistra and the Electric Power Supply Association (EPSA) that market participants already relied on the erroneous ratio to make supply plans for the planning year, those arguments cannot supersede MISO's duty to follow rules outlined in its tariff.

Earlier this month, Vistra and EPSA, a trade group representing competitive suppliers, asked FERC to terminate the proceeding and issue an order to prevent MISO from updating the ratio and lowering resources' capacity credits. Both said a reworked ratio stands to affect careful supply plans that load-serving entities have buttoned up for weeks based on MISO's first published capacity values. (See *Vistra, EPSA Protest MISO's Show-cause Order*.)

FERC also said the ratio recalculation doesn't intrude on MISO's tariff provision requiring LSEs to opt out of the auction and submit a fixed resource adequacy plan before the upcoming a planning year.

Finally, the commission said it disagreed with ESPA's claim that it was interfering with MISO's auction.

"Rather, we are ensuring that the correct values for auction parameters are being used," FERC said. ■

MISO News

NextEra Asks for Rehearing of Canceled Competitive Project

By Amanda Durish Cook

NextEra Energy is continuing its efforts to salvage the only competitive regional transmission project MISO has recommended in its South region, filing a request last week at FERC to stay the commission's recent order that formally terminated the project.

NextEra Energy Transmission Midwest (NEET) requested on April 17 both a rehearing and a stay of FERC's March order that allowed MISO to abandon the $115 million, 500-kV Hartburg-Sabine Junction project in East Texas (*ER23-865*). MISO approved the project in 2017 but determined last year that the project's benefits faded after recent generation additions in the region. (See *FERC Rejects Last-ditch Effort to Save Tx Project*.)

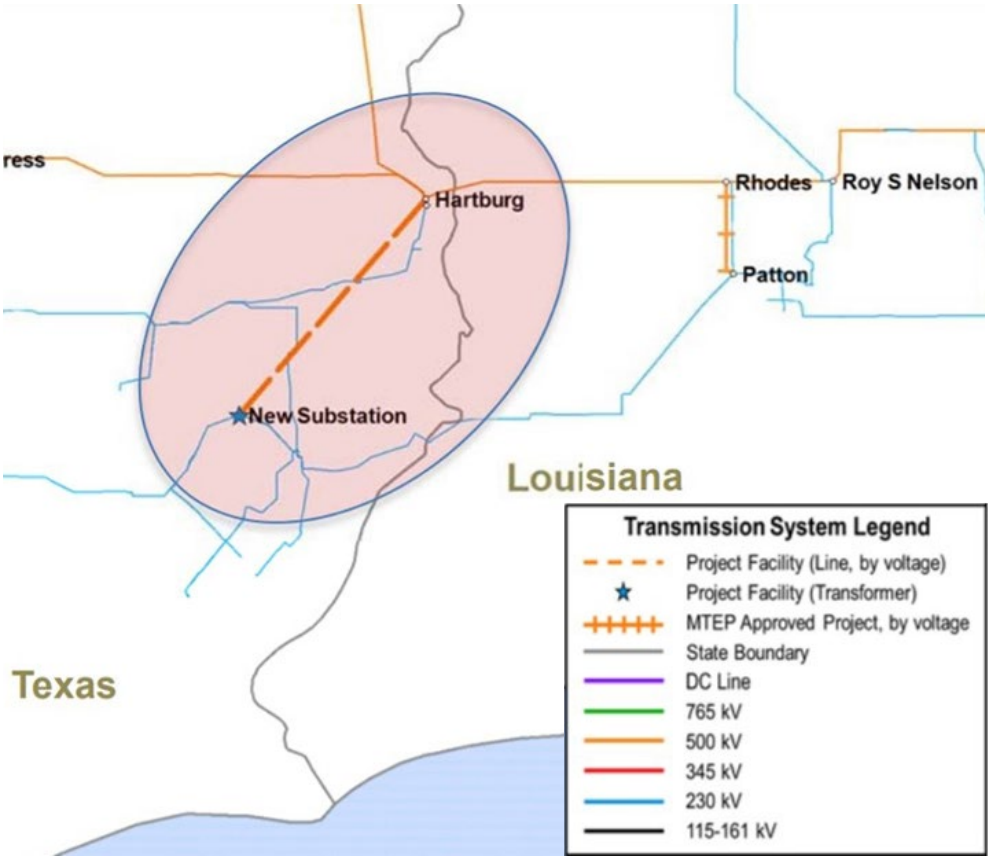
NEET said the stay is necessary while it "fully exercises its right to judicial review" of not only the March order but also its pending appeal of Texas right of first refusal legislation that prompted MISO's re-evaluation of the project.

The 5th U.S. Circuit Court of Appeals last year ruled that the state's 2019 law giving incumbent transmission companies the first rights to build new power lines is unconstitutional. Texas has petitioned the U.S. Supreme Court to review that decision. (See *Texas Petitions SCOTUS to Review ROFR Ruling*.)

NEET said it is likely to succeed in the case and maintains that FERC's cancellation of the project was premature.

"Absent a stay of the commission's order, the project will be removed from MISO's regional transmission planning models and cannot easily be reinstated, regardless of whether NEET Midwest prevails on rehearing or on appeal," NEET argued. "Granting a stay will avoid imposing these substantial and irreversible consequences on NEET Midwest and will not unduly harm third parties."

The transmission developer said MISO will likely remove the project from planning models for its interconnection queue and 2024 Transmission Expansion Plan (MTEP) cycle, which will begin later this year.



Hartburg-Sabine map | *MISO*

"Once removed from MISO's MTEP and generator interconnection planning models, it will be difficult, if not impossible, to reinstate the project, particularly given the disruptions and delays to MISO's annual transmission planning and interconnection studies that reinstatement will likely cause," NEET said.

The NextEra subsidiary added that interconnection customers are unlikely to be harmed if the project is kept in planning models because no generation projects currently rely on it for grid access. NEET said scrubbing the project from MISO "prior to final resolution of the legal issues surrounding it" may require customers to pay abandonment costs.

The developer said it's at a point where it has spent significant money to participate in MISO's competitive bidding process and to develop the project, but that it may be unable to recover even a portion of its costs.

NEET argued that FERC simply took MISO at its word that keeping the project on its books would distort transmission planning. It said the grid operator's tariff language triggering a project's re-examination is more prescriptive and includes "reliability- or service-related issues that may 'be jeopardized as a result of the delay.'" The developer pointed out that MISO continues to incorporate the unfinished Cardinal-Hickory Creek line in the Midwest that was first recommended in 2011 in its models.

It also said FERC should have more seriously weighed not taking immediate action on the project while the Texas ROFR litigation is pending. ■

Midwest news from our other channels

Michigan Dems Seek to End Coal-fired Plants by 2030

NetZero Insider

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

NYISO News

NYISO Seeking to Increase Emissions Transparency

New Regulation Requirements also Proposed for Renewables

By John Norris

NYISO on April 17 *presented* the Installed Capacity Working Group/Market Issues Working Group (ICAP/MIWG) with proposed methodology for measuring implied marginal emission rates (IMERs) to increase transparency around New York's emissions output by providing real-time data.

The ISO chose the IMER "heat rate" methodology to measure emissions production over other options because, staff said, it is highly variable and granular, performs well in grids with clearly defined marginal fuel types, and helps identify persistent congestion patterns.

The methodology uses LMPs, fuel prices, emissions costs, and variable operation and maintenance costs as inputs to estimate the implied heat rate, which is then used to estimate the real-time zonal IMER in tons of carbon per megawatt-hour for a given implied marginal fuel.

Stakeholders requested NYISO publish real time marginal and average zonal emissions rates data to help them comply with state energy and climate legislation, particularly Local Law 97, which set strict carbon reduction standards for large New York City buildings. (See *NYC Proposes Rules to Implement Building Emissions Law*.)

Aaron Breidenbaugh, director of regulatory affairs at CPower Energy Management, asked why stakeholders had requested this project, to which William Acker, executive director of the New York Battery and Energy Storage Technology Consortium, responded that his organization, along with state agencies and other stakeholders, need this information to support LL97 compliance.

"We need to have at least hourly marginal numbers available for the accounting under [LL97], and secondly, it's valuable to have something that is forward looking and that isn't simply scorekeeping but is actually actionable by people managing buildings in New York City," Acker said.

NYISO will return to the ICAP/MIWG either next month or in June to share additional information on the methodology's inputs and is targeting the fourth quarter to deliver the functional requirement specifications.

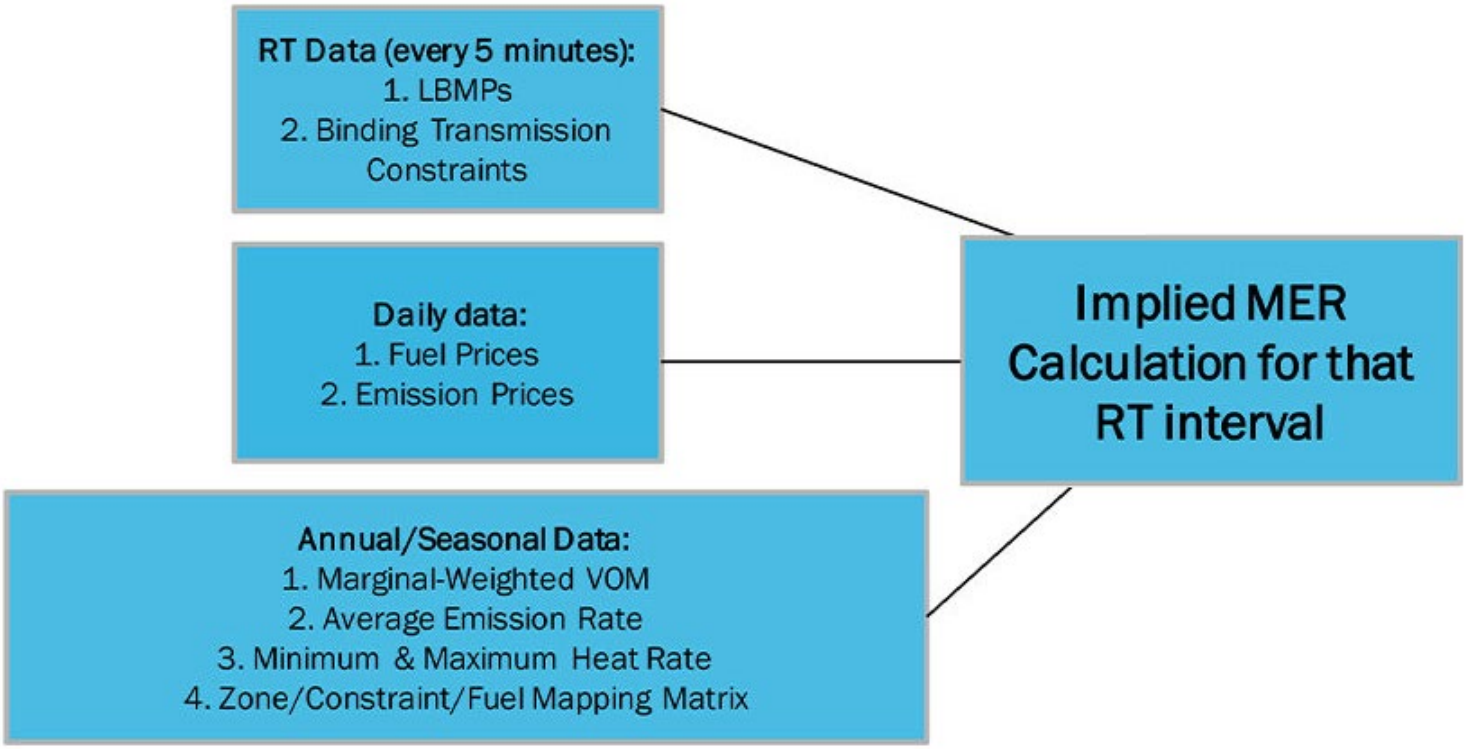
Renewable Regulation Requirements

NYISO also *presented* the ICAP/MIWG with proposed revisions to the regulation requirements for renewable resources in the state.

As New York installs more wind and solar projects, the ISO has been required to regularly update its regulation requirements, starting in *2010* and again in *2016*, to ensure that these resources are not negatively impacting its ability to balance the bulk power system or disrupting voltage requirements.

NYISO modeled two scenarios that predict the total amount of installed nameplate capacities of land-based wind (LBW), offshore wind (OSW) and solar at the end of a given year: Scenario 1 projects that 3,000 MW of LBW, 125 MW of OSW and 7,651 MW of solar will be installed by 2024; while Scenario 2 projects 3,700 MW, 125 MW and 9,768 MW, respectively, will be installed by 2026.

NYISO is proposing that Scenario 1's set of new regulation requirements be implemented on June 1, and that Scenario 2 be implemented in 2025. The ISO would send stakeholders market notices in case capacity levels approach those in the scenarios earlier than projected. ■



Proposed methodology for calculating implied marginal emission rates | *NYISO*

NYISO News

Sally Talberg Joins NYISO Board of Directors

By John Norris

NYISO last week *announced* that veteran energy regulator Sally Talberg had joined its Board of Directors as its ninth member.

Talberg has 25 years of experience in energy and environmental regulation and has served in multiple top-level capacities.

She was appointed by Michigan Gov. Rick Snyder (R) to the Public Service Commission in 2013, serving as its chair from 2016 to 2020. During that time, she was a member of both the National Association of Regulatory Utility Commissioners and the U.S. Department of Energy's State Energy Advisory Board. In 2016, Talberg served as president of the Organization of MISO States.

Talberg left the Michigan PSC near the end of 2020 to join ERCOT's Board of Directors, first as an independent director for the first month of 2021 and then as its chair beginning in February — just before Winter Storm Uri hit and nearly caused the collapse of the Texas Interconnection. She, along with three other independent directors of the board, resigned

Sally Talberg | *Michigan Public Service Commission*

later that month after fierce criticism from state residents about ERCOT's out-of-state leadership in the aftermath of the storm. (See *ERCOT Chair, 4 Directors to Resign*.)

Talberg did, however, begin her career in Texas, after graduating from Michigan State University. She worked at the Lower Colorado River Authority while pursuing her master's in public affairs from the Lyndon B. Johnson School of Public Affairs at the University of Texas at Austin. She went on to work at the Texas Public Utility Commission as an electric policy analyst.

"As a former state commissioner and former adviser to commissioners at the Texas and Michigan commissions, she has a unique appreciation for the importance of market design, infrastructure planning, pragmatic regulation and stakeholder engagement," NYISO said.

Currently, she runs her own consultancy, Talberg Policy Solutions, and serves as a senior policy fellow at Public Sector Consultants.

The NYISO board consists of 10 members; Talberg's appointment leaves just one vacancy.

"It is a privilege to welcome Sally to the NYISO's Board of Directors. Her extensive experience will be invaluable as the board guides the NYISO during this historic period of industry change," Chair Daniel Hill said in a statement. "We look forward to Sally's contributions as we work to meet the state's climate mandates, ensure grid reliability and competitive wholesale markets during the grid in transition." ■

NYISO News

NY PSC Approves $810M Con Ed Clean Energy Hub in Brooklyn

Utility Preparing for Demands of EVs, Building Electrification

By John Cropley

The New York Public Service Commission on Thursday *approved* construction of a scaled-back version of Consolidated Edison's proposed Clean Energy Hub in Brooklyn.

Con Ed originally proposed the hub in April 2022 (*20-E-0197*) as a $1 billion landing point for 6 GW of electricity generated by the wind farms New York wants to build off its coast.

In December 2022, the utility supplemented that proposal with a smaller alternative that it framed as a step needed by mid-2028 to maintain reliability in the area amid rapid electrification of buildings and transportation. The cost was significantly lower, at $810 million: $773 million for the hub itself, and $37 million to prepare the facility to serve as a make-ready point of interconnection for 1.5 GW of offshore wind power.

The PSC unanimously approved the supplement Thursday as necessary to maintain electric reliability.

The commission also rejected the original hub plan — which was still alive — because there was no evidence offered to show that routing 6 GW of power to the hub is feasible. There was demonstrated interest from developers in doing so but no indication it is physically possible.

The proposal was attractive because of the scarcity of real estate to build such a facility in New York City. Con Ed proposed to build it on a site occupied by an office building and three retired gas turbine generation units, adjacent to its Farragut substation.

But objections were raised during the public comment period. Many questioned the feasibility of running multiple HVDC cables beneath the East River to reach the hub. Others said the hub was not the product of a competitive solicitation process, such as NYISO's Public Policy Transmission Planning process, and therefore might not result in the lowest price tag, or the price tag least likely to change.

But the PSC unanimously approved the scaled-down version of the hub proposal, agreeing that it is the only potential solution to the projected needs in the area as the city and state press forward with their clean energy transition.

The PSC denied New York City's request to delay a decision to await further analysis, saying the proposal is time-sensitive. It also rejected the city's contention that the hub would not be cost-effective and would not promote resilience.

The hub is only the first of several 345-kV substations that will be needed in the city, the PSC countered. Installed generation capacity statewide is expected to double from 43 GW in 2019 to 90 GW in 2040, with much of the load growth in New York City. The commission determined that the cost of building the hub will be borne by Con Ed ratepayers, as it is designed for purposes of reliability of service to them.

If the hub's benefits expand beyond Con Ed territory into the larger realm of the state's climate protection goals, such as through offshore wind, the utility can petition for an alternative cost-recovery mechanism to spread the costs beyond its rate base, the commission said, but it said it is skeptical at this point that it would agree to such a change.

Commissioner John Howard focused on the costs involved, and noted that Con Ed has estimated it will need to spend $60 billion to prepare its service area for the energy transition.

He applauded the inclusion of the word "skepticism" in the order and suggested also that the city should not be allowed to reap a property tax windfall from all the infrastructure that will be needed in the next few decades.

A Department of Public Service staff member estimated the smaller $810 million hub would have a $48 million annual property tax bill.

PSC Chair Rory Christian said Thursday that New York state's energy landscape is in a period of fundamental change and that infrastructure investments must keep pace with proactive planning.

"Priority has shifted to ensuring increased levels of renewable, clean sources are integrated into the grid while polluting sources are being phased out," he said. "To make sure the system continues to serve customers with the level of reliability that our modern economy demands, we know that additions and modifications to the utilities' transmission and delivery infrastructure will be needed, as well as equitable methods for recovering the costs of such additions." ■

Con Edison has been authorized to build a Clean Energy Hub adjacent to its Farragut Substation on the Brooklyn waterfront. | *Shutterstock*

NYISO News

NYISO Operating Committee Briefs

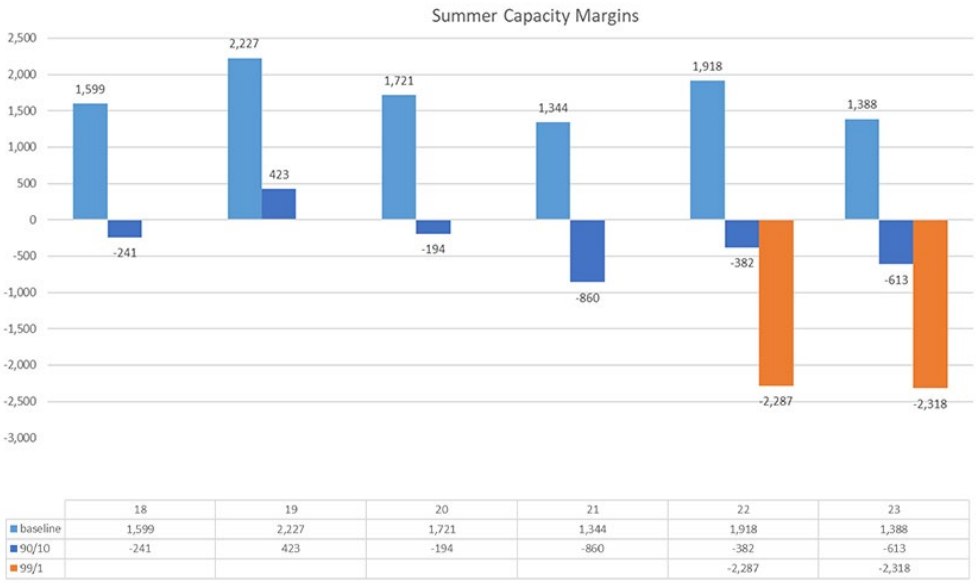
Summer 2023 Capacity Assessment

NYISO on Thursday updated the Operating Committee about forecasted summer conditions, assessing that while it has enough capacity for this summer and the near future, margins are declining over time as the grid transitions to clean energy.

Under its baseline forecasted conditions, the ISO will have about 1,400 MW of surplus capacity. In the event of extreme conditions that would decrease that margin as low as 2,300 MW, the ISO is covered by up to 3,100 MW of emergency operating actions.

NYISO is currently conducting site visits to assess readiness for summer conditions and ensure potential outages coordinated with ISO staff to minimize any reliability impacts, said Aaron Markham, vice president of operations.

The ISO expects 652.3 MW of generation to be deactivated by July 1, mostly in Zone J (New York City) as a result of New York state's peaker rule. About 940 MW of new wind and solar generation is expected to come online throughout the summer. Markham also said that new transmission into the city resulted in increased margins for the zone.



	18	19	20	21	22	23
baseline	1,599	2,227	1,721	1,344	1,918	1,388
90/10	-241	423	-194	-860	-382	-613
99/1					-2,287	-2,318

Summer capacity margins for New York from 2018 to 2023 | *NYISO*

March Operations Report

NYISO informed the OC that March was a "pretty quiet month."

The grid experienced a peak load of 19,881 MW on March 14, which Markham said was "quite a bit lower than the capability period peak." There were no high-level curtailments.

Installed behind-the-meter solar also "keeps ratcheting up," according to NYISO, with 84 MW added since the last OC meeting.

Inverter-based Resources Standard

The New York State Reliability Council (NYSRC) briefed the OC about a proposed rule establishing minimum requirements for inverter-based resources (IBRs) over 20 MW.

The NYSRC said their draft rule, PRR-151, is necessary because more IBRs have sought interconnection in New York and recent problems seen in other RTOs show that without sufficient regulatory guidance, these resources can have outsized negative impacts across the grid when not performing properly. (See *New York Considering Standards for IBRs*.)

It asked that comments and questions be sent to *herb@poweradvisorsllc.com* by this Thursday.

Renewable Regulation Requirements

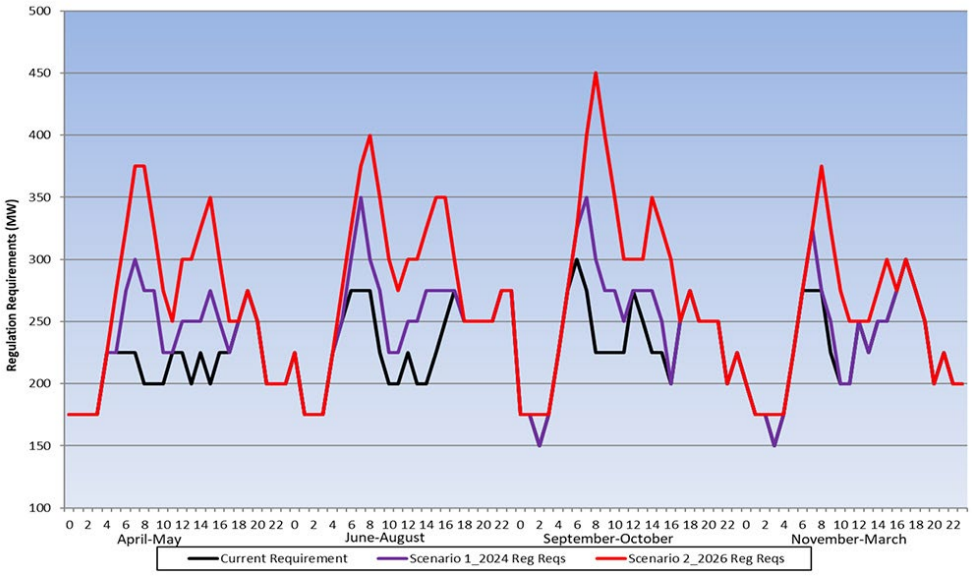
The committee approved NYISO's proposed updates to the regulation requirements for renewable resources and their proposed implementation timelines.

The ISO said the updated requirements will help balance bulk power concerns as net load grows and intermittent resources increasingly make up most of the state's energy mix. (See related story, "Renewable Regulation Requirements," *NYISO Seeking to Increase Emissions Transparency*.)

The first set of new regulation requirements, Scenario 1, will be implemented on June 1, and the second set, Scenario 2, will be effective June 1, 2025.

NYISO promised to update its presentation to specify Scenario 2's implementation date and to provide stakeholders with advanced notices should timelines change. ■

— John Norris



Current and proposed regulation requirements for renewable resources | *NYISO*

NYISO News

NYISO Study to Examine Future Winter Security Risks

Manual Updates for DER Aggregations Also Discussed at ICAP/MIWG

By John Norris

An upcoming fuel and energy security study will examine the combined impacts of electricity generation trends and extended cold snaps on NYISO's system reliability, the Analysis Group (AG) *told* the ISO's Installed Capacity Working Group/Market Issues Working Group (ICAP/MIWG) on Friday.

The main thrust of the study is to identify circumstances under which available resources will be insufficient to meet both load and required reserves before emergency actions as the New York grid transitions to a greater dependence on renewable resources.

For the near-term, the study will assume NYISO's continued reliance on fossil fuel-fired generation, followed by increasing reliance on weather-dependent and variable resources over the long term. Within that context, it will examine 17-day cold periods in winter 2023/24 and two other future winters.

AG plans to use historical weather and load data, literature reviews of other RTOs, projected resource demand and supply forecasts, and assumed worst-case scenarios to assess the potential risks associated with NYISO's transition and the impacts extreme weather events could have on the grid.

The assessment will use criteria such as net load and reserve needs, gas generation availability, interzonal transfers, and environmental constraints to identify hourly energy surplus and deficits in New York at a zonal level.

Paul Hibbard, a principal with AG, said the company conducted a similar study in 2019 that found "a continued reliance on fossil fuels was necessary in the near term," and that NYISO could build more transmission to "address potential reliability risks associated with increasing variable generation." (See "Fuel Security Study," *Analysis Group Presents NYISO Carbon Pricing Study Plan*.)

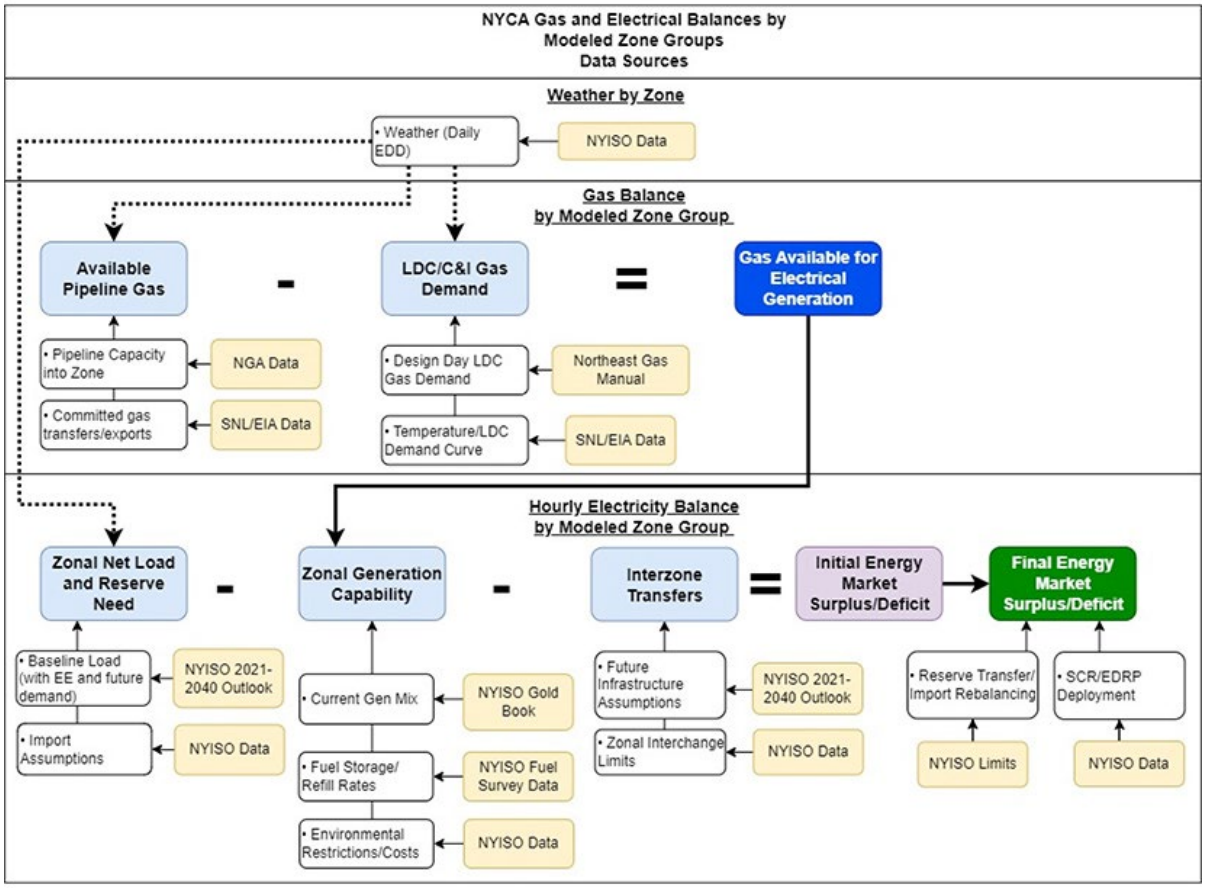
Mark Younger, president of Hudson Energy Economics, asked whether the upcoming study will offer any noteworthy changes from the 2019 study.

Hibbard said the company is "kind of repeating what was done previously" given that the methodology and basic source material are similar, but the underlying risk scenarios determining the current study's assumptions are different because of the passage of time.

Hibbard said the goal of the new study is to "identify circumstances under which resources may be insufficient to meet demand plus reserves without taking emergency actions."

AG will return in May to give a more detailed presentation on the study's assumptions, data and scenarios.

In early summer AG will share the study's initial findings and recommendations, then present the final report later that season.



High-level overview of Analysis Group fuel and energy security study | *Analysis Group*

ECBL Aggregation Manual Updates

NYISO also *presented* the Friday ICAP/MIWG with draft *manual* updates for sections covering the economic customer baseline load (ECBL) that adjust the calculations to a five-minute basis for distributed energy resources.

The ECBL, which was implemented into NYISO markets in 2018, provides an estimated energy baseline for the ISO to measure the amount of demand reduction supplied by a demand-side resource participating in a day-ahead demand response program.

This update was one of a series of aggregation manual updates, and NYISO will return to share additional manual revisions on April 27. ■

NYISO News

FERC Orders More Compliance Filings from NYISO for Order 2222

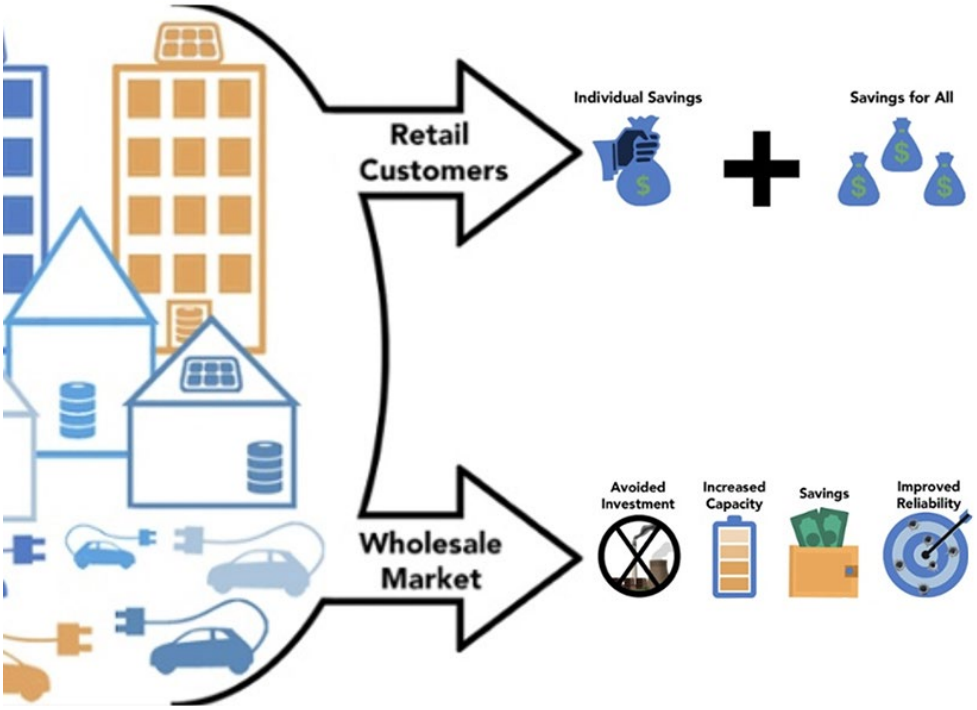
FERC on Thursday partially accepted NYISO's second compliance filing for Order 2222, directing the ISO to submit another within 30 days to correct several inconsistencies in its tariff revisions allowing distributed energy resource aggregations to fully participate in its markets (*ER21-2460-003*).

The commission found NYISO's revisions listing what constitutes a small generating facility "appear to refer to the same type of interconnection" in two different places. The commission told NYISO to either remove one of the listings or explain why including both is not redundant.

FERC also found that NYISO had revised the definition of energy resource interconnection service (ERIS) in only one of the two relevant sections of its tariff, leaving the other unchanged.

Third, FERC said that NYISO's revisions concerning market participation agreements, although partially settled, still included language from the first compliance filing that had already been found to be noncompliant. FERC said NYISO needed to remove "language requiring aggregators to attest that the aggregation has been authorized by the distribution utility and relevant electric retail regulatory authorities to participate in NYISO's markets."

Lastly, FERC directed NYISO to submit informational filings every six months detailing its stakeholder process in developing ancillary service market rules allowing DER aggregations to participate until Dec. 31, 2024, by which it needs to submit yet another compliance filing that includes the proposed rules. (See *FERC Clarifies CAISO, NYISO Order 2222 Rulings*.)



DER benefits come from getting more use out of resources that would otherwise be limited to meeting onsite needs. | *AEE*

FERC partially approved NYISO's first compliance filing in June 2022, with the ISO submitting its second later in November. In the next month, the commission granted NYISO an extension until 2026 to fully complete Order 2222 implementation, although the ISO said at the time that it might not need that long. (See *FERC Gives NYISO Until 2026 to Complete Order 2222 Compliance*.) ■

— John Norris

Northeast news from our other channels

New York Celebrates Completion of Renewable Projects — NetZero Insider

AES and FirstEnergy Ask to Close Warrior Run Coal Plant Early — NetZero Insider

Vermont Gas Utility Explains its Effort to Electrify Customers — NetZero Insider

NY Steps Up Planning for Medium- and Heavy-duty EVs — NetZero Insider

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NYISO News

FERC Approves Batch of Line Ratings Compliance Filings

By RTO Insider Staff

FERC on Thursday approved the compliance filings of six transmission providers, including those of NYISO and CAISO, with Order 881, though it found that most of them had failed to sufficiently explain their timelines for calculating and submitting their required ambient-adjusted line ratings (AARs).

Issued in December 2021, and upheld in May 2022, Order 881 directed transmission providers to end the use of static line ratings in evaluating near-term transmission service, and implement AARs for short-term service and seasonal ratings for long-term service (*RM20-16*). (See *FERC Orders End to Static Tx Line Ratings*.)

FERC did not specify a specific timeline by which transmission providers must submit their ratings, but it did order them to submit their own in their compliance filings. The commission had argued that providers "already manage similar timing issues" regarding other topics such as load forecasts, renewable energy production and generation bid deadlines, and that deadlines for AAR calculation and submission should be "not significantly different" from those they already calculate.

But though it approved their filings, the commission found that Arizona Public Service (*ER22-1863*), Black Hills Power (*ER22-2303*), Louisville Gas & Electric and Kentucky Utilities (*ER22-2305*), and Tampa Electric (*ER22-1546*) each failed to include such a timeline.

NYISO (*ER22-2350*) said that it expects to calculate AARs on a 48-hour basis, with submissions by transmission owners to be provided to the ISO hourly. But it also told FERC that it and TOs are "still developing technical procedures describing the mechanics of AAR submissions," the commission said.

However, in each of these five cases, FERC acknowledged that "these timelines may not be determined until closer to AAR implementation and therefore that additional time may be necessary to comply with this requirement." NYISO and the four utilities will need to submit another compliance filing by Nov. 12, 2024, ahead of their deadline for implementation of July 12, 2025.

In Tampa Electric's case, the commission also took issue with the utility's proposal to backdate its table of contents changes to June 1, 2022. FERC said this plan "could cause confusion because it would reference a section of [its tariff] that is not in effect." To prevent potential misunderstandings, FERC set the table of contents revisions to take effect on the same day as the new tariff. However, the commission did suggest it was open to a future filing from the utility explaining why an earlier effective date would be justified.

"Our Order No. 881 compliance orders are bright points in today's meeting," Commissioner Allison Clements *tweeted* that afternoon. "They represent the beginning of a bigger opportunity to squeeze more juice out of our existing system at a relatively minimal cost to customers, using grid-enhancing technologies."

NYISO

The commission had also ordered RTOs and ISOs to create systems and procedures to allow transmission owners to electronically update transmission line readings at least hourly and give TOs the ability to use more advanced dynamic line rating technology, which takes into account more factors than just air temperature when calculating ratings, if they choose.

FERC found that both NYISO and CAISO mostly complied with these directives. But both did not adequately explain certain definitions, the commission said.

Although NYISO provided for seasonal line ratings, it did not "define 'seasons' to include no fewer than four seasons in each year," FERC said. The commission also nixed the ISO's proposal that its TOs, rather than itself, were responsible for sharing transmission facility ratings and methodologies. NYISO has until June 19 to submit a compliance filing correcting these two deficiencies.

NYISO had also proposed revising its day-ahead market congestion settlement procedures to quantify the impacts of when the ratings employed in the market differed from those used in transmission congestion contract auctions. But FERC rejected this proposal as well, though without prejudice, noting that NYISO could file these revisions as a separate proposal.

"While the commission in Order No. 881 acknowledged a connection between the transmission line rating requirements and financial transmission rights markets, the commission declined to direct any changes to financial transmission rights markets, and therefore these revisions fall beyond the scope of this compliance proceeding," FERC said.

CAISO

CAISO's (*ER22-2362*) proposal only partially complied with Order 881's requirement that transmission providers post line rating exceptions or temporary alternate ratings on its Open Access Same-Time Information System or another password-protected website, FERC said. And the ISO's proposed definition of "transmission line ratings" fell short of the order's requirements, it found.

The ISO had proposed defining "transmission line rating" as the "maximum transfer capability of a transmission line, computed in accordance with a written transmission line rating methodology and consistent with good utility practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits), as well as technical limitations of the transmission system (such as system voltage and stability limits)."

"CAISO asserts that the definition encompasses transmission line ratings for electric system equipment that includes more than just overhead conductors … [such as] circuit breakers, line traps and transformers," FERC noted. But the commission said the definition needed to reflect the order's wording.

"While CAISO states that its proposed definition encompasses electrical system equipment beyond just overhead conductors, we find that the absence of tariff specificity renders the proposed definition unclear on this point," the commission said.

FERC said CAISO's proposal also only partially complied with Order 881's requirements for designating exceptions and alternate line ratings.

"CAISO proposes to coordinate with [participating transmission owners] in their development of exceptions or alternate ratings for both near-term and longer-term transmission service for the set of circumstances set forth in the *pro forma*" tariff, the commission noted. "However, CAISO does not propose tariff language stating that exceptions will be re-evaluated by the transmission provider at least every five years, nor does CAISO explain the absence of such language."

FERC gave CAISO until June 19 to submit another compliance filing for these failings. ■

Michael Brooks, Tom Kleckner, Devin Leith-Yessian, Holden Mann, John Norris, Robert Mullin and Hudson Sangree contributed to this report.

PJM News

FERC Approves PJM Variable Maintenance Adder Proposal

By Devin Leith-Yessian

FERC last week approved a PJM proposal to overhaul how generators can represent variable operating and maintenance (VOM) costs in their energy market offers (*ER23-1138*).

The proposal sought to divide generators' maintenance adders into "major" and "minor" buckets and allow the owners to opt for newly created default values for minor maintenance. The proposal also would create default values for operating expenses, which — like minor maintenance — have a tendency to be fairly uniform year-over-year, PJM said. (See "MRC Approves VOM Package," *PJM MRC Briefs: Nov. 16, 2022.*)

The April 18 order said the proposal streamlines the process for approving maintenance and operating costs, while retaining market power protections. The order granted PJM's requested June 1 effective date.

"PJM's proposal offers market sellers flexibility while maintaining essential safeguards to mitigate opportunities for market sellers to exercise market power," the commission said.

Under the status quo rules, generators are required to submit documentation of any maintenance and operating expenses they're seeking to include in their cost-based offers, which the filing said causes "significant administrative burdens for both market sellers and PJM."

The maintenance history used to calculate corresponding adders includes costs going back 10 to 20 years, which results in time spent reviewing and approving those costs each year, PJM said. The proposal allows expenses for major maintenance to be approved with an "expiration date," after which costs must be resubmitted.

Major maintenance expenses would also be required to be resubmitted if they are no longer accurate due to expenses rolling off the 10- or 20-year historical period.

Generators would still have the option to submit unit specific costs for minor maintenance and operating expenses. However, PJM argued that the process of submitting, reviewing and approving expenses typically takes several months on behalf of sellers, RTO staff and the Independent Market Monitor.

Default adders would not be created for nuclear and hydroelectric resources, which PJM said lack the historical data being used to create the adders for other resource types, nor for wind and solar, which the filing said typically don't submit maintenance adders. PJM may seek to create those adders in the future.

The proposal defines major maintenance as "overhauls, repairs, or refurbishments that require disassembly to complete of boiler, reactor, heat recovery steam generator, steam turbine, gas turbine, hydro turbine, generator, or engine." Minor maintenance is described as "typically performed when there is a component failure or prior to a component failure due to limited remaining component life" and that can be completed while the generator is operating or during short shutdowns.

Monitor Protests Inclusion of Avoidable Costs

The Monitor argued that PJM's proposal incorrectly allows maintenance costs that are avoidable costs and should be included in capacity offers to be instead submitted as short-run marginal costs in the energy market.

The issue arises from a vague definition of maintenance costs, the protest states, allowing all costs "directly related to electricity production" to be included in energy offers.

To support its position that maintenance costs should be included in capacity offers, the Monitor pointed to a filing to allow the Indian River 4 coal-fired unit to provide service after its deactivation request, in which it seeks to receive a lump-sum payment for its maintenance-related investments rather than recovering those expenses through the energy market. The protest also states that 53% of marginal units in the energy market included maintenance costs in their 2022 energy market offers.

PJM responded that its proposal doesn't seek to change the existing requirement that maintenance adders can only be recovered in the energy market and through the avoidable cost rate (ACR) in the energy market. It also argues that the Monitor's objections have been raised in past dockets and constitutes a collateral attack on the commission's 2019 order approving PJM's maintenance adders revisions (*EL19-8*).

In last week's order, the commission noted that it had addressed the concerns raised by the Monitor in 2019.

"The wear and tear of operating a resource is typically based on the number of starts or run hours, and the maintenance intervals can be influenced by resource output levels. As such, it is reasonable to assume that some maintenance costs are incurred as the result of operating the resource, even if such costs are not incurred immediately at the time of production," the commission said in its 2019 order, cited in the recent finding. ■

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PJM News

FERC Approves Removal of RTO Adder for AEP Ohio Cos.

FERC on Thursday approved revised rate schedules for two American Electric Power affiliates in Ohio to remove their RTO participation adders (*ER23-855*).

The order stems from a complaint filed last year by the Ohio Consumers' Counsel (OCC) arguing that because state law mandates that transmission owners in the state participate in an RTO, the utilities should not be eligible for the adder. The commission agreed in December, requiring AEP to make a compliance filing recalculating its returns on equity for the affiliates without the RTO adder. (See *FERC Orders Two Ohio Utilities Ineligible for RTO Adder*.)

Under the new language, AEP affiliates Ohio Power and AEP Ohio Transmission would lower their ROE from 10.35% to 9.85% under the filing and revise the PJM tariff to specify that the adder does not apply to those companies.

The commission also approved a proposal in AEP's filing to add language to the tariff stating that the companies have the right to receive refunds should federal courts invalidate the Ohio law, noting that there are pending lawsuits challenging the legislation on the grounds that it may pre-empt the Federal Power Act.

The OCC protested the filing, arguing that the notice provision asserting the right to collect refunds should not be approved, arguing it is out of scope, premature, and a violation of the filed-rate doctrine and rule against retroactive ratemaking.

| Shutterstock

AEP countered that the provision does not violate the filed-rate doctrine because it provides notice of a potential future rate change, which has been upheld by past court rulings. The commission agreed.

"If the commission's determination in the December order is overturned, the inclusion of the notice provision provides sufficient notice under the filed-rate doctrine to permit Ohio Power and AEP Ohio Transmission to surcharge customers," FERC wrote. ■

— Devin Leith-Yessian

Mid-Atlantic news from our other channels

Jersey City Unveils New EVs, Looks to Double Number of Charging Points — NetZero Insider

NJ Backs Studies of OSW Impact on Marine Life — NetZero Insider

NJ's 3-year Energy Efficiency Plan Faces Scrutiny — NetZero Insider

County Contests Tx Easement for NJ's 1st OSW Project — NetZero Insider

Developer Abandons Plans for 1,240 MW Gas Generator in Pennsylvania — NetZero Insider

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PJM News

PJM MRC Preview

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

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

Consent Agenda (9:05-9:15)

B. The committee will be asked to endorse proposed *revisions* to Manuals 1, 13 and 36 associated with future energy management system (EMS) updates and to meet NERC certification requirements.

Endorsements (9:15-10:50)

3. Manual 11 Revisions (9:15-9:40)

PJM's Joey Tutino will present proposed *revisions* to Manual 11: Energy & Ancillary Services Market Operations as part of a periodic review. The committee will be asked to endorse the revisions.

4. Renewable Dispatch (9:40-10:05)

PJM's Darrell Frogg will review a *proposal* on renewable dispatch, which aims to increase visibility on what the relevant resources can be dispatched down to. (See "PJM, Monitor Present Renewable Dispatch Proposal," *PJM MRC/MC Briefs: March. 22, 2023*.)

Issue Tracking: *Renewable Dispatch*

5. Capacity Performance (CP) Penalties (10:05-10:50)

A. Tom Hoatson of LS Power will present a *problem statement*, *issue charge* and *solution* that would modify when generators are subject to Capacity Performance penalties and how much they could owe.

B. Lynn Horning of American Municipal Power will present an *alternate solution* that would use the locational deliverability area clearing price under the Base Residual Auction to calculate penalties in lieu of the net cost of new entry.

C. Independent Market Monitor Joseph Bowring will present an alternate *issue charge* and *solution* that would link penalties to BRA clearing prices. ■

— Devin Leith-Yessian

SPP News

FERC Rejects SPP Self-funding Proposal for TOs

By Tom Kleckner

FERC this month rejected SPP tariff revisions that would help transmission owners continue to self-fund network upgrades to interconnect generators (*ER22-2968*).

The commission found in a 3-1 decision on April 14 that SPP had not demonstrated that its proposed *pro forma* facilities service agreement and associated tariff revisions were just and reasonable and not unduly discriminatory or preferential (ER22-2968).

The grid operator sought approval of a proposal to allow TOs to self-fund the upgrades and recover their costs and a return on investment from an interconnection customer.

American Clean Power Association, Advanced Power Alliance, the Solar Energy Industries Association, the Natural Resources Defense Council and the Sustainable FERC Project all intervened against the revisions. They said the self-funding would heap costs on generation developers if they didn't pay for the upgrades themselves.

FERC said SPP's proposal ran counter to *Order 2003*, which established standard interconnection procedures to limit opportunities for transmission providers to favor their own generation and facilitate market entry for generation competitors by reducing interconnection costs and time.

The commission said the revisions could lead to "greater uncertainty" for interconnection customers that might not elect to a TO's initial funding for upgrades, but then reverse course near the study process completion. It agreed with the clean energy advocates' argument that such circumstances could lead to late-stage withdrawals and delays in administering the generator interconnection queue, further undermining Order 2003's goals.

SPP and Xcel Energy subsidiary Southwestern Public Service contended that a non-binding indication provides an interconnection customer advance notice that a TO intends to self-fund prior to negotiation of generator interconnection. They also noted that FERC approved MISO's request to require TOs to make binding self-funding decisions before GIA negotiations begin.

FERC disagreed, saying the non-binding self-funding election means a TO can make a choice when the study process begins and then do the opposite. The commissioners said they accepted MISO's revisions to add deadlines by which TOs must make both non-binding and binding elections before the GIA negotiations. They said SPP's proposal includes only the non-binding indication provision.

"Having more information earlier is beneficial *not* harmful," the commission wrote. "By denying an earlier indication of the transmission owner's potential election, interconnection customers will be denied access to information at an earlier stage under the tariff. That denial of information actually creates uncertainty; it does not protect against it."

Commission Nixes PRM Waivers

The commission last week also rejected SPP tariff revisions that would allow load-responsible entities (LREs) to obtain two-year exemptions from deficiency payments assessed for not meeting the grid operator's new resource adequacy requirement, finding the grid operator had not demonstrated the proposal was just and reasonable (*ER23-636*).

The commission on April 17 found the RTO's proposal would undermine the structure of deficiency payments, set out in a 2018 filing to establish the resource adequacy requirement. LREs unable to meet the requirement are subject to a deficiency payment equal to the payment amount multiplied by the cost of new entry and a multiplication factor of the footprint's excess capacity relative to the planning reserve margin (PRM).

"The complete elimination of the deficiency payment, even under the criteria of the proposed exemption process, removes the incentive for LREs to procure the capacity needed to collectively ensure that the SPP footprint maintains resource adequacy," the commission wrote.

FERC has said SPP's proposed deficiency payment "provides a signal to LREs to plan ahead to satisfy the [resource adequacy requirement]."

The commission found that while the proposed exemption is limited to two hours each time the grid operator increases the PRM, LREs would be able to seek the exemption each time there is an increase. It said that, were SPP to make consecutive increases, deficient LREs with exemptions wouldn't be required to meet their resource adequacy obligations for an extended time.

FERC also said the proposed tariff language is not clear as to how the proposed exemption process would work.

SPP last year increased the PRM to 15% from 12% for the 2023 season and filed the proposed exemption language. (See *SPP Board Bypasses Stakeholders on PRM Obligation Exemptions*.)

Evergy's Denise Buffington, who warned last October that the proposal would fail at FERC, suggested SPP's future tariff revisions should allow more time for compliance.

"It takes time to get steel in the ground, and if SPP continues to increase the performance or planning reserve margin on an annual basis, we're never going to be able to meet it," she said during a Resource and Energy Adequacy Leadership Team meeting Thursday. "When we think about setting out new requirements, we have to do them far enough in the future so that load-responsible entities can actually comply." ■

FERC has rejected SPP tariff revisions that would help transmission owners continue to self-fund network upgrades to interconnect generation. | *General Electric*

SPP News

FERC Denies Rehearing of Tenaska Curtailment Complaint

Commission also Rules on SPP FSAs

By Tom Kleckner

FERC on Thursday denied Tenaska's rehearing request over the alleged curtailment of its Clear Creek Wind Farm, maintaining that the company did not provide sufficient evidence (*EL22-59*).

Tenaska alleged that SPP, MISO, Associated Electric Cooperative Inc. (AECI) and the Tennessee Valley Authority adopted operating guides that resulted in unduly discriminatory curtailment of the Missouri wind farm it owns and operates. FERC disagreed, denying the complaint in December. (See *FERC Denies Tenaska's Complaints over Wind Curtailments*.)

The developer argued that FERC lacked substantial evidence to conclude that the operating guides limit the wind farm pending network upgrades assigned to Tenaska. It said the commission's conclusion was a "*post hoc* rationalization" and asserted that the order was an unexplained departure from precedent, relying on SPP and AECI documents as supporting the operating guides.

FERC said that it was not persuaded by Tenaska's argument, saying it was up to the complainant to present evidence supporting its assertions that the curtailments were unjust and unreasonable, unduly discriminatory or preferential, or inconsistent with the operators' tariffs. It pointed out that SPP and AECI said the curtailments were consistent with congestion requiring network upgrades assigned to Tenaska and the reason behind the project's limited operation status.

Tenaska's argument that the original order was inconsistent with precedent was "misplaced," the commission said. It said Tenaska's reliance on *Iberdrola v. Bonneville* overlooked the fact that the curtailed wind generators in that proceeding "were not responsible for incomplete network upgrades."

The commission found the project's curtailments after the required upgrades were identified in an SPP restudy were consistent with the RTO's generator interconnection procedure (GIP) and not unduly discriminatory.

"Adopting Tenaska's position would be inconsistent with the structure set forth in the text of SPP's GIP … and the purposes underlying that provision," FERC wrote.

The commission said if Tenaska believed that FERC erred because there were curtailments prior to a subsequent restudy that was not justified, it was incumbent on the developer to identify the relevant curtailments and demonstrate that alleged error. "It did not do so," the commission said.

Facilities Agreements Approved, Rejected

The commission on April 18 accepted SPP's unexecuted facilities service agreement (FSA) that the grid operator filed for a 102.6-MW wind farm in West Texas (*ER23-342*).

SPP, the transmission provider, filed the generator interconnection agreement last year on behalf of transmission owner Southwestern Public Service and interconnection customer Panhandle Solar.

Panhandle protested the GIA's 20-year term, saying it had proposed a three-year term that SPP rejected. It said that when an interconnection customer is willing to pay the money back faster, a longer term imposes added and unwanted financing costs that are not just and reasonable and merely serve to enrich the interconnecting TO's shareholders. Panhandle said the 20-year FSA would double the overall amount it paid for the network upgrades under the GIA.

The commission found that the 20-year term was consistent with MISO's *pro forma* FSA that FERC had previously approved as just and reasonable. It said that 20 years allow SPS to recover its return of and on capital invested in network upgrades based on the term over which the utility will likely provide interconnection service to Panhandle. It also gives Panhandle a shorter period to pay depreciation expenses than the recovery period based on useful service life, FERC said.

"We find it reasonable to expect interconnection service under the Panhandle GIA to match or exceed 20 years," the commission said.

FERC noted that Panhandle acknowledged that the "initial terms of GIAs often do extend 20 years … based on how long the generating facility in question is expected to operate." They pointed out that Panhandle had not expressed any intention to take interconnection service only over the GIA's initial 10-year term.

FERC also on April 18 rejected an FSA filed by SPP last year, this one for TO ITC Great Plains and interconnection customer Pixley Solar Energy (*ER23-155*).

The Clear Creek Wind Project | *Mortensen Wind Energy Group*

The commission found the agreement to be unjust, unreasonable and unduly discriminatory or preferential. It disagreed with ITC's assertion that the *Mobile-Sierra* doctrine, which mandates respect for private contracts by shielding them from regulatory interference except when necessary in the public interest, applied to the FSA as executed.

FERC said the ordinary just-and-reasonable standard applies when the parties "explicitly reserve their rights to seek modifications to their contracts," indicating that they "specifically negotiated and contemplated that their contracts could be modified" based upon the ordinary J&R standard.

"Those findings apply here," the commission said, pointing to the FSA's language that states "nothing in this service agreement shall limit the rights of the parties or of FERC under Sections 205 and 206 of the [Federal Power Act] and FERC's rules and regulations thereunder."

The commission also said ITC's recovery of additional expenses that included an allocated portion of its operations and maintenance expenses was not justified and that certain references and calculations in the formula rate lacked transparency and were inaccurate.

FERC rejected the FSA without prejudice, offering guidance to SPP and ITC in refiling the agreement.

Commissioner James Danly dissented, saying the other three commissioners failed to recognize and address the fact that under FERC's "fairly recent precedent, system protection facilities may be network upgrades" in the SPP footprint. ■

SPP News

SPP MPEC Briefs

RTO, Stakeholders Join Race with CAISO for Western Market

WESTMINSTER, Colo. — SPP Markets+ stakeholders last week kicked off the development phase of the grid operator's proposed "RTO-light" service offering in the West, heating up the race with CAISO to create a regional market.

Meeting for the first time, the *Markets+ Participants Executive Committee* (MPEC), comprised of potential participants and stakeholders that have financially committed to drafting the market protocols, tariff and governing documents, agreed to accelerate the timeline to file the tariff at FERC.

MPEC now plans to make the filing by December or early next year. CAISO plans to file a tariff for its competing Extended Day-ahead Market (EDAM) before the year is up.

Laura Trolese, The Energy Authority | *© RTO Insider LLC*

The Energy Authority's Laura Trolese, the MPEC's newly elected chair, said speed is of the essence because some Western entities need to decide between the two markets within a year.

"They need an alternative to evaluate against in order to be able to make that decision," she told *RTO Insider*. "While it may seem that we're racing through this, we have been working on developing a market now for years, and we've had these same discussions. Yes, there are some new things, but we've had the same discussions and been working on putting a market together for four years together with some of the same faces in these previous efforts, some of the same faces that have been working through the EDAM process.

"We have a lot to draw from and to work from. It's not starting from scratch and reinventing the wheel," Trolese said.

The decision was just one of many stakeholders made during the two-day meeting. The MPEC also:

- approved extending the participant funding agreement deadline to May 1, allowing as many as four interested parties to formally commit to Markets+'s development;
- endorsed the first development phase's scope of activities, tasks and deliverables;
- agreed with SPP staff's proposal to allow entities to begin participating in Markets+ once FERC approves the tariff next year, even though some day-ahead functions may be unavailable; and
- approved stakeholder group charters, leadership and rosters.

SPP Vice President Antoine Lucas opens the Markets+ Participants Executive Committee meeting. | *© RTO Insider LLC*

The MPEC will oversee four working groups (design, seams, transmission, and operations and reliability) and five task forces that are expected to meet on a three-week cadence. Committee members amended their charters to allow the MPEC to reevaluate membership and voting once new funding agreements are executed.

The committee will meet in-person on a quarterly basis, with briefings to occur virtually as needed. The three-person *Interim Markets+ Independent Panel* (IMIP) provides final decision-making authority and a link to SPP's Board of Directors. The panel, all SPP directors, plans to hold its meetings after the MPEC's.

"The stakeholder process and the governance process that this group is engaged in is an ideal fit for the Western mindset," said IMIP member John Cupparo, a Colorado native who professes a "don't-fence-me-in" mindset. "It's both challenging and rewarding. It will be some ups and downs along the way, but in the end, I think we're getting a great product."

"For those of you who haven't seen it, it's really an interesting process," Eric Blank, chair of both the Colorado Public Utilities Commission and the *Markets+ State Committee*, told his committee Friday. "I really encourage you to watch, even independent of the substance. RTOS in the East that are staff-driven. This is really stakeholder-driven, and people just vote. It's really unique."

It's that stakeholder-driven culture that SPP hopes will be the difference for Markets+.

"I've spent an awful lot of time in rooms like this talking about market evolution in the West … but I do believe that this is one that really is going to succeed," said IMIP Chair Steve Wright, who previously has headed both the Bonneville Power Administration and Chelan (Washington) Public Utility District.

He pointed to the SPP-administered *Western Resource Adequacy Program*, the West's first regional reliability planning and compliance program, as laying a "great foundation" in the West.

"Now we're in a place where we actually had something that really works and we can build even more from that. This governance model, as applied to the West, can produce a market design for the West and by the West. SPP's role here is not to make the decisions. Our role here is to facilitate and assist you in coming up with a market design that you want."

SPP News

The IMIP's first voting item Wednesday was to approve the MPEC's endorsement of a change to its voting structure that gives the independent sector a greater voice.

'Frankensteining' the Markets+ Tariff

The Markets+ Design Working Group will do much of the heavy lifting over the next few months, working with SPP staff to draft the tariff that will eventually be filed at FERC.

Staff said they have already "Frankensteined" together the best elements of markets previously approved by FERC into boilerplate language. Stakeholder groups will rework the basic tariff language to better fit *Markets+'s unique design*, with the MDWG reviewing their work.

"I can't wait for the first 'Mad Wag'!" SPP's Chris Nolen said, sounding out the working group's acronym.

"We started with a blank slate. We're not bolting Markets+ onto an existing code … it has to fit comfortably and exist on its own. We drafted it that way," Nolen, a senior attorney and tariff expert, said. "We borrowed pieces that worked well for many other tariffs. It gives us an easier process to justify those scans at FERC. To that end, when we draft this tariff, it should be, at least as I see it, the best tariff yet of the best ones."

MPEC Leadership Promises Collaboration

Trolese's first order of business after being elected chair of the MPEC? Adjourning a lengthy discussion for lunch, a move that was greeted with rousing cheers.

Both Trolese and Vice Chair Brian Cole, with Arizona Public Service, said they plan to ensure the committee collaborates on recommendations that benefit the region as a whole.

"My goal is to find ways for all of us to come together, to make decisions together," Cole told MPEC members. "I don't want this to sound like a campaign speech, but you'll have that from me, without exception."

Trolese said her role is to facilitate decision making and ensure everyone's voice is heard and "that they're given the opportunity to be able to express their concerns, but also to make sure that we're sticking to the timeline that we committed to and we voted on and that we're able to deliver what we set out to deliver, which is to get this tariff up and filed at FERC by Q1 of 2024.

"I think it will be a challenge to balance speed and inclusion, but I think it's something that we're going have to do in order to get this thing up and going," Trolese said.

Director of Western markets and strategy for TEA, Trolese has spent the past 16 years in Washington with either Bonneville Power Administration or the Public Generating Pool. Much of that time has been spent on market development in the West. Efforts to create an RTO go back to 1995, she said.

"Our success in the West has been incremental," Trolese said. "The Pacific Northwest has some of the lowest rates in the country, so the value proposition of lowering rates can be a challenging one, when they have some of the lowest-cost power, they have pretty clean power, and they have the lowest rates."

MSC Gets Down to Business

The Markets+ State Committee wasted little time in getting started, holding a conference call Friday to discuss the MPEC's actions and the MSC's next steps.

Blank encouraged MPEC members to contact the group and its support staff with their ideas and recommendations for the development of Markets+.

"The goal of the MSC is to become informed as the process evolves, participate, get our questions asked and answered, get our concerns raised and addressed, and try and limit what happens on the back end," Blank said.

The MSC is comprised of *regulators from nine Western states*. However, members amended the group's charter Friday to allow participation from other Western states and Canadian provinces. The California Public Utilities Commission has asked to join the MSC and British Columbia regulators have also expressed interest.

The *Western Interstate Energy Board (WIEB)*, comprised of 11 Western states and two western Canadian provinces, is serving as the MSC's support staff. The WIEB has hired as its support *AESL Consulting*, which provides strategic regulatory and public policy support to public utilities, led by founder Ed Garvey and former MISO executive and Minnesota commissioner David Boyd.

"We have had nothing but offers of support to the extent we need it from SPP. They've been very cordial," Boyd told the MSC. "I won't put words in their mouth, but I think they recognize the value that regulators bring or have brought to their markets and therefore, the need to do a lot of work on the front end to expedite implementation on the back end. To the extent we need resources, I'm quite confident SPP will be supportive."

SPP staff already has amended the stakeholder groups' charters to allow MSC members to participate. They have advisory roles on the working groups and voting roles on the task forces. The WEIB has recommended assigning three commissioners to relevant groups; the board and its consultants will staff each stakeholder group.

The MSC plans to hold another call Friday to vote on the charter amendment and begin making stakeholder group appointments. It will begin its normal cadence of meetings in May. ■

— Tom Kleckner

SPP's Jim Gonzalez (left), Colorado PUC Chair Eric Blank listen to stakeholders' discussion. | *© RTO Insider LLC*

Company Briefs

EPE on Ballot to Become City-owned Utility

One measure on the El Paso election ballot for May would see the city "employ all available efforts to convert El Paso Electric to municipal ownership."

El Paso Electric is owned by the Infrastructure Investments Fund and managed by J.P. Morgan Chase; it has customers in Texas and New Mexico. While the city would probably have to pay billions to acquire El Paso Electric's assets, doing so could create a new revenue source for the city and give residents tighter control of the utility.

EPE said it is opposed to any efforts to bring it under the city's control, saying converting the utility would raise complex legal and regulatory questions over how to divide its assets and what investments the city would have to make. Turning EPE into a municipal utility would produce two utilities: one to serve residents within city limits and another to serve customers in New Mexico and Texas.

More: *El Paso Matters*

Lordstown Motors Resumes Production, Gets Delisting Notice

Lordstown Motors last week announced it has resumed production of its all-electric Endurance pickup trucks at a "very slow pace" after a pause of more than two months.

In February, Lordstown issued a recall of the Endurance to address issues related to its propulsion system. According to filings, the company had already halted production of the truck before the first defects were reported in January. The recall affected 19 vehicles. A second recall was announced March 6 to address a braking system component in seven vehicles.

Last week, Lordstown announced it had received a delisting notice from Nasdaq and is evaluating actions, including a reverse stock split to meet the minimum bid price requirement set by the exchange. The company received the notice because the closing bid price for its class A common stock fell below the minimum required price of $1 per share for 30 straight sessions.

More: *The Business Journal*, *Reuters*

Tesla's Profits Drop Sharply in Q1

Tesla's profits fell sharply in the first quarter of the year after it cut the prices of its EVs. It made $2.5 billion in the first three months — a drop from $3.7 billion in the fourth quarter of 2022.

Profits also dropped in comparison to the $3.3 billion the company made in the first quarter of 2022.

The average selling price for Tesla's vehicles in the first quarter was nearly $46,000, down from $51,400 in the last quarter of 2022. But despite that 11% decline, vehicle deliveries were only 4% higher.

More: *The New York Times*

Federal Briefs

Biden to Veto Legislation to Block Solar Tariff Waivers

President Biden said he will veto any congressional efforts to overturn his solar tariff waiver for four Southeast Asian nations for two years.

In June, Biden waived tariffs on solar panels from Cambodia, Malaysia, Thailand and Vietnam in an effort to create a "bridge" while U.S. manufacturing ramps up to supply domestic projects. The four countries make up about 80% of U.S. panel supplies.

Last week a House committee voted in favor of restoring the tariffs on the panels from the countries, reversing Biden's suspension. That legislation, which both Democrats and Republicans support, is expected to come up for a full vote in the House as soon as this week.

More: *Reuters*

Supreme Court Rebuffs Exxon, Chevron Appeals in Climate Cases

The U.S. Supreme Court this week declined to hear bids by Exxon Mobil, Suncor Energy, Chevron and others to move lawsuits filed by state and local governments accusing the oil companies of worsening climate change out of state courts and into federal courts.

The justices voted 7-1 to turn away five appeals by the companies of lower court decisions that determined that the lawsuits belonged in state courts in Rhode Island, California, Colorado, Hawaii and Maryland.

More: *Reuters*

Study: EPA Underestimating Methane Emissions from Oil, Gas

A study published in the *Proceedings of the National Academy of Sciences* claims methane pollution from the U.S. oil and gas industry was 70% higher than the EPA's estimates between 2010 and 2019.

The study suggests the federal government's current system for detecting methane leaks from fossil fuel pipes, wells and compressors is inadequate. Several recent studies have shown similar results, and scientists now say the EPA needs to leverage new technology to get a fuller picture of how much of the greenhouse gas is escaping into the atmosphere. However, an EPA spokesperson noted that another recent study found that 2019 levels were on par with the agency's estimates for that year.

Methane, the main component of natural gas and a byproduct of fossil fuel drilling, has more than 80 times the warming power of carbon dioxide in its first two decades in the atmosphere.

More: *CNN*

TVA Fuel Costs on the Rise Again

The Tennessee Valley Authority last week announced it is raising its monthly fuel cost

adjustment again in May because of higher coal costs and anticipated increases in power consumption.

Although TVA has not raised its base electric rates since 2019, the utility adjusts part of its prices each month to reflect changes in the price of coal, natural gas and purchased power used to supply its seven-state region.

TVA spokesperson Scott Brooks said that the May fuel rate is 32% higher than the three-year average.

More: *Chattanooga Times Free Press*

State Briefs

FLORIDA

Gainesville Approves Archer Solar Plant

Gainesville city commissioners last week unanimously approved a site for the Sand Bluff Solar Project.

The commission approved staff's recommendation to amend and approve the solar plant contract with Origius and keep future projects away from historically black neighborhoods in Alachua County.

More: *WCJB*

GEORGIA

Georgia Power, PSC Agree on Fuel Costs Rate Hike

Georgia Power and the Public Service Commission's Public Interest Advocacy staff last week reached an agreement that will result in a slight reduction in the utility's request to recover $2.1 billion in fuel costs from customers.

If the PSC approves the agreement, Georgia Power would trim $7 million off its recovery request, while the average customer would see an increase of $17 on their monthly bills. The commission approved a $1.8 billion rate increase for the utility in December, which raised the average monthly bill by $3.60 on Jan. 1. The utility then filed for the fuel costs recovery in February.

The PSC will vote on the plan on May 16.

More: *The Current*

IDAHO

Idaho Power Files for Power Cost Increase

Idaho Power last week filed a power cost adjustment with the Public Utilities Commission that calls for a $200 million price increase because of higher power costs related to natural gas and market prices, lower than expected hydro generation and a limited coal supply.

The money collected would be used solely to recover expenses associated with annual fluctuations in power supply costs. The PCA requests a monthly bill increase of $12.72 for the average residential customer.

If approved, the rate changes will take effect June 1.

More: *Hydro Review*

ILLINOIS

Plan to Lift Moratorium on Nuclear Construction Moves to House Floor

The House Public Utilities Committee last week voted 20-1 to lift a 1987 ban on the construction of new nuclear plants.

The bill comes as state lawmakers have been urged to bring more nuclear plants online to replace closing coal and natural gas plants.

The bill now moves to the House floor for further consideration. If passed, the legislation will go to Gov. JB Pritzker's desk.

More: *WAND*

INDIANA

Senate Defeats Amendment to Coal Ash Restrictions

The Senate last week voted 28-20 to defeat an amendment to House Bill 1623 that would have addressed procedural changes regarding the disposal of coal ash.

The proposed amendment would have allowed the state to add restrictions to a planned coal ash permit program that are more stringent than or not included in a federal coal ash disposal rule. States have been allowed to establish their own coal ash permitting programs since 2016, though the programs must be at least "as protective as" the federal coal combustion residual rule. States are also allowed to enact stricter regulations if they choose to.

The Senate will hold its final vote on HB 1623 next week.

More: *Indiana Environmental Reporter*

Senate Passes Bill Giving Utilities First Rights on Interstate Projects

The Senate last week voted 32-17 to pass a bill that would give state utilities dibs on building, owning and operating power lines that cross state borders.

Proponents of the bill say it will let utilities do more of these projects and will keep costs in check for residents; they also say fewer bids mean the projects will get done more quickly. However, opponents say the idea that giving utilities dibs would lower costs doesn't make any sense, as the best way to do that is through competition.

The bill now goes back to the House to consider changes.

More: *WFYI*

IOWA

Ames Unveils Climate Action Plan

The Ames City Council last week was presented a draft of a Climate Action Plan that outlined expenditures from 2023 to 2050 for the $3.2 billion plan.

The plan includes six moves to reduce emissions: heat pumps and retrofits; renewable energy generation; net-zero new construction; reducing vehicle emissions; increasing active transportation and transit use; and reducing waste emissions.

The council will revisit the plan in late May or early June.

More: *Iowa State Daily*

Senate Advances Utility Board Picks

The Senate Commerce Committee last week confirmed Erik Helland and Sarah Martz to the Utility Board.

The appointments will fill two vacancies: Richard Lozier's term ends April 30; current Chair Geri Huser will also step down at the end of the month.

The duo will need to pass a two-thirds vote in the Senate to be confirmed to the panel.

More: *The Gazette*

LOUISIANA

Entergy New Orleans Proposes $1B Storm-hardening Plan

Entergy New Orleans last week proposed a $1 billion plan to the New Orleans City Council to harden its grid over the next 10 years.

The request is for the first of two five-year phases that will begin with approximately $559 million of investments with a focus on hardening projects, including replacing more than 12,000 distribution poles across New Orleans to improve wind resistance up to 140 mph and the undergrounding of more than two miles of lines.

Projected bill impacts will increase year over year, with an expected monthly bill impact on an average residential customer of 20 cents in 2024 and up to $12 by 2028.

Entergy requested a decision from the city council by the end of the year.

More: *Daily Energy Insider*, *Entergy*, *Nola.com*

MINNESOTA

House Passes Environment, Natural Resources, Climate and Energy Bill

The state House of Representatives last week passed the 2023 Environment, Natural Resources, Climate, and Energy Budget bill, which will direct $670 million in new funding toward multiple state agencies.

The "environment and natural resources" portion of the bill includes $93 million for replanting trees and responding to emerald ash borer, $6.6 million to address aquatic invasive species, and a package to slow the spread of chronic wasting disease in wild and farmed deer populations.

The "climate and energy" provisions include $348 million in funding to lower energy costs, create more clean energy jobs, and address and combat climate change. It holds almost $50 million in weatherization funding and $65 million in solar and storage technology investments.

The bill now heads to the Senate.

More: *KNSI*

NORTH CAROLINA

National Guardsman Accused in Neo-Nazi Grid Plot Pleads Guilty

Joseph Maurino, one of several men charged for an alleged neo-Nazi plot to attack substations, plead guilty on April 11.

Court records indicate Maurino entered a guilty plea to one count of conspiracy to manufacture firearms and ship interstate and pleaded not guilty to a count of destruction of an energy facility. Maurino was indicted in 2021 and accused of conspiring to supply guns to Paul Kryscuk, Liam Collins and Jordan Duncan, who were charged in October 2020 and accused of plotting to attack the power grid.

Maurino's sentencing is set for July 11.

More: *WGHP*

OHIO

Power Siting Board OKs Palomino Solar Project

The Power Siting Board last week voted 8-1 to issue a certificate of environmental compatibility and public need for the Palomino Solar project in Dodson and Union Townships.

The project is expected to be located across 2,700 acres of private land, with an anticipated impacted area of 1,410 acres, according to the Public Utilities Commission.

Construction is slated to begin in 2024 and is expected to be completed by mid-2025.

More: *The Highland County Press*

WISCONSIN

Assembly Passes Bills to Block Gov't from Curbing Fossil Fuel Use

The state Assembly last week passed two bills that would bar the state and local governments from banning fossil-fuel powered tools, appliances or vehicles.

One bill states that no state agency or local unit of government "may restrict the use or sale of a device based on the energy source that is used to power the device or that is consumed by the device." A second similarly bars state or local governments from restricting "the use or sale of motor vehicles based on the energy source used to power the motor vehicle, including use for propulsion or use for powering other functions of the motor vehicle." The bills passed by votes of 62-35 and 63-35, respectively. Each bill also has a state Senate counterpart.

More: *Wisconsin Examiner*

Evers Signs Order Creating Green Ribbon Commission

Gov. **Tony Evers** last week signed an executive order creating the Green Ribbon Commission on Clean Energy and Environmental Innovation to help create the state's first Green Innovation Fund.

The fund will leverage public and private financing to invest in projects that provide environmental and clean energy solutions, reduce pollution, lower energy costs and expand access to renewable energy.

The commission will consist of members appointed by the governor, including representatives from the Department of Administration and the Economic Development Corporation. The fund will be administered by the EDC in partnership with the DOA.

More: *WSAW*

Second Saratoga Solar Project Approved

The Public Service Commission last week approved the 150-MW Saratoga Solar Project.

It is the second solar project in Saratoga and will equal the capacity of the now-operating Wood County Solar Project.

Construction is expected to begin this summer and be completed by the end of 2024.

More: *Wisconsin Rapids Tribune*

WYOMING

Supreme Court Upholds Wind Farm

The state Supreme Court last week ruled in favor of the 120-turbine Rail Tie Wind Project.

The court said Albany County's board of commissioners were justified in authorizing the 500-MW project and upheld an earlier district court loss for a pair of lawsuits representing almost 50 local landowners opposed to the farm. Both challenges argued that the permitting process was incomplete and that commissioners erred by approving a special-use permit.

The court found that the commissioners fulfilled everything the law required of them and said the permit approval "was not arbitrary and capricious and was not a taking of private property."

More: *Casper Star-Tribune*