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***ERO INSIDER* SPECIAL REPORT**

Bid-rigging Allegation Clouds Avangrid Bid for PNM

Utility Accuses Former Cybersecurity Contractor of Extortion

By Rich Heidorn Jr.

Avangrid's proposed $8.3 billion acquisition of PNM Resources appeared in peril last week after a former cybersecurity contractor alleged that the company conspired with suppliers to buy "tens of millions" in overpriced and unnecessary security equipment and services to boost profits. The company may also face increased scrutiny from regulators in New York and New England as a result of the allegations.

Security Limits Inc. CEO Paulo Silva | *Paulo Silva via LinkedIn*

In a Nov. 29 *lawsuit* filed in the U.S. District Court for the Southern District of New York, *Security Limits Inc.* (SLI), of Jessup, Pa., and CEO Paulo Silva accused Avangrid and its Spain-based parent Iberdrola, of a "brazen racketeering scheme, replete with bid-rigging, accounting manipulation [and] warehouses built solely to house mountains of unused equipment procured under bogus pretenses." SLI is seeking more than $110 million in damages from the utility and others that it says stole SLI's proprietary business secrets (Case No. 21-CV-1012).

Avangrid, which denied the allegations, responded with its own suit Saturday accusing Silva of extortion, saying he made the allegations after the utility refused to rehire his company. Avangrid's *suit*, filed in Santa Fe

Continued on page 5

CPUC Orders Procuring 3 GW of Capacity

Commission Approves Plans to Prevent Shortfalls in Extreme Summer Conditions

By Hudson Sangree

The California Public Utilities Commission on Thursday adopted measures aimed at securing up to 3 GW of additional capacity through supply- and demand-side programs to prevent shortages in extreme heat waves in the summers of 2022 and 2023.

The CPUC's procurement order included increased battery storage | *PG&E*

The measures include ordering the state's three big investor-owned utilities — Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric — to accelerate procurement of battery storage and to increase production from existing natural gas plants, as well as increasing payments to demand response customers.

The CPUC projected shortfalls of 2 to 3 GW during the next two summers, but PG&E, SCE and SDG&E have already procured 1 GW in response to earlier commission decisions, President Marybel Batjer said.

"While the gap is large, I want to be clear that there is already significant procurement that can be used toward this need," Batjer said.

Measures *approved* in three decisions Thursday

Continued on page 14

FERC Accepts CAISO Hybrid Resource Changes (p.13)

Texas PUC Pushes 44% Reduction in ERCOT Offer Cap

By Tom Kleckner

The Texas Public Utility Commission's four members reached consensus during an open meeting Nov. 30 on $5,000 as the operating reserve demand curve's (ORDC) top-line number, a 44% reduction from the current $9,000 (*52631*).

The ORDC is designed to accurately reflect shortage conditions by increasing power prices through an adder when operating reserves dip below 2 GW. It's also seen as a price signal to investors that additional generation is needed in the market.

Commissioner Will McAdams offered up

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2 More Directors Appointed to ERCOT Board (p.18)

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In this week's issue

Green Hydrogen Coalition Annual Fall Conference

'Ecosystems' Needed to Drive Green Hydrogen Growth

By Robert Mullin

The widespread adoption of clean hydrogen in North America will depend on the construction of "ecosystems" that span economic sectors, state lines and national boundaries, industry supporters said last week at the Green Hydrogen Coalition's virtual annual conference.

"A green hydrogen economy doesn't exist in any one city or state; it is a regional and national solution," Janice Lin, GHC founder and president, said Wednesday.

In wrapping up the two-day conference, Lin said one of her key takeaways was the need for creating hydrogen "hubs" internationally to lay the groundwork for expanded adoption of green hydrogen as a fuel source across multiple economic sectors.

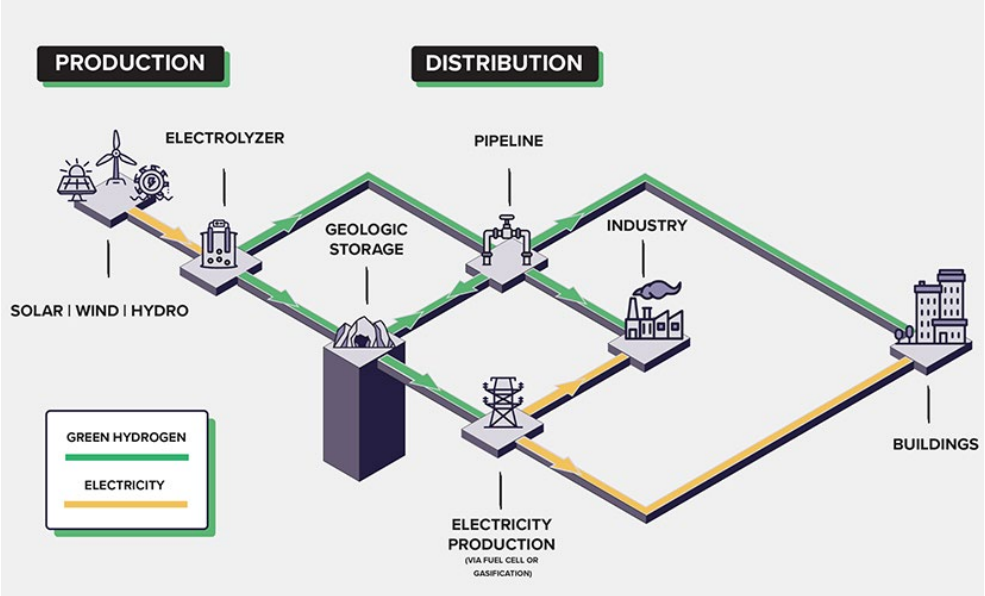
In the U.S., the $1.2 trillion infrastructure bill passed by Congress last month provides $8 billion for development of four such hubs in the country, as well as $1 billion toward domestic production of the electrolyzers needed to produce hydrogen, part of the Department of Energy's Hydrogen Energy Earthshot initiative. (See *Granholm Announces R&D into Green Hydrogen as 1st 'Energy Earthshot.'*)

Sunita Satyapal, director of DOE's Hydrogen and Fuel Cell Technologies Office, reminded conference participants of the initiative's "1-1-1" objective: "One dollar for 1 kg of clean hydrogen in one decade."

Through an effort that predates the infrastructure bill, GHC has been spearheading development of a green hydrogen hub centered in Southern California. The goal of the HyDeal Los Angeles initiative is to deliver green hydrogen for the Los Angeles Basin at $1.50/kg by 2030.

Lin said HyDeal LA was conceived in part to help combat the heavy air pollution that plagues the basin. The top five sources of smog in the region, she said, include ships, heavy-duty trucks, offroad equipment, aircraft and diesel locomotives, and much of that pollution emanates from activity related to the area's massive ports in Los Angeles, Long Beach and San Pedro Bay.

Green hydrogen could be a "key enabler" for improving the region's air quality, especially for residents living in the disadvantaged communities near the ports and along L.A.'s busy freeways, she said.



The production and distribution portions of a green hydrogen "ecosystem" | *Green Hydrogen Coalition*

"It's a scalable, commercially viable alternative, both as a direct fuel as hydrogen [and] as [an] energy ingredient in a synthetic fuel that can directly displace all fossil fuel use in and around the port," Lin said. "Nearer term, we can use green hydrogen to go after cargo-handling equipment [and] heavy-duty vehicles, and in the medium- to long-term — and we call that 2025 to 2030 — we can use green hydrogen to go after locomotives, oceangoing vessels and harbor craft."

Despite those objectives, Lin noted that HyDeal LA's initial foothold into a green hydrogen economy will take shape in the electricity sector, as the Los Angeles Department of Water and Power (LADWP) converts the massive coal-fired Intermountain Power Plant in Delta, Utah, into a natural gas-fired plant capable of burning 30% hydrogen when it opens in 2025. With ample transmission capacity to draw on surplus solar generation, the facility will also be capable of producing hydrogen on site — and able to store large volumes in nearby salt domes.

LADWP will also replace its gas-fired Scattergood plant in El Segundo, slated for closure by 2024, with a new plant capable of burning a gas-hydrogen fuel mixture. The utility owns other gas-fired facilities that could also be candidates for conversion.

"Repurposing these power plants, and converting them from natural gas to green hydrogen has immediate local air quality and health benefits," Lin said. "For starters, once power plants are converted to green hydrogen, their emissions are cut to zero for carbon dioxide, carbon monoxide, SO_x, volatile organic compounds and particulate matter. In the future, these plants won't be run as often because we'll have a whole portfolio of abundant different types of renewable resources, and so the frequency will go down tremendously. That means the NO_x emissions from the stack will also go down tremendously."

European Ambitions

HyDeal LA was inspired by the HyDeal Ambition consortium, a similar and more advanced effort unfolding in Europe. Speaking at the GHC conference, HyDeal Ambition founder Thierry LePercq (also a GHC board member) said the concept was the result of collaboration among industry players and governments.

"But first and foremost, what is fundamental in the HyDeal approach is that you bring upstream companies — that is solar developers and electrolyzer makers; you bring the midstream companies — mostly gas transmission and storage; and then you bring offtakers in industry, in energy and potentially other fields," he said.

LePercq said that as Germany ramps up its renewable capacity and works to phase out coal (by 2030) and natural gas from an electricity system that has already abandoned nuclear power, all dispatchable power serving the country will need to be "H_2-ready."

Green Hydrogen Coalition Annual Fall Conference

"What does that mean? It means that dispatchable power in Germany is going to be based on hydrogen. How many gigawatts of renewable energy [to produce the hydrogen] do you need to get there?" LePercq said.

The hydrogen hub intended to serve those needs will be based in an industrialized area of the northwestern Spanish province of Asturias. The renewables needed to produce the hydrogen will take the form of "captive" — or dedicated — solar resources that will generate low-cost electricity to power the electrolysis process.

LePercq said HyDeal Ambition is approaching its project with the idea of serving demand at scale, rather than serving a limited purpose.

"Because when you are a cement plant or fertilizer plant and steel plant, or a thermal power plant, you want very big volumes. You don't want a tiny project supplying a tiny bit of hydrogen produced locally at super high prices," he said. "And I must be frank with you: Until recently, in Europe, most of the projects that have been developed have been developed in what we call 'policy' hydrogen, small-scale hydrogen, which is not leaving too much, because small volumes, very high prices, [create a] need for very big subsidies."

The large scale and ready market will enable green hydrogen to quickly become cost-competitive with natural gas, LePercq explained.

Collaboration Across Sectors, Boundaries

Lin has a similarly expansive vision for the HyDeal LA hub, which would connect the L.A. Basin with the Desert Southwest to include LADWP's IPP project.

"Long term, we set out to make Los Angeles North America's first green hydrogen industrial hub at scale, the first to achieve truly 100% renewable electricity affordably and reliably; move to fuel refining and alternative synthetic fuels; provide green hydrogen and its derivatives for shipping [and] aviation [and] maybe someday fertilizer; [and] demonstrate green hydrogen flight," Lin said.

GHC is also talking with other governments — including Japan's — about exporting green hydrogen, she said.

"As we look at hydrogen as a whole, we really like the idea of this hub approach, because we really need to maximize the capacity factors of the electrolyzers that we're installing," said Peter Sawicki, regional director of sales and marketing at Mitsubishi Power Americas, which will supply the turbines for the IPP project. "And in order to do so, we have to really bring in other sectors, which utilize maybe not as much hydrogen [on a] per-unit basis, but also utilize that hydrogen around the clock."

Sawicki said LADWP and Mitsubishi are "blessed" with the massive storage capacity available at IPP, but for other regions he likes the idea of using pipelines to store hydrogen or move the fuel to and from storage fields.

"Mitsubishi is not going to be developing these pipelines throughout the United States. We're looking for really partners on that approach as we look to build out this hydrogen infrastructure as we move forward," he said.

Michael Healy, vice president of origination at 8minute Solar, said his company thinks the use of behind-the-meter solar is the most cost-effective way to produce clean hydrogen.

"It's not just as simple as hooking up a solar plant to an electrolyzer. There are all these components that go into it, and it will really drive down costs if they're integrated together in an efficient and optimal way," Healy said.

Andrew Hegewald, Utah-based gas development manager for Dominion Energy, said four elements need to be addressed in building a hydrogen ecosystem: production, transportation, distribution and consumption. Furthermore, each sector, such as transportation or power generation, will require its own ecosystem.

"Once you understand the landscape, then it's figuring out who would the partners be in building this ecosystem," he said.

Barbra Korol, executive director of Alberta's Department of Energy, noted that the Canadian province currently produces the equivalent of 24% of all hydrogen generated in the U.S., most of which is "gray" hydrogen produced from natural gas.

"Our ambition is to transition that gray production to blue hydrogen or ultra-low carbon — clean — hydrogen," Korol said.

Alberta has an abundance of natural gas for producing hydrogen, but the province is open to "other pathways," recognizing that its competitiveness will require reducing the carbon intensity of its hydrogen, she said. The province's hydrogen strategy, released last month, calls for clean hydrogen "integrated at scale" for use in domestic and export markets.

"It's very much a regional strategy that seeks to collaborate and find synergies with our partner to the west — our friends in British Columbia — as well as our friends to the south."

"We feel there's great alignment between the provinces, the [Canadian] federal government and our friends in the U.S., with each region holding different strengths and advantages, and that collaboration and partnership can address those challenges, resolve the gaps within the supply chain, and really advance this economy swiftly and with purpose," Korol said. ■

Intermountain Power Plant in Delta, Utah, which LADWP plans to convert from coal to a gas-fired plant capable of burning a fuel mixture containing green hydrogen. | *Green Hydrogen Coalition*

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Bid-rigging Allegation Clouds Avangrid Bid for PNM

Utility Accuses Former Cybersecurity Contractor of Extortion

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County, N.M., cites emails he sent last August threatening to make his allegations to the New Mexico Public Regulation Commission (PRC) after the company declined to award SLI a contract.

Silva spoke at PRC meetings Aug. 9 and again Dec. 1, urging the regulators to reject Avangrid's bid for PNM, parent of Public Service Company of New Mexico and Texas-New Mexico Power (20-00222-UT).

In its countersuit, Avangrid said Silva's allegations "made obtaining approval from the PRC more difficult and more expensive."

Three of the five members of the commission said at Wednesday's meeting that they were leaning toward accepting a hearing examiner's recommendation that they reject the purchase. PRC Chairman Stephen Fischmann cited Avangrid's "absolutely horrible record of running U.S. utilities." Commissioners Cynthia Hall and Theresa Becenti-Aguilar also expressed opposition. The PRC has scheduled action on procedural orders in the merger docket on its meeting *agenda* for Dec. 8.

State Regulators React

In his appearance before the PRC on Wednesday, Silva said that Avangrid's "conduct artificially raised rates paid by consumers in New York and illegally enriched Avangrid's favorite … bidders." Avangrid is the parent of New York State Electric and Gas, which serves 883,000 electricity customers, and Rochester Gas & Electric, which serves 371,000 electricity customers.

The New York Public Service Commission did not respond to a request for comment Monday.

Avangrid also owns Central Maine Power, which has been under fire for poor service.

On Friday, Gov. Janet Mills urged the Maine Public Utilities Commission to "examine Avangrid's history of equipment purchases in Maine and to ensure that no Maine CMP ratepayer has been or will be harmed."

"Maine provides to its electric utilities a monopoly and, in return, they owe to Maine people reliable service at just and reasonable rates — nothing less," Mills said. "Any act of wrongdoing or any misconduct that harms Maine people deserves swift action, accountability and consequences."

Security Limits Inc. headquarters in Jessup, Pa. | *Security Limits Inc.*

"The allegations made against Avangrid are serious, and we will be reviewing the filings in federal court and following the proceedings closely," PUC Chairman Phil Bartlett said in a statement Monday to *RTO Insider*. "As we learn more, we will determine what additional review by the commission may be warranted."

Avangrid also is the parent of United Illuminating, which provides electricity to 328,000 residential, commercial and industrial customers in the New Haven and Bridgeport areas of Connecticut. The Connecticut Public Utilities Regulatory Authority said Monday it "will monitor the lawsuit and the allegations."

"During rate proceedings, the authority thoroughly examines the costs proposed by the utilities for recovery to determine prudency," PURA spokesperson Taren O'Connor said in an email to *RTO Insider*. "If the authority finds that any utility engaged in the alleged conduct, the associated costs would be disallowed and the authority would consider whether further actions are warranted based on the specific set of circumstances, including, but not limited to, civil penalties, fines and other actions."

Silva's attorney, John Griem of Carter Ledyard & Milburn, said, "We don't have any direct knowledge about" whether Avangrid's alleged bid rigging affected ratepayers in Connecticut and Maine in addition to New York. "I think a reasonable reader of our complaint could infer that this was a company-wide issue, and that investigation would be warranted," he said in an interview.

'Disgruntled Former Subcontractor'

Avangrid's suit describes Silva as "a disgruntled former subcontractor," saying he was soured by a $178,000 payment dispute with another Avangrid contractor, *Unlimited Technology Inc.* (UTI).

It said that Silva threatened to make public his allegations unless the company awarded SLI additional contracts. "When Avangrid refused their extortion attempt, defendants made false, defamatory and malicious public statements designed to harm Avangrid."

Avangrid said Silva and SLI "continued to solicit work from Avangrid for more than a year after allegedly learning of fraud, corruption and national security issues. Although defendants claimed Avangrid and Iberdrola are a 'cabal'

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with the 'twisted moral compass' of Enron, they nonetheless actively sought work from Avangrid as late as five days before these statements to the PRC" in August, Avangrid's suit says.

Griem called Avangrid's countersuit "a PR stunt that threatens the rights of all consumers to raise concerns about corporate wrongdoing."

'A Mountain of Radically Overpriced Hardware'

Silva's complaint said that after getting hired by Avangrid in 2018 to improve its cybersecurity program, SLI — "a technology, engineering, architecture and consulting solutions firm" — was blocked from bidding on later projects because the utility steered contracts to companies "willing to participate in a pay-to-play scheme."

Silva's suit says Avangrid and Iberdrola (which it called the "utilities defendants") conspired with the vendors "to procure a mountain of radically overpriced hardware — including scores of routers and multiplexing units that, curiously, they took pains to unpack and install in racks — as if to vaguely suggest that they were configured and operational. Yet those units were never put into service, are quickly growing obsolete and are depreciating by the day."

The suit named as "vendor defendants" UTI, *Black & Veatch* (B&V), Madrid-based Prosegur Gestión de Activos and two of its subsidiaries, Cipher Security and Prosegur Security Monitoring Inc.

"SLI made procurements on a straightforward, open-book contract basis, with a fixed margin of 15%, providing no ready channel for the [capital expenditure] inflation the utilities defendants sought," the suit said. "The utilities defendants thus turned to the vendor defendants, contractors that were wholly aware that the utilities defendants wanted to inflate CAPEX and were happy to assist them in the bid-rigging scheme."

Silva's suit says Avangrid and Iberdrola conspired with the vendors "to procure a mountain of radically overpriced hardware — including scores of routers and multiplexing units that, curiously, they took pains to unpack and install in racks — as if to vaguely suggest that they were configured and operational. Yet those units were never put into service, are quickly growing obsolete and are depreciating by the day."

The suit said Avangrid, Iberdrola and Prosegur allowed the sharing of SLI's trade secrets and bidding information with competitors. "On numerous occasions, the utilities defendants reissued earlier [requests for proposals] — for which SLI had already submitted best and final offers — to facilitate favored vendors, which would submit new bids styled to incorporate misappropriated SLI business secrets," it said.

Avangrid and Iberdrola "eschewed competitive bidding, engaged in customer and market allocation, and steered contracts to vendors willing to provide equipment and services that were neither competitively priced nor situationally appropriate (and in some cases unnecessary altogether)."

Silva's suit describes Prosegur as "a physical security company that would normally engage in the installation of video cameras and provide physical security and monitoring services … [that] has neither particular expertise in hardware and software sourcing nor in design and engineering services. Yet Prosegur entities were repeatedly chosen to bid on contracts requiring large-scale hardware acquisitions they were self-evidently unqualified to undertake and were awarded numerous sole-source contracts for related procurements and personnel."

Prosegur declined to comment. But Cipher Security COO and CFO *Andre Viera Rolim*, who was named a defendant in the suit, said in an email: "The company wants to highlight that it is always at the disposal of the authorities and courts of justice to collaborate in everything that is requested. Prosegur always acts with full respect for the rules and current legislation."

The suit alleges that UTI increased its warehouse three times over the past several years to store "tens of millions of dollars" in unneeded hardware equipment purchased to achieve Avangrid's quarterly capital expenditure targets.

Among the equipment procured were "tens of millions of dollars of overpriced and/or unnec-

Avangrid allegedly paid excessive prices to Thermo Bond Buildings, which makes communication shelters, substation buildings and modular data centers. | *Thermo Bond Buildings*

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essary hardware," including from *Thermo Bond Buildings*, which makes communication shelters, substation buildings and modular data centers. Other equipment included Nokia, CISCO and Pivot3 equipment "in wildly excessive quantity." Avangrid also purchased excessive amounts of data storage and unnecessary software systems, SLI said.

UTI did not respond to a request for comment.

Leaked Bid Information

The suit said Silva learned in 2018 that David Lathrop, Avangrid's manager of security technical services, conveyed confidential bid information to UTI through Charlie Von Stetten, UTI's operations director. "Lathrop would habitually leave vendors' bids open on his desk. On various occasions during that period, Silva witnessed Von Stetten whispering to Lathrop, after which Lathrop would leave his office. During Lathrop's absence, Von Stetten would take notes on the bids, sometimes even photographing them with his cell phone."

Silva said that when he raised the issue, "Lathrop smiled and replied, 'I know nothing; I was in the bathroom.'"

Silva said that as Lathrop was contemplating retirement from Avangrid, he sought a "post-retirement sinecure with an Avangrid vendor." After Silva said he rebuffed Lathrop, UTI hired him as a vice president of utilities in April 2020.

Before leaving Avangrid, Silva alleged Lathrop "steered" multiple procurements to UTI, including a $15 million contract in 2019 by providing UTI with a copy of SLI's confidential information.

Silva's suit refers to UTI as a company that "primarily installs and maintains video cameras to monitor large facilities" that had no experience "in designing or building private cloud data centers or in cloud systems integration."

A lawsuit alleges that while working for Avangrid, David Lathrop (left) allegedly leaked confidential bidding information to Unlimited Technology Inc. through UTI executive Charlie Von Stetten. UTI later hired Lathrop as vice president of utilities. | *David Lathrop & Charlie Von Stetten via LinkedIn*

But SDM Magazine in October *ranked* UTI as the No. 7 system integrator in North America for 2021.

On Dec. 2, private equity firm Lee Equity Partners announced it had *acquired* UTI. Lee did not respond to requests for comment Monday.

Black & Veatch

Silva's suit also cited a $34 million sole-source contract to B&V, a global engineering, procurement, consulting and construction company, in connection with a "data center convergence project."

Silva said that two Avangrid executives demanded that Silva share the contents of SLI's bid on a contract with B&V and that "SLI not seek the outright award of the contract, but instead relegate itself to serving as a subcontractor to B&V."

"SLI would later learn that B&V — well aware that it was using trade secrets extorted from SLI — used the specifications contained in SLI's bid in order to improve the B&V bid, and that B&V was ultimately awarded this lucrative, sole-source contract, despite its demonstrably inferior qualifications."

It also alleged personnel were hired directly through B&V to support a $1.5 billion automated metering infrastructure initiative "at premium hourly rates well in excess of the rates offered by SLI."

B&V spokesman Jim Suhr denied SLI's allegations.

"We are aware of this matter, but because this is actively pending litigation, we cannot comment beyond that we believe this suit is meritless and we intend to vigorously defend ourselves against it," he said.

National Security Threat?

In his first appearance before New Mexico regulators on Aug. 9, Silva alleged that Avangrid introduced "risks to national security" and suggested that Avangrid had hacked the computers of participants in the merger case.

Avangrid said the national security allegation appears to be a reference to one or two incidents, including the expiration of anti-malware software it used. The company said the malware lapsed in early 2020, "which was detected and resolved later that same year. This temporary expiration of anti-malware software was determined to not have any national security impact," it said.

The second incident concerned a private cloud server containing 150 GB of data that is the subject of a payment dispute between SLI and UTI. Avangrid said SLI is currently maintaining the server, and neither UTI nor Avangrid is willing to take custody of it. "But there is no sensitive data or data affecting national security on that server."

In his first appearance before New Mexico regulators on Aug. 9, Silva alleged that Avangrid introduced "risks to national security" and suggested that Avangrid had hacked the computers of participants in the merger case.

NERC declined to comment on Silva's allegation. The Northeast Power Coordinating Council did not respond to a request for comment.

Silva's attorney Griem said his client made several efforts to tell Avangrid about the problems in maintaining the cybersecurity system he helped to design but was met with "indifference or silence."

"When you charge ratepayers a tremendous amount of money in order to build a system, and then you don't properly install it or keep the software updated, given the news around what happened with the [hack of] Continental Pipeline, I certainly think it's fair to call poorly maintained and hackable infrastructure systems a national security issue."

Avangrid said Silva also implied that the company is hacking computers, having said, "Anyone attending these proceedings that has spoken against this merger, I strongly urge you as a cybersecurity professional to rebuild all of your computers, change all your passwords, as I have reason to believe that Avangrid is obtaining lots of information through incorrect channels about these proceedings."

"This statement is also defamatory and false," Avangrid's suit said. "It falsely accuses Avangrid of committing a crime in connection with the PRC proceedings." ■

FERC/Federal News

Experts Talk Carbon Markets at Ontario Energy Conference

By Jason York

Canada has had a price on carbon pollution at the federal, provincial and territorial levels since 2019, but it's not a perfect system, says Lisa DeMarco, senior partner and CEO of Canadian law firm Resilient.

Carbon pricing in Canada, which reflects the country's constitutional, federalist structure, is "strange," DeMarco said during the annual Association of Power Producers of Ontario (APPrO) energy and networking conference Nov. 30.

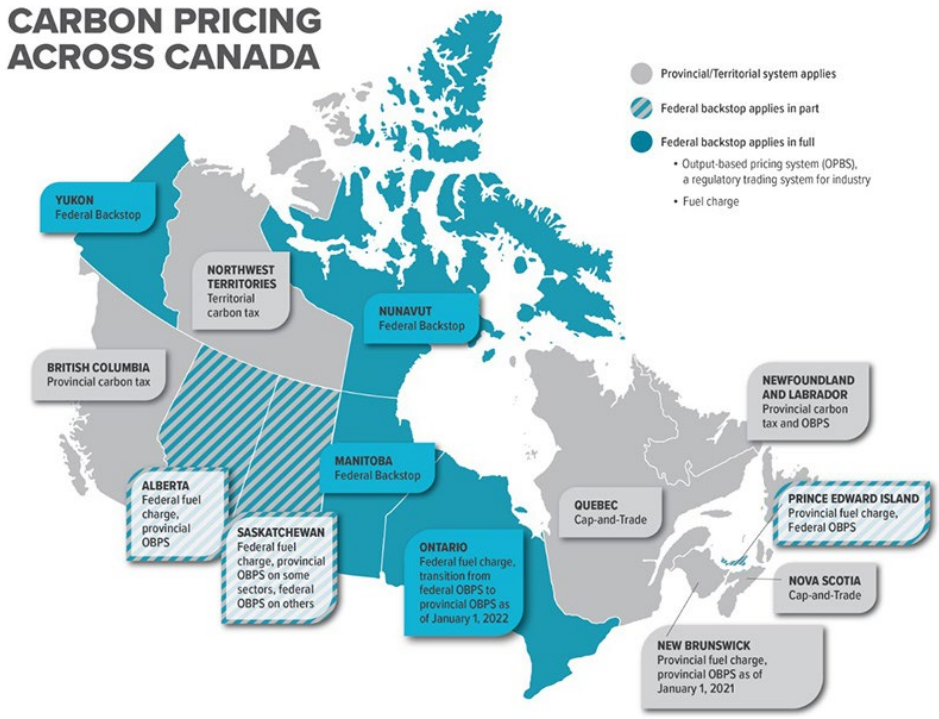
In what is supposed to be a flexible approach, a province or territory can design its pricing system or choose the federal pricing system. However, the federal government sets benchmark stringency standards that any carbon pricing scheme must meet to ensure it is comparable and effective in reducing emissions. If a province or territory decides not to price pollution or proposes a system that does not meet these standards, the federal system is implemented for consistency and fairness.

The federal price has two parts: a regulatory charge on fossil fuels such as gasoline and natural gas, known as *the fuel charge*, and a performance-based system for industries, known as the *Output-Based Pricing System*.

Provinces challenged the constitutionality of the federal system, but Canada's Supreme Court upheld the government's ability to set minimum national standards for carbon pricing.

Canada is covered entirely by various forms of carbon pricing. In New England, carbon pricing is a political hot potato. However, its high-profile advocates include ISO-NE CEO Gordon van Welie; U.S. Sen. Sheldon Whitehouse (D-R.I.); and New England Power Generators Association President Dan Dolan, who spoke at an APPrO panel Nov. 29.

With the looming elimination of the minimum offer price rule and a glut of state-sponsored resources entering the market, Dolan said the question is, "How does the market evolve?" New England has aggressive decarbonization and net-zero targets, driven by Massachusetts and Connecticut, which represent more than 80% of GDP and electricity load, Dolan said. Transportation represents the bulk of emissions in New England, twice the amount of any other sector in the economy and "the only one that has actually gone up," Dolan said.



| *Government of Canada*

Power plant emissions, he added, have "fallen off a cliff" for New England, and now the region has "one of the cleanest fleets" in the country.

"Yet that is continuing to [be] where we see more focus put, in large part, because of political expediency," Dolan said. "But how we then break that curve on the transportation side and bring in heating is going to be key to the overall foundation of where we can power this economy moving forward."

Crossing the Border

In July, the Canadian government said its carbon price will increase by $15/year after 2022 until it reaches $170/ton in 2030. However, that could lead to disparities with international trading partners, including the U.S. As a result, Canada is *exploring* Border Carbon Adjustments (BCAs), which account for differing carbon costs incurred in producing internationally traded goods.

BCAs could include import charges applied to goods from countries that do not have carbon pricing or use a lower carbon price to ensure that they face similar carbon costs. Export rebates can also be provided so that domestically produced goods compete on equal footing in foreign markets, alongside goods from countries with limited or no carbon pricing.

BCAs are not high on the policy docket at the moment, said Mitchell Davidson, executive director of Canada's StrategyCorp Institute of Public Policy and Economy. The last thing that Canadian Prime Minister Justin Trudeau wants to do "is make things more expensive, even if it's already doing that in some capacity with carbon pricing," Davidson said.

Moreover, he said, the additional level of tariffs that would come with BCAs amid rising prices and supply chain issues make it "a low likelihood" for any immediate action.

"Although in the future it is certainly something that the government could seriously consider," Davidson said of BCAs.

The better policy, said Scotty Greenwood, managing director of Crestview Strategy in Washington, is to have a "North American approach" for energy pricing and carbon transition.

"I think that is more productive to think about how we do that than trying to look at how we compete on something like carbon," Greenwood said. ■

FERC/Federal News

SEIA Policy Forum Asks 'To RTO or not to RTO?'

Glick, Clark and Kelly Debate Options for States

By K Kaufmann

WASHINGTON — Organized power markets have proven their worth over the past 20 years, but, former FERC Commissioner Tony Clark says that doesn't mean RTOs are the best choice for states in the West and Southeast seeking regional cooperation and reliability.

A senior adviser at Wilkinson Barker Knauer, Clark said RTO membership should be a state decision. "As we move forward, are there third ways that are going to develop? It seems like there kind of are in ways that make sense for those regions," he said at the Solar Energy Industries Association 30x30 Policy Forum on Thursday. He cited current discussions about regional resource adequacy in the Pacific Northwest and the Southeast Energy Exchange Market recently approved by FERC.

"To RTO or not to RTO?" was the question posed to Clark, current FERC Chair Richard Glick and former Commissioner Suedeen Kelly at the SEIA conference. The solar trade association has set a goal of solar providing 30% of U.S. power generation by 2030, and organized markets will be critical in that effort, said moderator Gizelle Wray, SEIA's director of regulatory affairs.

"Organized wholesale markets are the key to unlocking the cheapest, most reliable and affordable solar in the country," Wray said. "We have seen time and time again that wholesale markets provide our members — independent power producers — with opportunities that are not afforded in vertically integrated states.

Suedeen Kelly, Jenner & Block | © *RTO Insider LLC*

FERC Chairman Richard Glick | © *RTO Insider LLC*

At the moment, only organized wholesale markets are capable of providing the long-term certainty that clean energy businesses need to deploy solar and storage at scale."

Glick said he favors RTOs and the benefits they provide in terms of economies of scale and regional power integration and reliability, but mandating their formation raises some thorny issues of jurisdiction. While he believes FERC does have the authority to mandate RTO membership for Western states, any such effort would not apply to municipal and public power utilities — such as the Bonneville Power Authority or the Los Angeles Department of Water and Power — which are outside of the commission's authority.

"I think we need to encourage RTO development," Glick said. "I think the time is now to act. We see the threats due to weather [and] the lack of resource sufficiency in certain areas. If [the states] don't start working together, I think we're going to see some calamitous issues."

Kelly, partner at Jenner & Block, also underlined the advantages of RTOs — creating large, integrated transmission networks that foster reliability and eliminate unnecessary costs — but, like Clark, she saw the need for more flexible market structures. The West's Energy Imbalance Market, while valuable, does not include a transmission component, she said, which makes it inefficient and difficult for "people in Santa Fe or Albuquerque to get an electron from California because they have to go through all the transmission [issues]."

"The states in the West come at this at a time when they've seen a history of how RTOs work," Kelly said. "Most of those states want to see more renewables and a cleaner electricity mix. They have the opportunity to create an RTO that is not a cookie cutter, and my sense is that this FERC would be open to a construct that is not cookie cutter; rather [one] that is designed to achieve the goals" of those states.

Flexibility and False Dichotomies

The hundreds of gigawatts of solar and storage projects in interconnection queues across the country are, Wray said, "stuck in a perpetual waiting room because the transmission pathways to the markets are not being built."

"This is not acceptable if we want to deploy a

FERC/Federal News

record amount of solar across the country," she said. "We want FERC to reform the transmission planning process to include interconnection. Right now, renewable energy generators are left guessing which projects are needed and where, and these reforms will help to clarify the process and send the right market signals."

Glick said changes to transmission planning are major priorities at FERC, with the Advance Notice of Proposed Rulemaking potentially providing solutions to bottlenecked interconnection queues. He expects a proposed rulemaking "by early next year," he said.

As more renewables come onto the grid, flexibility, along with reliability, will be a key issue, Glick said. "There are certainly lots of ways to handle reliability, but how do you attract, how do you encourage flexibility?" he said. "Whether it's gas or storage, how do you encourage, how do you incent [it] so it's adequately compensated for the value it provides to the grid?"

While agreeing that thorough-going changes are needed, Clark argued that RTOs are not the only answer, particularly for reliability. "There's sometimes a false dichotomy that's presented to public policymakers, which is on one hand here, we have markets and free enterprise and competition and that's RTOs, and on the other hand we have big, bad old [state] regulation," he said.

Drawing on his experience at FERC and as a state regulator in North Dakota, Clark said, "There's as much politics and rent seeking and regulatory capture in the RTO stakeholder processes as we ever dealt with in the cost-of-service regime. So, what you're really dealing with is a couple of different administrative constructs, both of which can utilize myths of competition, or elements of competition, to try to drive outcomes that are good for consumers."

States with vertically integrated utilities may be better at ensuring capacity than those with restructured retail power markets, Clark said. "The reason is because if you need to retain that sort of dispatchability in your capacity, you just go to your state commission [and] you build it into rates," he said. "It's going to be a trickier situation in most regions that have transitioned away from that.

"In my mind, Texas is kind of the canary in the coal mine on that issue," he said, referring to last winter's power outages in the state.

Getting Rid of Barriers

Kelly noted that the U.S. has experimented with a range of market-making strategies. The Public Utility Regulatory Policies Act helped kick-start the commercial and utility-scale solar market, she said.

Creating markets through incentives could be the "advantageous" result of the Build Back Better Act, with its $555 billion in funding for tax credits and other clean energy programs, she said.

But FERC's creation of the RTOs and wholesale power markets was "revolutionary" for the U.S., she said. Beyond economies of scale and cost savings, the deployment of new technologies was also a core driver for the initial formation of RTOs, she said. But at that time, combined cycle natural gas plants were the "new guy on the block" facing market barriers from vertically integrated utilities, she said.

Tony Clark, Wilkinson Barker Knauer | © *RTO Insider LLC*

The caveat, Kelly said, is that state participation in RTOs is "optional, but an option that I think everyone should have available to them. The more buyers and the more sellers that can come together in one place, the better."

Glick said FERC's role is to remove barriers to markets, such as the commission's orders opening wholesale markets to demand response (*Order 745*) and energy storage (*Order 841*).

"But we have a lot more to do in terms of hybrid resources," such as solar and storage projects, he said. "Are there market rules out there discriminating against hybrid resources? Offshore wind is another area we need to take a look at; are there barriers there we need to get rid of? That's the prime objective the commission needs going forward: getting rid of barriers." ■

SunZia Capacity Allocation

SunZia Transmission, L.L.C. (SunZia) has commenced an open solicitation process for capacity on the proposed SunZia Southwest Transmission Project (Project). SunZia intends to allocate approximately 1500 MW of the Project's remaining capacity through an open and transparent solicitation and capacity allocation process.

The Project consists of a single-circuit 500-kV high-voltage direct current (HVDC) line and associated substations that is expected to deliver primarily renewable energy on an approximately 550-mile route from central and southwestern New Mexico and southeastern Arizona to load-serving entities in Arizona, California, and other western markets. SunZia is offering firm transmission service from SunZia East to Pinal Central and Owl Head. SunZia expects to achieve commercial operation in 2025, with construction commencing in 2023.

Interested parties can learn more about the SunZia Southwest Transmission Project open solicitation process and how to participate by visiting **www.sunzia-os.net**. For more information about the Project visit **https://sunzia.net**.

In order to obtain transmission capacity rights on the Project, interested parties must submit a nonbinding Expression of Interest Form through the Open Solicitation website by **December 17, 2021.**

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Southeast

SEEM Members Seek to Quash Rehearing Requests

Lateness Central to Southeast Utilities' Argument for Dismissal

By Holden Mann

Members of the recently approved Southeast Energy Exchange Market (*SEEM*) on Nov. 29 called for FERC to reject the rehearing requested by the market's critics earlier this month (*ER21-1111, et al.*).

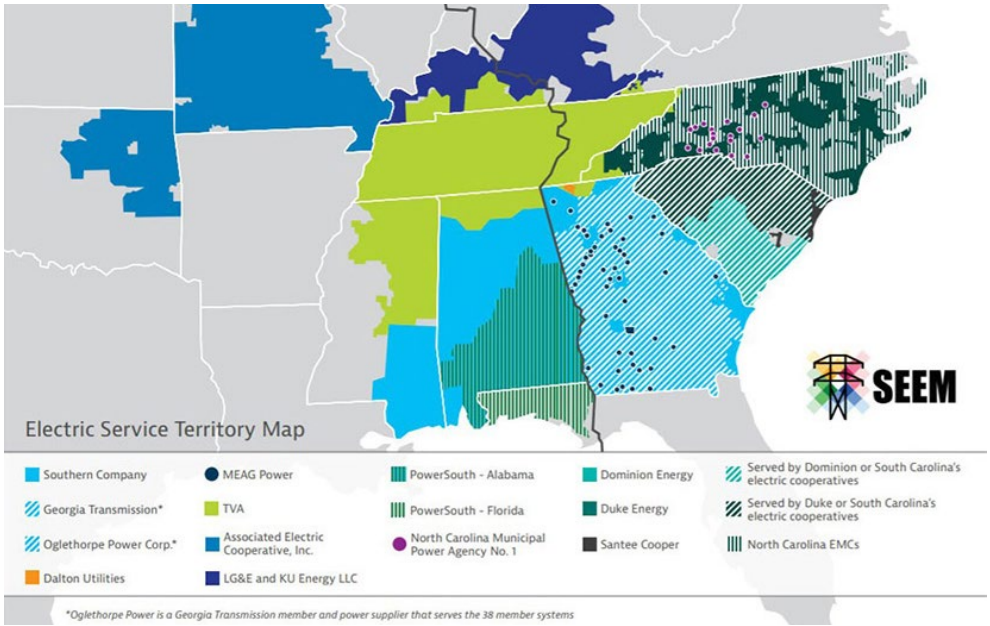
The commission received two requests for rehearing on Nov. 12. One was filed by an *ad hoc* group of environmental and clean energy organizations calling themselves the Public Interest Organizations (PIOs), and the other by a separate group calling itself the Clean Energy Coalition. (See *SEEM Opponents File Rehearing Requests*.) Both groups urged FERC to reconsider its *de facto* approval of the SEEM agreement, which took effect Oct. 12 under Section 205 of the Federal Power Act after commissioners split 2-2 on approval. (See *SEEM to Move Ahead, Minus FERC Approval*.)

In their filing, SEEM members — a collection of utilities including Southern Co., Dominion Energy South Carolina, LG&E and KU, the Tennessee Valley Authority and Duke Energy — said the opponents' request should be denied for several reasons.

The first issue the utilities raised was the timing of the rehearing requests, which they said by itself should be enough to quash the petitions. Under the FPA, any parties "aggrieved" by a FERC order may apply for rehearing within 30 days of its issuance. While the opponents filed their requests Nov. 12, which was 30 days after the commission's announcement that the agreement had taken effect, the SEEM members asserted that this was actually two days after the deadline.

In their filing, the members argued that the "date of issuance" is not when the commission announced the decision, but when it failed to issue an order. Members cited FPA Section 205(g), which states that "the failure to issue an order accepting or denying [a] change … shall be considered to be an order issued by the commission accepting the change." Under this wording, they said, the date that FERC failed to issue an order should be considered "no later than Oct. 11" — 60 days after the members filed their answer to FERC's second deficiency letter. (See *SEEM Members Push for FERC's Decision on Market Proposal*.)

SEEM members acknowledged some discrepancies between FERC's announcement of the SEEM approval and the statements of commissioners: Commissioner Allison Clements suggested in a statement explaining her vote that the "statutory deadline" for FERC action in the proceeding was Oct. 8, while FERC's notice said the deadline was Oct. 11. However, they emphasized that none of the previous filings in this case have stated any deadline after Oct. 11, which means that the 30-day deadline for rehearing requests expired Nov. 10, two days before the PIOs and CEC filed theirs.



Map of Southeast Energy Exchange Market's footprint | *SEEM*

Additional Claims Dismissed

Along with arguing to deny the rehearing requests on timing grounds, SEEM members dismissed the "substantive issues" raised in the requests as "largely moot" in light of their filing Nov. 24 in which they offered to implement a series of modifications intended to provide greater transparency. (See *SEEM Members Embrace Market Changes*.)

The issues dismissed by the utilities include concerns of the PIOs and CEC over the market's use of the *Mobile-Sierra* doctrine, which presumes that any freely negotiated wholesale energy contract is just and reasonable. FERC Chairman Richard Glick also cited this as a reason for opposing the market. (See *FERC's Christie Accuses Glick, Clements of Prejudice for RTOs*.) But SEEM members said this should no longer be a problem because they voluntarily offered in Nov. 24's filing to make the "just and reasonable standard" the default for most SEEM rules.

Also dismissed by SEEM members were opponents' fears about "the potential for exercise of market power" and monopolistic behavior by members. These concerns too should be negated by the "significant additional transparency measures" incorporated in the Nov. 24 filing, the utilities said.

The members did engage with the PIOs' and CEC's claim that the commission "has not engaged in reasoned decision-making" and that the commission's approval of the SEEM agreement without an accompanying order or explanation "cannot be just and reasonable." Calling this argument "odd," the utilities asserted that the mechanism in the FPA by which SEEM took effect is intended by Congress for just such an occasion when commissioners are unable to agree on a course of action.

"In every such case there will not be a written opinion of the commission explaining the reasons the [decision] is just and reasonable," members said. "Rather, it is just and reasonable because Congress said it is, subject to review on rehearing and by an appellate court, if pursued."

FERC has 30 days to act on the merits of the rehearing request. If it fails to do so, the petitioners may appeal to the D.C. Circuit Court of Appeals. ■

CAISO/West News

FERC Accepts CAISO Hybrid Rules

RAAIM Exemption Protested, Questioned by Danly

By Hudson Sangree

FERC on Nov. 30 approved the second round of CAISO's tariff changes for co-located and hybrid resources, the result of a two-year stakeholder *initiative* meant to accelerate the pairing of renewable generation with storage to ensure California has adequate resources during its clean energy transition. (*ER21-2853*).

The changes include a contested provision exempting hybrid resources from CAISO's resource adequacy availability incentive mechanism (RAAIM), which CAISO said would reduce the risk of double penalizing the resources by assessing their performance based on historical output.

FERC agreed with the change, saying it had *approved* CAISO's RAAIM exemption in October 2015 for variable energy resources under the same rationale.

"The use of a qualifying capacity methodology that discounts qualifying capacity by taking into account historical performance could lead to effectively penalizing a variable energy resource for a second time under the RAAIM framework," FERC said. "We find that CAISO has adequately explained why hybrid resources, if subject to RAAIM, would face a similar risk of a double penalty here, and therefore that an exemption is also warranted for them."

Middle River Power, a private equity firm that manages six natural gas plants and other generating assets in California, argued it was unreasonable to exempt hybrid resources from RAAIM. Hybrids combining solar or wind and battery storage represent "a significant portion of future resources that will be providing resource adequacy capacity to the CAISO" and should be subject to the same market rules as other RA resources, it said.

"Middle River argues that CAISO's characterization that resource adequacy values for variable energy resources are determined by their historical performance is inapt," FERC said. "Middle River explains that ELCC [effective load carrying capability] studies apply aggregate variable energy resource generation profiles, based on historical output (determined by historical weather), to a forecast of weather in future years. Middle River states that asserting that a variable energy resource's qualifying capacity value is affected by its historical performance overstates the role an individual resource's performance plays in setting its ELCC-based qualifying capacity value."

FERC said it was unpersuaded by Middle River's argument "that the Commission should re-examine the premise underlying the proposed exemption for hybrid resources given that variable energy resources' qualifying capacity values are no longer based on the historical performance of an individual resource."

'Bleeding to Death'

Commissioner James Danly concurred with Chair Richard Glick and commissioners Allison Clements and Mark Christie in the decision.

"I agree that [CAISO] proposed a just and reasonable method by which hybrid and co-located resources can participate in the markets [it] administers," Danly said. "Enhanced participation of these resources is critical because CAISO faces serious reliability and resource adequacy problems."

The ISO has encountered strained grid conditions during the last two summers, including the rolling blackouts of August 2020, and expects another difficult summer in 2022. Extreme weather, wildfires and the switch from fossil fuels to clean energy without sufficient storage have been partly to blame.

Danly said he wondered whether exempting hybrid resources from RAAIM made sense in such circumstances.

"RAAIM is designed to improve resource performance, so exempting another entire class of resources from it appears to be problematic on its face, especially in a region suffering an ongoing reliability crisis," he wrote. "But our Federal Power Act standard of review is whether a proposal is just and reasonable, not whether there is a better idea."

He said he was persuaded that there was a risk of double penalties under RAAIM for hybrid resources if historical outage data was included in the capacity-factor calculation.

"So, while I agree with approving this proposal, I remain concerned that CAISO continues to use Band-Aids to address its ongoing reliability challenges rather than the emergency surgery that is actually required," Danly said. "Each Band-Aid may mark a modest incremental improvement, but the patient is still bleeding to death.

"Today's order is a perfect example," he said. "CAISO almost certainly can find ways to incorporate hybrids and variable resources into its markets without RAAIM exemptions or other potentially discriminatory measures."

Reporting Requirements

Danly said he supported FERC's decision to require CAISO to provide an update next year on whether the RAIMM exemption is discriminatory.

Additional tariff changes accepted Nov. 30 included CAISO's requirement that hybrid and co-located resources provide additional data on weather and state-of-charge, as well as a requirement that each hybrid resource and co-located intermittent resource provide its "high sustainable limit" via telemetry every 12 seconds.

"CAISO explains that this parameter is a real-time estimate of the instantaneous maximum output capability of a variable energy resource or the variable component of a hybrid resource, based on the resource's physical properties and weather conditions," FERC said.

FERC approved CAISO's first set of tariff changes dealing primarily with co-located resources in November 2020. (See *FERC Accepts CAISO Co-located Resources Plan*.)

CAISO intends to begin a stakeholder initiative on the evolution of hybrid resources starting next year. ■

Wind turbines in the Southern California desert. | *Shutterstock*

CAISO/West News

CPUC Orders Procuring 3 GW of Capacity

Commission Approves Plans to Prevent Shortfalls in Extreme Summer Conditions

Continued from page 1

include:

- expanding the use of a central procurement entity to ensure local reliability served by community choice aggregators and other load-serving entities;
- doubling the payment to participants in the CPUC's Emergency Load Reduction Program to $2/kWh and paying residential customers the same rate for reducing use during grid emergencies; and
- funding a $22.5 million smart-thermostat incentive program "designed to reduce air conditioning a few degrees during emergencies" and creating pilot programs "to test the effectiveness of dynamic rates that change rapidly in response to grid emergencies."

Other measures allow PG&E to install additional temporary gas generators and authorize SDG&E to build four new microgrid projects totaling 160 MW. (See *CPUC Proposes Summer Reliability Measures*.)

Since late 2019, the CPUC has directed the state's IOUs to collectively procure more than 17 GW of additional capacity, including a June order for 11.5 GW of new resources to come online between 2023 and 2026. The rolling blackouts of August 2020 and energy emergencies the past two summers lent urgency to the efforts.

Thursday's actions were taken in response to an emergency declaration by Gov. Gavin Newsom in July that said the state could face up to a 5-GW shortage this summer. A subsequent CPUC analysis found the shortage to be 3 GW at most.

The commission cited the potential for continuing high temperatures, wildfires and drought in the West as reasons for boosting the planning reserve margin in CAISO territory to 20-25% in the coming summers.

The state's increasing reliance on solar power — which ramps down as the sun sets — adds to the challenge, the decision said.

"This perfect storm of reliability challenges requires urgent action now," it said. ■

CAISO/West News

Nevada Gov. Sisolak Appoints Regional Tx Task Force

By Elaine Goodman

Nevada Gov. Steve Sisolak on Thursday announced the membership of a panel that will advise the governor and legislature on potentially bringing the state into an RTO.

Formation of the Regional Transmission Coordination Task Force is a mandate of *Senate Bill 448*, a wide-ranging energy bill that Sisolak, a Democrat, signed into law on June 10. (See *Many Next Steps to Follow Passage of Nevada Energy Bill*.)

Sisolak named Sen. Chris Brooks (D), the bill's author, as chairman of the task force. Its other 18 members include representatives of utilities, labor, environmental groups, business and government.

The governor's office expects to add five more task force members in coming weeks.

"This task force will further advance our state's mission of developing our infrastructure, bolstering our commitment to renewable energy and building out our green energy economy," Sisolak said in a release.

RTO by 2030

SB 448 includes a requirement for transmission providers to join an RTO by January 2030, unless they can show that they haven't been able to find a viable RTO or that joining an RTO wouldn't be in the best interest of the providers or their customers.

The Regional Transmission Coordination Task Force will formulate advice on topics and policies related to regional energy transmission in the West.

Under the provisions of SB 448, the task force will study the potential costs and benefits of forming or joining an RTO, for transmission providers and their customers in Nevada. The task force may bring in an independent third party to help analyze those costs and benefits.

The panel will explore policies to help bring transmission providers in the state into an RTO by 2030, including whether any legislation is needed to allow the providers to join an RTO.

The task force will also look at business the state could attract by having a position in a regional wholesale electricity market. It will look at locations for new transmission facilities that would help achieve the state's clean energy and economic development goals.

The task force will meet at least twice a year and send a report to the governor and legislature by Nov. 30, 2022, ahead of the state's 2023 Legislative session.

Nevada Gov. Steve Sisolak (left) with state Sen. Chris Brooks, who was appointed chair of the state's newly created Regional Transmission Coordination Task Force | *Gov. Steve Sisolak via Twitter*

Cost Savings, Reliability

Western Resource Advocates, which has a representative on the task force, pointed to a *market study* this year that found Western electricity customers could save more than $2 billion a year if a single market operator managed transmission and coordinated generation planning. Such a move could also support renewable energy development and improve reliability. (See *Study Shows RTO Could Save West $2B Yearly by 2030*.)

"The state task force's work on a Western regional transmission organization will help Nevada reap the economic, environmental and reliability benefits of regionalization," Vijay Satyal, Western Resource Advocates' regional energy markets manager, said in a *release*.

Members of the Regional Transmission Coordination Task Force are:

- Sen. Chris Brooks (chairman)
- David Bobzien, director, Governor's Office of Energy
- Kris Sanchez, deputy director, Governor's Office of Economic Development
- Carolyn Barbash, vice president, transmission development and policy, NV Energy
- Carolyn Turner, executive director, Nevada Rural Electric Association
- Cameron Dyer, managing senior staff attorney, Western Resource Advocates
- Eric Witkoski, executive director, Colorado River Commission of Nevada
- Erik Hansen, chief sustainability officer, Wynn Resorts
- Jeremy Newman, assistant business manager, IBEW Local Union 396
- Leslie Mujica, executive director, IBEW/NECA/LMCC - Las Vegas Power Professionals
- Luke Papez, director, project development, LS Power Development
- Richard Perkins, president/CEO, The Perkins Co.
- Mona Tierney-Lloyd, head, U.S. state public policy and institutional affairs, Enel North America
- Samuel Castor, EVP of policy, Switch
- John Seeliger, regional energy manager, Nevada Gold Mines
- Kostan Lathouris, managing member, Lathouris Law PLLC
- Rebecca Wagner, owner/consultant, Wagner Strategies
- Elizabeth Becker, FEMA, Local Hire - emergency management specialist
- Hayley Williamson, chair, Public Utilities Commission of Nevada ■

CAISO/West News

CPUC Assesses PG&E $125M for Kincade Fire

Controversial Settlement Process Used to Hasten Utility Accountability

By Hudson Sangree

The California Public Utilities Commission on Thursday adopted fines and penalties of $125 million against Pacific Gas and Electric for starting the 2019 Kincade Fire, using a new enforcement tool that caused unusual discord among the CPUC's five commissioners, who tend to vote unanimously.

The new expedited enforcement measure, called an administrative consent order (ACO), is a settlement process intended to reduce the time it takes the CPUC to hold utilities accountable for safety violations in an era of catastrophic wildfires. Other *enforcement* proceedings, such as the commission's order instituting investigation, can take years to complete.

The CPUC created its new mechanism in November 2020 when it adopted a revised *policy* to promote timely enforcement of safety violations.

"The addition of these tools to the CPUC's enforcement options in 2020 moved the CPUC's practices more in line with the enforcement practices of many other state and local enforcement agencies," the commission said in a statement last month.

The CPUC used its ACO option for PG&E in the Kincade Fire and for Southern California Edison (SCE) in the major fires of 2017/18, including the Thomas and Woolsey fires. The CPUC was set to take up an *agreement* with SCE to impose $550 million in fines and penalties for the catastrophic blazes on Thursday but moved the matter to its Dec. 16 voting meeting pending further review.

Commissioners *voted* 3-2 to approve the *agreement* between PG&E and the CPUC's Safety and Enforcement Division that levied $40 million in fines and denied the utility $85 million in cost recovery for removing abandoned transmission lines.

A disused but energized transmission line leading to The Geysers, Calpine's 650-MW geothermal plant in Sonoma and adjoining counties, started the Kincade Fire when a jumper cable broke, sparking dry vegetation below, an investigation by the California Department of Forestry and Fire Prevention found. The blaze burned nearly 78,000 acres of the region's forested hills and famed wine country, destroying 374 structures and injuring four firefighters.

PG&E faces a criminal prosecution and lawsuits the utility estimated could cost up to $800 million over the Kincade Fire. It settled claims with Sonoma County and four cities affected by the fire for $31 million in May. (See *Prosecutors Charge PG&E for 2019 Kincade Fire* and *Wildfire Liability, Criminal Charges Cloud PG&E Outlook*.)

The agreement between PG&E and the CPUC settles only the claims of state regulators.

Commissioners at Odds

Commissioners Darcie Houck and Genevieve Shiroma, who voted against the order, said they agreed with commenters such as *The Utility Reform Network* that the matter deserved a longer and more in-depth public airing.

Houck noted that PG&E's equipment caused the San Bruno gas pipeline explosion in 2010 and a series of catastrophic wildfires over the last seven years that killed more than 100 people. The CPUC has repeatedly criticized PG&E in official letters for its alleged safety failures, including five times in the past year alone, she said. (See *CPUC Applies New Safety Metrics to PG&E*.)

"Given the number and severity of these events, I believe that we should be providing greater scrutiny to the proposal before us," Houck said.

"Investigation and resolution of a large-scale utility-caused disaster through a black-box settlement and resolution outside of a more formal process … is concerning to me," she said. "It excludes impacted communities, ratepayer advocates and the public from being able to provide meaningful input up front as to the reasonableness of the proposal, potential rate implications and recommendations … [about] changes in utility operations."

Those who voted for the agreement said they believed it achieved a just result in far less time than the CPUC's traditional investigation and enforcement process.

"When it comes to our enforcement actions, I have been very troubled by the time that it takes, in some cases five to six years … and I'm not sure that's doing quite as much justice as something that is akin to what's before us, which is far more prompt and what I think is a fair outcome," Commissioner Martha Guzman Aceves said.

CPUC President Marybel Batjer and Commissioner Clifford Rechtschaffen joined her in voting for the ACO.

The Kincade Fire destroyed 374 structures, including the Soda Rock winery in Healdsburg, Calif. | *© RTO Insider LLC*

"With the adoption of the administrative consent orders as part of our enforcement policy, this was a step forward in giving our expert safety and enforcement staff new tools to bring timely enforcement actions, all with the intention of driving accountability from the utilities and in the end to create a more-safe system for our customers," Batjer said.

PG&E Disputes Allegations

The CPUC did not require PG&E to admit to any safety violations as part of the agreement.

The three main violations that formed the basis of the agreement included allegations by the CPUC's Safety and Enforcement Division (SED) that PG&E had disconnected one of its lines from a mothballed portion of The Geysers plant but had "left the jumper cables on [one tower] attached to the ends of suspension insulators that were hanging freely from the tower arm." That "allowed for more than typical movement of the suspension insulator string" causing the jumper cable to wear and break loose, the CPUC said.

"Accordingly, SED asserts the Geysers #9 line, as left by PG&E, was not constructed, or maintained, for its intended use," the *agreement* said.

PG&E denied the allegations, contending, for example, that prior to the Kincade Fire, there were "no engineering standards, design drawings or guidance documents in the transmission industry that referenced the specific [tower] jumper configuration or that recommended or discouraged that specific configuration."

The company said in a statement last week that it had accepted the settlement because it would allow "all parties to move forward from the fire and permit us to focus on compensating victims and making our energy system safer." ■

CAISO/West News

Colo. PUC: State Could Save up to $230M in Wholesale Market

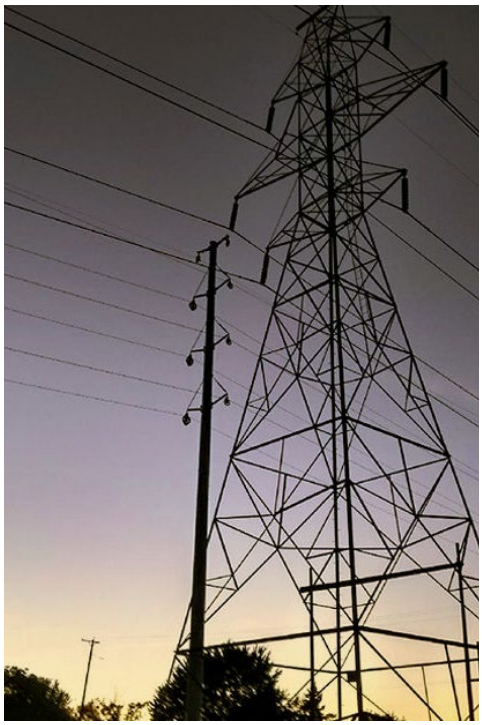
By Rebecca Santana

DENVER — A Colorado Public Utilities Commission *report* released last week found that joining an organized wholesale electricity market could save the state's utilities between $50 million and $230 million annually.

"These kinds of savings were generally found to exist independent of whether Colorado looked west to the CAISO, east to SPP or created something new in the middle working with neighboring utilities," the report said. It also found that joining a market — whether an energy imbalance market or an RTO — would accelerate the state's clean energy goals.

The PUC conducted the study in response to 2019's SB19-236, which directed the commission to investigate Colorado utilities participating in an organized wholesale market and determine whether it is in the public interest by Dec. 1. The PUC also discussed the potential of interstate transmission as a way to more rapidly decarbonize Colorado's grid earlier this year. (See *Colo. Regulators Consider the Advantages of Interstate Tx*.)

In June, Gov. Jared Polis signed legislation (*SB21-072*) requiring all utilities with transmission facilities to join an organized wholesale market by Jan. 1, 2030. (See *Polis Signs Bipartisan Bill to Support Interstate Tx*.)



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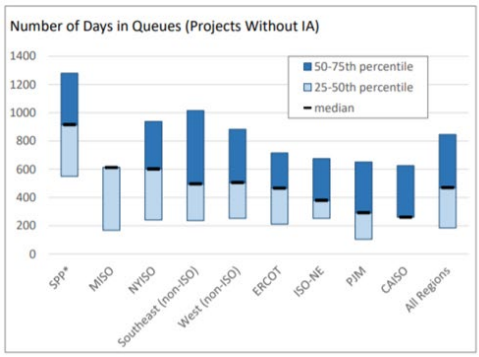
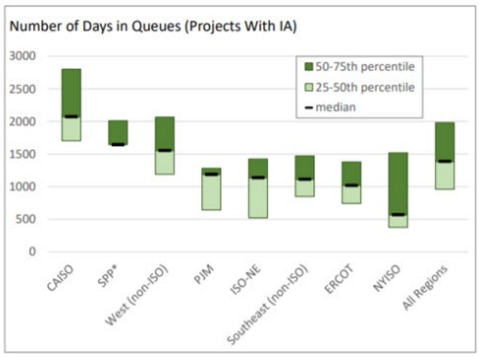




RTO interconnection access queue times | *Colorado Public Utilities Commission*

Colorado is not the only state to have passed legislation requiring its utilities to seek RTO membership. Nevada Gov. Steve Sisolak also signed *SB448* in June, and last week he appointed a task force to "capture the ideal conditions and requirements for a future regional transmission organization that will represent the changing economics, resource mix and decarbonization trends of the West," Vijay Satyal, Western Resource Advocates' regional energy markets manager, said in a press release.

CAISO or SPP?

As CAISO "already optimizes real-time imbalance energy over 84% of the Western footprint," it would seem to be the obvious choice, the report said, but the PUC took issue with the ISO's governance structure, with a concern that states outside of California participating in the market may go unheard.

"The risk exists that CAISO could protect California's parochial interests at the expense of what is best for the region," the report said. It pointed to CAISO's recent filings concerning a wheel-through tariff that "appears to have significantly exacerbated and given substance to these concerns."

Along with governance, the commission is also concerned about CAISO's resource adequacy issues, which it says have delayed implementation of an extended day-ahead market in its EIM. Until the ISO has addressed this concern, "electric utilities in states like Colorado will likely need to be cautious about shifting control of their transmission assets to a process controlled by California," the report said.

The report said that joining SPP's Western Energy Imbalance Service (WEIS) would offer Colorado considerable short-term benefits, including improving dispatch and curtailment issues within the state. Unlike CAISO, WEIS "allows states [to] maintain control over resource planning and acquisition by their electric utilities, which has historically been well run in Colorado, creating considerable customer benefits."

But even so, WEIS' governance structure also leaves something to be desired, the report said. It raises concern for new utility entrants because "substantial voting rights [are] vested in individual power marketing agencies and cooperatives, with little opportunity for regulators to meaningfully participate."

As well as potential governance issues, the report notes the concern of interconnection access and SPP's overwhelmed queue.

"The inability to fairly and efficiently allocate interconnect to low-cost generators could delay new low-cost clean energy from coming online and would offer no direct mechanism for flowing the benefits through to native load customers," the report said.

Moving Forward

The report encourages Colorado transmission utilities to communicate with the grid operators to address these concerns and explore potential market options in the meantime. By requiring utilities to join an RTO, Colorado aims to improve interstate transmission in the West to promote resilience and reliability.

"Under these circumstances, one near-term course for Colorado's transmission utilities may be to participate in an EIM to resolve intrastate dispatch issues and to capture the enhanced near-term coordination benefits but preserve the flexibility to adjust as regional market opportunities in the West evolve," the report said. ■

ERCOT News

2 More Directors Appointed to ERCOT Board

The Texas Public Utility Commission on Wednesday announced Bob Flexon and John Swainson as the two latest additions to ERCOT's Board of Directors, leaving the body just two members short.

Flexon was Dynegy's CEO before its 2018 merger with Vistra and was previously CFO for UGI Utilities and NRG Energy. (See *Vistra-Dynegy Merger Closes After FERC Nod*.) He currently chairs Pacific Gas and Electric's board of directors and sits on several other governance groups. He gives the board just its second independent director with a background in the electric industry, alongside previous appointee *Zin Smati*.

Swainson is executive chairman of Travelport, a business-to-business marketplace for travel information, and an executive partner at Siris Capital, a technology-focused private equity firm. He was president of the Dell Software Group until its sale in 2016.

Flexon and Swainson were chosen by the ERCOT Board Selection Committee, a three-person group appointed by Texas' political leadership. The committee has been working with a search firm to fill the board's eight independent director slots, as directed by legislation passed earlier this year.

Robert Flaxon | © *RTO Insider LLC*


John Swainson | *Travelport*

Senate Bill 2 replaced the previous board's five unaffiliated directors and eight market segment representatives with eight independent directors chosen by the selection committee. The ERCOT CEO, the PUC chair and the Texas Office of Public Utility Counsel's CEO sit on the body as non-voting members.

One of the first five appointees, Elaine Mendoza, abruptly resigned Nov. 19 over an apparent conflict of interest. (See *Twitter Blows up over ERCOT Communications*.) ■

— Tom Kleckner

ERCOT News

Texas PUC Pushes 44% Reduction in ERCOT Offer Cap

Continued from page 1

$5,000/MWh as an "appropriate level," saying the ORDC should be designed to stabilize the existing fleet and ensure the real-time market operates effectively.

The ORDC "provides revenues with the right price incentives to behaving as they should … so they are online when the likelihood of scarcity is growing," he said. "We should use it to stabilize current market conditions."

Commissioner Lori Cobos agreed, saying the ORDC will help stabilize the existing generation but also "hopefully drive incremental generation."

"I don't want to minimize the importance of changes to the ORDC," she said. "These have been highly contested, debated issues in the past. It is by no means low-hanging fruit."

McAdams is also proposing to raise the ORDC's minimum contingency level from 2 GW to 3 GW, saying it will give ERCOT "breathing room" before hitting emergency conditions.

"All of these changes we are considering are expensive, but expensive is relative to the problems," Commissioner Jimmy Glotfelty said. "It's warranted based on what all Texans have experienced. It's the right policy to move forward."

The high systemwide offer cap (HCAP) was lowered to the low cap of $2,000/MWh after February's winter storm, when it exceeded a threshold for too many hours at the limit as the ERCOT system struggled to meet soaring demand. By rule, the HCAP is set to revert to $9,000/MWh on Jan. 1.

"The overall objective is to reduce the HCAP before it resets in January to make sure people in Texas are not exposed to high prices when the calendar rolls over," PUC Chair Peter Lake said.

PUC Increases Gas Coordination

Facing Wednesday's statutory deadline to issue orders addressing the storm's damaging aftereffects, the PUC approved a *proposal* to increase coordination between the electric and gas industries during an energy emergency (*52345*).

The rule requires critical natural gas facilities to share "critical customer" information to electric utilities, who then must incorporate the information into their load-shed and power-restoration plans by prioritizing natural gas. It applies statewide. ERCOT manages about 90% of the state's grid, but staff have assured SPP and MISO that the rule will not conflict with their FERC jurisdiction.

"We want it to be clear they need to be collecting this information and implementing it to the extent they can, but it's not going to impede their FERC obligations," the commission's David Smeltzer said.

The Texas Railroad Commission (RRC), which provides oversight of the state's natural gas and oil industries, also passed a companion *rule* Nov. 30 that requires gas companies prepared to operate during an energy emergency to file necessary forms with regulators.

Those companies that tell the RRC they aren't prepared to operate during an emergency will have to explain why they can't and pay a $150 fee. The rule tightens the commission's original proposal, which would have allowed facilities to opt-out of weatherization requirements by simply paying the $150.

"These requirements represent a fundamental change in the relationship between the natural gas industry and the electric generation industry," Lake said. "For the first time ever, the electric transmission and distribution utilities will know the locations of the facilities which are critical to keeping natural gas flowing to the power plants that keep our lights on."

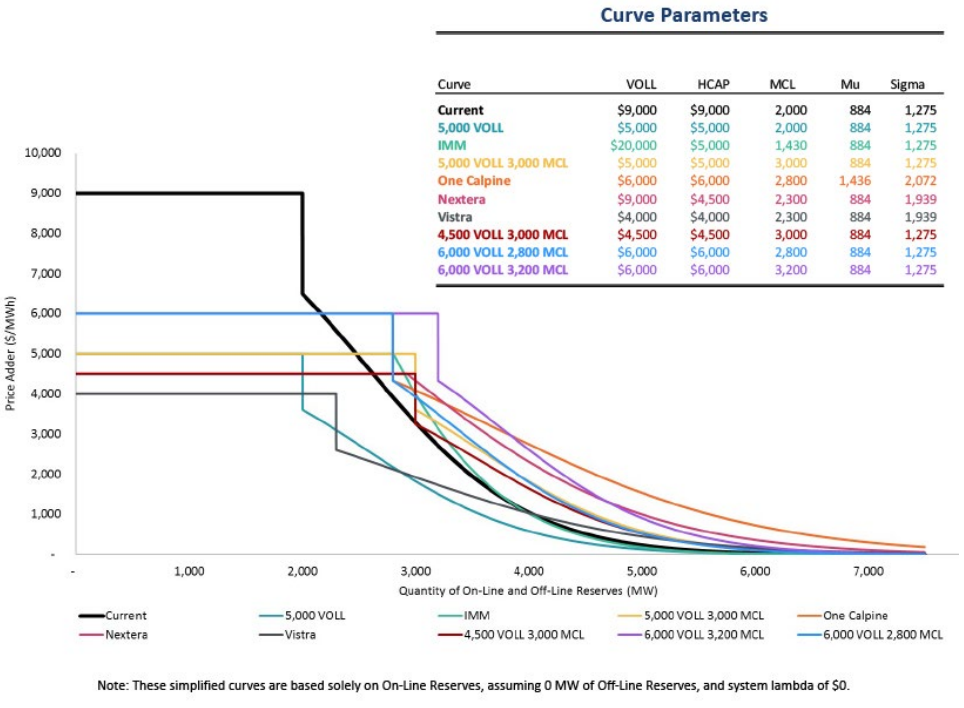
Lake noted that more than 700 gas facilities have identified themselves as critical, up from the 10 or 15 before the storm.

During the RRC's open meeting, Chair Wayne Christian took aim at the criticism the agency has faced in recent weeks. *The Houston Chronicle* has urged the RRC's three commissioners *to resign* for "[misleading] Texans about the causes of the deadly blackouts" caused by the storm.

Despite FERC's and NERC's joint report that fingered the lack of natural gas and other fuel supplies as the main culprit behind the widespread outages, Christian said laying the blame on gas producers was "pure hyperbole." (See *FERC, NERC Release Final Texas Storm Report*.)

The PUC also approved a *rule* requiring ERCOT market participants to update and file emergency operations plans with the commission and to participate in drills to test the plan once the State Operations Center is activated (*51841*).

The rule is a result of legislation passed by Texas lawmakers earlier this year. Stakeholders have a Jan. 4 deadline to file comments on the proposal. ■



ERCOT's operating reserve demand curve will soon be changing again. | *The Brattle Group*

ERCOT News

OGE, CenterPoint Complete Enable's Disposal

Energy Transfer Partners Acquires Partnership in $7.2B Deal

OGE Energy and CenterPoint Energy said last week that midstream energy company Energy Transfer Partners has completed its acquisition of their Enable Midstream Partners gas-gathering partnership.

The $7.2 billion all-equity transaction was announced in February. (See *Energy Transfer to Acquire Enable Midstream*.)

OGE, which owned about 79% of Enable's common units together with CenterPoint, will keep approximately 3% of Energy Transfer's outstanding limited partner units with the transaction's consummation. CenterPoint received about 201 million common units of Energy Transfer and $5 million in cash for its common units of Enable and general partner interest.

OGE CEO Sean Trauschke said in a *statement* that the acquisition "is an important step in OGE's plan to become a pure-play electric utility."

"We are now firmly on an accelerated path to reducing our exposure to the midstream industry," CenterPoint CEO David Lesar *said*.

Enable was created in 2013 by merging OGE's Enogex midstream subsidiary with CenterPoint's pipeline and field services businesses. OGE held a 25.5% limited partner interest and a 50% general partner interest in Enable; CenterPoint owned 53.7% of the common units representing Enable's limited partner interests.

In early 2020, OGE and CenterPoint took major earnings hits when Enable halved its quarterly distributions to investors and cut its capital expenditures for 2020 by $115 million. The cost reductions came during a global slump in petroleum demand and the COVID-19 pandemic. (See *Enable Losses Slam CenterPoint, OGE Energy*.)

Energy Transfer now owns and operates more than 114,000 miles of pipelines and related assets in all major producing regions in the U.S. and markets across 41 states. ■

— Tom Kleckner

Enable Midstream Partners processing plant | *Enable*

ERCOT News

ERCOT Technical Advisory Committee Briefs

TAC Finishes Wild 2021, Faces Uncertain Future

ERCOT's Technical Advisory Committee last week held its last scheduled meeting of a year that was upended by February's disastrous Winter Storm Uri.

The storm, which came close to collapsing the ERCOT grid, was linked to billions of dollars in damages and hundreds of deaths. It also resulted in political pressure and legislation that revamped the ISO's board, the regulatory commission, and the market's design, the latter of which has fallen partly on the stakeholder group to implement.

"What a year it's been," said South Texas Electric Cooperative's Clif Lange, the committee chair, during its Nov. 29 virtual meeting. "We've had quite a bit to tackle this year, and we have done some really good work and provided some good information and feedback to the ERCOT board and the commission, as necessary."

Despite the work, TAC faces uncertainty in its future. In July, interim ERCOT CEO Brad Jones discussed with the committee his plan to convert TAC into an officer-level group. During a candid conversation, Jones told members that if they didn't "think TAC is in the crosshairs, you're not paying close attention." (See *ERCOT Technical Advisory Committee Briefs: July 28, 2021*.)

Since that meeting, Jones' 60-point *roadmap to improving grid reliability* has updated his plans to note that TAC "has cancelled further discussion on this item until the new ERCOT Board and/or the [Public Utility Commission] initiate discussions on it."

Lange told the committee that the board will review TAC's processes and "make tweaks as necessary, while still retaining valuable input from the stakeholder process."

"We don't have any further guidance at this point on what further processes we need to review, but we'll continue to engage with the board as they deem fit," Lange told TAC's members.

Uri-related NPRRs Pass

TAC members approved four nodal protocol revision requests (NPRRs) related to operational actions and other measures taken as a result of the winter storm.

Stakeholders offered some pushback against staff's urgent measure *NPRR1105* allowing ERCOT to instruct transmission and/or distribution service providers (TDSPs) to deploy any available distribution voltage-reduction measures before declaring an energy emergency alert (EEA). The revision is the result of Board Chair Paul Foster's directive in October that TAC endorse the NPRR before the directors' December meeting.

"We do think this can be an effective tool in the right circumstances," Woody Rickerson, the ISO's vice president of grid planning and operations, said in addressing concerns that the revision will put the system in a weakened condition. "We would like to see this passed so we can use this tool, but we welcome additional conversation on this."

"It's a small arrow in the quiver. I think it's a wasted quiver," Advanced Power Alliance's Walter Reid said. "Hopefully, ERCOT will use this in a very judicious way."

Morgan Stanley Capital Group's Clayton Greer said he agreed with the NPRR's use to avoid rolling blackouts but said, "In this instance, we're not ever close to that level. We're taking pretty severe action when we don't even know whether there'll be [severe] conditions present."

Morgan Stanley and Demand Control 2 opposed the measure, which passed 23-2 with four abstentions.

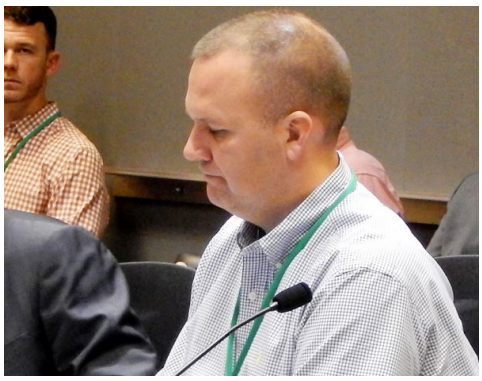
A second change (*NPRR1107*) adds new fees for ERCOT's weatherization inspections of the resource entity's capacity divided by the entity's aggregate capacity. Those inspections already have begun, with staff hoping to inspect about 300 facilities.

The NPRR also clarifies that existing generation interconnection or change request fees apply to all GI projects, regardless of whether they will interconnect at the transmission or distribution level. Those fees are $5,000 for projects less than or equal to 150 MW and $7,000 for projects greater than 150 MW.

Transmission service providers will pay $3,000 for each substation or switching station that is inspected.

"We would like to pay for the actual costs of our plants," said NRG Energy's Bill Barnes, who represents Reliant Energy Retail Services. He said lower costs for renewable resources "would be fair."

The measure passed without opposition, although independent generators Engie North America and Avangrid Renewables abstained.



TAC Chair Clif Lange, South Texas Electric Cooperative | © *RTO Insider LLC*

The committee also approved:

- *NPRR1103*, which establishes the processes for assessing and collecting default charges and default charge escrow deposits for the debt-obligation order securitizing about $800 million owed to the market by cooperatives and municipalities. (See "Securitization Orders Finalized," *Texas PUC Nears Market Redesign's Finish Line*.) ERCOT expects to begin issuing invoices in January.
- *NPRR1106*, codifying the grid operator's current practice of deploying emergency response service when physical responsive capability falls below 3 GW before declaring an EEA. The PUC ordered the new approach in October.

Staff to Seek Price Correction

ERCOT will request board review and a price correction for eight operating days in September and October after staff discovered a modeling error for a generation transmission constraint in the day-ahead market. Staff patched the defect by the end of surrender, but not before *determining* the Sept. 30 and Oct. 6-12 operating days met the criteria for a price correction from the board.

Staff's resettlements of the error resulted in more than $816,000 in increased charges and more than $122,000 in reduced charges to market participants.

The board will take up the issue during its meeting Friday.

Lange Honors John Dumas

TAC is short one member heading into 2022

ERCOT News

following the recent death of the Lower Colorado River Authority's John Dumas in November. Dumas, long a fixture in ERCOT circles and with more than 28 years of experience in managing electric grids and wholesale market operations, was one of four cooperative representatives.

"He was a great person to know. Very congenial and always willing to talk," Lange said. "He contributed an extraordinary amount to the ERCOT market and the reliability of the system over his career. His influence on the ERCOT region will persist for quite a few years to come."

Dumas joined LCRA in 2015 as vice president of market operations. Previously, he was with TXU, Vistra's predecessor, before joining ERCOT in 2008 as manager of operations planning and then director of wholesale market operations.

Annual Membership Meeting Friday

Staff said ERCOT's *annual membership meeting* will be held virtually on Friday. In lieu of the usual guest speaker, Jones and Foster will both deliver short comments. The *2022 TAC members*, currently comprised of familiar faces, will also be announced during the 30-minute session.

The meeting will follow the board's December meeting, which will be held in-person in Taylor. The directors will meet in executive session Thursday before holding an open session Friday morning. ERCOT's Austin headquarters building is closed to meetings during the transition to a new nearby facility.

In-person stakeholder meetings are expected to resume in January, beginning with TAC on Jan. 26. ERCOT's new headquarters workspace is expected to be ready by then.

TAC Endorses $1.28B Tx Project

TAC's combination ballot, which passed unanimously, included the endorsement of a $1.28 billion dollar transmission project put forward by the Regional Planning Group. (See *ERCOT Finds 345-kV Solution for Valley Constraints*.)

The project would add 351 miles of transmission lines radiating from a new substation in the Lower Rio Grande Valley, where ERCOT and the PUC have identified an urgent need for more transmission capacity. The commission in September exerted its new-found regulatory muscle in bypassing the stakeholder process and directing three utilities to add a second 345-kV circuit to an existing transmission line in the valley. (See *Texas PUC Directs Tx Construction in Valley*.)

LCRA's John Dumas during a 2019 conference panel discussion. | © *RTO Insider LLC*

The combo ballot also included endorsement of ERCOT's proposed 2022 ancillary service methodology. Staff recommended one change in computing minimum responsive reserve service (RRS) requirements by using a floor of 2.8 GW to meet the grid's more conservative operations approach. They also proposed changing the minimum RRS-primary frequency response limit to 1.24 GW, based on NERC's updated BAL-003 Interconnection Frequency Response Obligation assessment for next year.

The combo ballot also included five NPRRs, two Nodal Operating Guide revisions (NOGRRs), a pair of other binding document changes (OBDRRs), a revision to the Planning Guide (PGRR) and two modifications to the resource registration glossary (RRGRRs).

Members approved separately a revision request (*NPRR1109*) that allows a resource entity to bring a decommissioned generating unit back to service if it notifies ERCOT within three years of its removal from the network operations model. The measure passed by a 21-2 margin with six abstentions.

- *NPRR1077*: expands *NPRR1026*'s self-limiting facility concept to include sites with one or more settlement-only generator (SOG) and introduces additional revisions to fully address requirements for generators and energy storage systems (ESSs) connected at distribution voltage. The NPRR requires the SOG's qualified scheduling entity to provide telemetry of the injection or withdrawal at the point-of-interconnection (POI) for transmission-connected sites or point-of-common coupling for distribution-connected sites.
- *NPRR1091*: addresses energy-price suppression and liquidity issues created by ERCOT's early and greater procurement of ancillary service by extending the treatment of must-take energy from reliability unit commitments in pricing run to offline non-spinning reserve (non-spin), when it is manually deployed. The change also increases the amount of responsive reserve and non-spin services that an entity can self-arrange above its obligation.
- *NPRR1094*: allows a transmission operator (TO) and a transmission and/or distribution service provider (TDSP) to manually shed load connected to under-frequency relays during an energy emergency alert (EEA) Level 3 if the affected TO can meet its overall under-frequency load shed (UFLS) requirement and its load shed obligation under the Nodal Operating Guide.
- *NPRR1101*: modifies load resources' deployment grouping requirements if they're not controllable load resources ("NCLRs") providing non-spin to include generation resources providing offline non-spin.
- *NPRR1104*: corrects the definition of real-time liability extrapolated (RTLE) to include market activity for entities that have no load or generation but do have real-time exposure.
- *NOGRR231*: updates ERCOT's regional map in Section 1.1 to reflect the current boundaries.
- *NOGRR233*: allows a TO and a TDSP to manually shed load connected to under-wfrequency relays during an EEA Level 3 if the affected TO can meet its overall UFLS requirement and load-shed obligation.
- *OBDRR034:* provides ERCOT with the authority to move network operations model resource nodes for POI changes or resource retirements.
- *OBDRR035:* aligns the non-spinning reserve deployment and recall procedure with NPRR1101's revisions.
- *PGRR092:* allows an interconnecting entity (IE) proposing a SOG to designate it as part of a self-limiting facility during the generator interconnection or modification (GIM) process, consistent with NPRR1077.
- *RRGRR029:* allows an IE proposing a SOG to designate it as part of a self-limiting facility during the GIM process.
- *RRGRR030*: removes voltage levels' hard coding for certain resource registration information related to transformer data, allowing resources connected to other voltage levels to submit their data without receiving a validation error. ■

— Tom Kleckner

ISO-NE News

ISO-NE: New England Could Face Load Shed in Cold Snaps

By Michael Kuser and Rich Heidorn Jr.

Limited natural gas pipeline capacity and global supply chain issues with oil and LNG put the New England grid at heightened risk of emergency actions — including controlled outages — this winter, ISO-NE CEO Gordon van Welie told reporters Monday.

The RTO anticipates having adequate capacity to meet forecast peak demand of 19,710 MW during average winter weather conditions of 10 degrees Fahrenheit and 20,349 MW if temperatures reach below-average conditions of 5 F, with both projections about 2% lower than last year's forecasts.

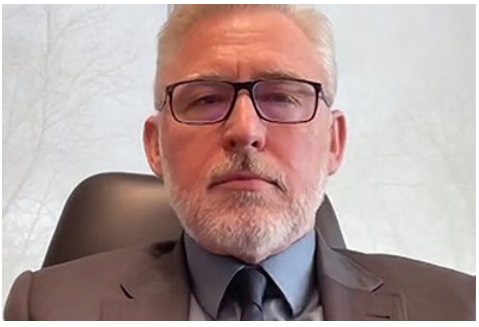
The National Oceanic and Atmospheric Administration this year is projecting a warmer than average winter in New England. "If this forecast holds true, and we hope it does, the ISO expects to have the resources needed to meet consumer demand throughout the winter season," van Welie said during a press briefing.

But he said uncertainty over fuel supplies "could put the region in a more precarious position than past winters and force the ISO to take emergency actions up to and including controlled power outages. These controlled power outages would be a last-resort action to prevent a regionwide blackout, which would take many days or weeks to restore."

Risk Factors

Van Welie said three variables will impact the RTO's ability to provide adequate electricity: natural gas supplies, always tight in winter because of competing heating demand; the availability of oil and LNG; and "weather events becoming more frequent and more extreme."

He noted that current storage levels of oil and LNG are lower than in recent winters and that European and Asian LNG prices are now as much as double those in New England.



ISO-NE CEO Gordon van Welie | *ISO-NE*

"If you were a supplier of LNG, where would you send your cargoes? To Europe or Asia or New England? I mean, I think the answer is pretty obvious," he said. "In past winters, we've had the reputation of being the highest-priced gas market in the world, and so there was a really strong financial incentive to send LNG cargoes to New England. That dynamic has flipped for this winter."

Need to Communicate with Public

Peter Brandien, vice president of system operations and market administration, said the RTO is planning for the winter based on what it learned from the cold spell of 2017/18 — when all major cities in New England had average temperatures below normal for at least 13 consecutive days, despite the forecast of a mild season — and the recent load sheds in California and Texas.

Brandien noted that CAISO had to shed load during a heat wave because it ran out of energy as the renewables "ramped out."

"After they shed load, and then communicated the tight situation that they were in, they ended up getting about 3,000 MW of additional capacity that they did not realize was available to them. When people really understood the situation, they got a lot better conservation than they had leading into the event," he said. "So part of what we're trying to do here is really educate everybody on where we are and understand that when we do go out for conservation, we're going out for conservation to try to keep everybody with electricity and try to head off" load sheds.

Van Welie said there were also lessons from the outages in Texas during the February winter storm, although he emphasized "our system is better winterized, meaning the power plants, transmission lines and other equipment needed to produce and deliver electricity can better withstand cold temperatures." (See *FERC, NERC Release Final Texas Storm Report*.)

"Watching what played out in Texas, and realizing that most people in this region don't understand how vulnerable we are when it gets cold, we thought that it's time for us to start communicating more openly about these risks," he said. "We're not trying to panic anyone; we're not trying to cause undue alarm. We need people to understand how vulnerable it can be under the wrong set of conditions, and that this region hasn't yet solved this problem."

The New England region depends on natural gas as the balancing energy source, using gas to produce 50 to 60% of its electrical energy today.

"And yet we know we have this constraint in the winter, so we turned to burning imported gas, essentially LNG, or imported oil, so the question is how do you start displacing that?" he said.

Siting Woes, EE

Van Welie said some technological solutions, such as small modular nuclear reactors, would be unlikely to win siting permission in New England.

The region also has not yet taken other mitigating measures such as increasing the imports of hydroelectricity from Quebec. Van Welie said he was "disappointed" with the inability to complete the New England Clean Energy Connect (NECEC) transmission line, which would deliver hydropower from the province to Massachusetts.

The project's developer last month halted line construction, and Maine regulators suspended its environmental permit after Gov. Janet Mills certified a negative referendum vote and asked the company to stop work. (See *NECEC Halts Tx Line Construction, Regulators Suspend Env. Permit*.)

"If it doesn't go ahead, I think we'll find other paths," van Welie said.

The region is going to have to spend more in order to get transmission landlines sited because people don't want to see such lines, but burying them incurs a much higher cost, he said.

New England is spending more than $1 billion a year on energy efficiency, which has dramatically clipped the growth in electricity usage in the region. But the wave of electrification coming will add more demand to the grid, he said.

"I think we will continue to need to do both energy efficiency as well as look to solve for the supply side of the equation," he said.

Van Welie said the region may need to consider adopting something like the two-week energy reserve he's seen in the Nordic countries.

"I think that's a discussion to be had," van Welie said. "It's probably some combination of the LNG, imports from Hydro-Quebec, [and] in-region storage of LNG and oil. Then the big question will be how do we get off the fossil fuels? What do we replace the fossil fuels with? Because it cannot be the answer in the long run." ■

ISO-NE News

NEPOOL Participants Committee Briefs

Tx Planning Tariff Changes Approved

ISO-NE stakeholders Thursday approved *tariff changes* that incorporate a new transmission planning process focused beyond the RTO's current 10-year planning horizon.

The revisions, which the NEPOOL Participants Committee passed unanimously with one abstention, are part of a multiphase effort. The initial phase establishes the rules to enable the New England States Committee on Electricity (NESCOE) to request that the RTO perform longer-term, scenario-based transmission planning studies on a routine basis.

The present processes do not support state-requested transmission analysis based on state-developed scenarios, inputs and assumptions. The new approach includes the development of high-level transmission concepts and cost estimates, if requested, to meet the state-identified requirements.

The second phase, to begin in early 2022, will address the rules to enable NESCOE to consider potential options for addressing the identified issues and cost allocation for associated transmission improvements.

2021-2022 Winter Outlook

ISO-NE COO Vamsi Chadalavada *presented* the region's 2021-2022 winter outlook during his monthly report, with the 50/50 and 90/10 winter peak demand forecasts both lower than last winter's.

The 50/50 forecast of 19,710 MW is 456 MW (2.3%) lower, while the 90/10 forecast of 20,349 MW is 2.2% lower (457 MW). Chadalavada said that if this winter is similar to the last, the RTO anticipates reliable power system operation without the need for emergency procedures. It is assuming no significant generation or transmission outages and limited fuel replenishment in this profile.

Energy Market Value Falls

Chadalavada *added* that ISO-NE's energy market value for last month (through Nov. 22) was $375 million, down $185 million from October but up $130 million from last November.

Natural gas prices were 6.1% higher than in October, while gas prices and LMPs were up 154% and 112%, respectively, over the same period last year. Average day-ahead cleared physical energy during the peak hours as a percentage of the forecasted load was 98.6% during November, down from 99% during October, with the minimum value for the month of 93.9% posted Nov. 22.

Daily uplift, or net commitment period compensation (NCPC) payments, in November totaled $2.5 million, down $1 million from October, though $600,000 higher from November 2020. NCPC payments were 0.7% of the energy market value.

Two projects totaling 213 MW were added to the interconnection queue since Chadalavada's last update. They consist of one battery project and one solar project, and each has in-service dates of 2024. In total, 300 generation projects are currently being tracked by the RTO, totaling approximately 31,947 MW.

2022 Budget

The PC *unanimously approved* — with abstentions — a 2022 budget of $6,587,000 for NEPOOL,

Central Maine Power

up more than $350,000 from 2021's spending plan. However, NEPOOL expects to spend $5,974,600 by the end of this year, $246,000 less than the 2021 approved budget.

The decrease mostly comes from declining committee meeting expenses amid the COVID-19 pandemic, as all gatherings were virtual events until October. Budget increases for 2022 include an increase in committee meeting expenses to $725,000, up from an approved figure of $510,000 in 2021 and 10 times the current forecast of $75,000.

Cavanaugh Re-elected Chair

PC Chair David Cavanaugh, vice president of regulatory and market affairs for Energy New England, was *re-elected* for 2022. Vice chairs were also re-elected include Tina Belew of the Massachusetts Attorney General's Office; Frank Ettori, Vermont Electric Power Co.; and Michelle Gardner, NextEra Energy. Sarah Bresolin of ENGIE North America and Aleks Mitreski of Brookfield Renewable Energy Group were also elected vice chairs. ■

— Jason York

ISO-NE News

Clements: FERC, States Need to Work Together

By Jason York

FERC Commissioner Allison Clements | © *RTO Insider LLC*

FERC Commissioner Allison Clements told the ISO-NE Consumer Liaison Group on Wednesday that the country's energy sector is facing a "system challenge" from a rapidly changing resource mix that requires intelligent transmission planning and investment as part of the energy transition.

Any system problem needs a system solution, said Clements, who is focusing on ensuring that the commission and states work together "to embrace the full portfolio of solutions to unprecedented and formidable challenges."

Clements said there is a "once-in-a-generation opportunity" to invest in new transmission that can contribute to cost-effective and reliable facilitation of a changing resource mix. When asked about the uncertainty surrounding the New England Clean Energy Connect (NECEC) transmission line, which would supply hydropower from Hydro-Québec to the New England grid through a 20-year supply agreement with Massachusetts utilities, Clements called it a "clear example" of the challenges related to siting new transmission.

On a subsequent panel, Michael Giaimo, Northeast regional director for American Petroleum Institute, said policymakers should not be so quick to retire existing fossil fuel infrastructure.

"My parents taught me that if you leave a job, make sure you have another job," Giaimo said. "So, the analogy here is if you want to ensure a reliable power system at a minimum, you shouldn't retire infrastructure until you are certain."

Given New England's policies intended to stimulate solar, wind and electrification, Giaimo said the region needs to have resources in times when renewables aren't available and to account for the increase in nightly load for electric vehicle charging and residential heating. Additionally, he said, it's essential to consider that existing gas infrastructure can help facilitate low-carbon fuels, like green hydrogen, in the future.

Dale Bryk, director of state and regional policies at the Harvard Environmental and Energy Law Program, said the region "can't say 'no' to things when we don't have a plan."

"But we also can't use the absence of a plan as a weapon to prevent ever changing anything," Bryk said. "We have to stop digging the hole and stop investments in fossil fuel infrastructure that we know we have to abandon and build the solutions in a timely way so that we do have a just, equitable and orderly transition."

"This transition is happening," Clements said. "It's not the commission's job to plan it. It's the commission's job to facilitate it and protect customers and contribute to the assurance and reliability while it's happening. That's exciting. It's like we're the underlying nuts and bolts that are allowing the implementation to take place." ■

MISO News

MISO Market Subcommittee Briefs

Stakeholders Surprised at Integrated Roadmap Changes

MISO plans to revise its *Integrated Roadmap* process, the ongoing five-year workplan that prioritizes and tracks progress on market improvements.

The grid operator is doing away with a stakeholder ranking of improvements. Additionally, it will now accept suggestions for improvements on RTO operations year-round instead of imposing an annual deadline. MISO usually closes a submission window late in the year and begins prioritizing issues early the following year.

Stakeholders attending Wednesday's Market Subcommittee meeting said they weren't notified that MISO would change the process so dramatically. They said staff should have approached them during earlier subcommittee meetings to discuss the change before their announcement.

MISO's head of stakeholder relations, Bob Kuzman, said executives will deliver a more in-depth briefing on the changes during next week's Board Week.

Low Numbers for New Member Interface

MISO customers are slowly migrating to the new market user interface. Only 24 of 294 customers have fully migrated to the new system, with another 86 in the process.

"We are making very slow progress towards the migration," said Arijit Bhowmik, MISO director of real-time applications.

The RTO's revamp of is market interface — where participants submit bids and offers — is part of its market platform replacement.

MISO will retire its legacy system on Jan. 18. It began a four-month parallel operations phase on Sept. 8.

MISO's short-term reserve product, which is set to go live on today, relies on the new market user interface. Short-term reserves are meant to supply energy within 30 minutes.

MISO: Member Privacy Trumps Zonal Data Sharing

In responding to stakeholders' requests for access to seven-day load forecasts in their local balancing authority or resource zones, staff said they could publish weekly load forecasting data, but only on a subregional basis.

MISO's Congcong Wang said the RTO has a few local BAs that rely on just one or two suppliers. Divulging load data for those areas would display confidential information, she said.

MISO control room | *MISO*

Wang said staff can share its load data broken down to MISO South and the North and Central portions of MISO Midwest.

Some customers have asked for access to seven-day load forecasting data at the local BA or local resource-zone levels. (See "Tx Customers Ask for Additional Load-forecasting Data," *MISO Market Subcommittee Briefs: Oct. 7, 2021*.)

Most RTOs make load forecasting data for the coming week available to their members, though the level of detail varies. ■

— Amanda Durish Cook

MISO News

Michigan ROFR Bill Approved, Sent to Governor

By John Lindstrom

LANSING, Mich. — Legislation granting incumbent transmission owners the right of first refusal to build and operate transmission lines in Michigan is on its way to Gov. Gretchen Whitmer (D) for signature after winning final legislative approval.

SB 103, which would benefit ITC Holdings and American Transmission Co., was sent to Whitmer by the Michigan Senate Thursday after the House approved the bill in a 71-29 vote late Wednesday.

Whitmer's administration has said nothing about the legislation, which had bipartisan sponsors, including Democratic Sen. Curtis Hertel Jr., who succeeded Whitmer in the Senate. It was opposed by only a few Democrats.

Most of the 29 opponents in the House were the most conservative of the majority Republicans. The most conservative Republicans opposed the bill in the Senate, which is also controlled by Republicans.

The bill was unchanged by the House from the version passed in the Senate in October. (See *Mich. Senate OKs Transmission ROFR for Incumbent TOs*.)

The bill would apply to "regionally cost-shared" transmission projects, such as those resulting from *MISO*'s Transmission Expansion Plan. It takes advantage of the exception under *FERC* Order 1000 that allows states to create a ROFR. The order prohibited such rights in tariffs filed with the commission in a bid to create competition, although some incumbents have recently urged FERC to reverse the prohibition in the commission's Advance Notice of Proposed Rulemaking proceeding. (See *FERC Tx Inquiry: Consensus on Need for Change, Discord over Solutions*.)

With the legislature pushing to finish the 2021 session this week, the House Energy Committee reported the bill on Tuesday, and it was rushed through its final readings on the House floor before passing. There was no debate on the bill in the House.

ITC Holdings calls itself the largest independent electric transmission company in the U.S., with projects in operation or under development in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas, Oklahoma and Wisconsin. | *ITC Holdings*

ITC Holdings' ITC Transmission and Michigan Electric Transmission Co. serve most of Michigan's Lower Peninsula through a network of about 8,700 circuit miles. The companies have made $5.5 billion in capital investments in the state since 2003. | *ITC Holdings*

John Dulmes, executive director of the Michigan Chemistry Council, blasted the legislation, calling Michigan's electric costs a major barrier to attracting investments and jobs. "That's why it is disappointing to see today's vote to support the interests of a monopoly energy company instead of ratepayers. Our policymakers need to get serious about competitive energy policies and the high bills paid by our businesses and residents," Dulmes said in a statement.

The state's utility costs — some of the highest in the region — were cited as a reason Ford Motor Co. (NYSE:F) *announced* in September it was locating a major new electric vehicle factory in Tennessee.

The Chemistry Council was one of only a few vocal opponents to the bill. The measure was backed by as many as a dozen groups, including labor groups and the Michigan Chamber of Commerce.

When the bill passed the Senate, the chief sponsor Sen. Wayne Schmidt (R), said the state's efforts to reduce carbon emissions through electrification will require more transmission in the state. The bill will help ensure a more orderly system to develop transmission, he said.

Whitmer will have 14 days to sign or veto the measure once she receives the proofed and printed version of the bill. ■

MISO News

MISO Modifies Stakeholder Meeting Schedule

By Amanda Durish Cook

MISO has scrapped its plan for a meeting schedule that would have packed all major stakeholder meetings into a single week eight times per year.

Instead, the grid operator will stagger eight meetings of its main stakeholder committees across the year, alternating between in-person and virtual formats. The modified schedule still will have MISO holding fewer stakeholder meetings throughout the year.

The RTO said in September that it planned to squeeze all stakeholder meetings of its main parent entities into eight separate weeks over the year, creating "superweeks" consisting of all-day meetings. The new calendar was to take effect next year. (See *MISO Wants Abridged Stakeholder Meeting Schedule*.)

MISO defines its main parent entities as the Market Subcommittee (MSC), Resource Adequacy Subcommittee (RASC), Reliability Subcommittee, Planning Advisory Committee, and Regional Expansion Criteria and Benefits Working Group, which makes cost-allocation decisions. The committees currently meet monthly in separate weeks dubbed as planning week, markets week and reliability week.

The grid operator's head of stakeholder relations, Bob Kuzman, said the new schedule will allow MISO to preserve its markets week and planning week.

"We heard your feedback, and we made a lot of changes to the proposal," he told stakeholders during Wednesday's RASC teleconference. "We heard that superweeks were going to provide too much information for stakeholders to digest."

In response, the RASC and MSC only approved the first five months of their 2022 meeting dates. The committees usually set a full calendar year of meetings during their December meetings.

RASC Chair Chris Plante said committee chairs will still have to make sure their workplans and goals will be able to fit into the new calendar.

Speaking on behalf of his company, WEC Energy Group, Plante said he was willing to give the new meeting frequency a try.

MISO client relations staff had framed the new meeting schedule as a transition to in-person meetings after two years of pandemic-induced isolation.

Kuzman said MISO will review the schedule with stakeholders in May to gauge its effectiveness. "This allows the face-to-face meetings as we get back to an in-person schedule."

He also said the new schedule will give staff subject matter experts respite between meetings to ready discussion points and meaningfully tweak proposals based on stakeholders' suggestions.

The February 2020 Resource Adequacy Subcommittee was one of the last meetings MISO held in-person. | © *RTO Insider LLC*

"MISO can get a little bit better prepared for the meetings, with better material and better answers to stakeholders' questions," Kuzman said.

The RTO had said the meetings' monthly pace was leaving staff in a cycle of preparing and delivering presentations, sometimes reciting information from identical slides across different committees.

The grid operator's first vision for pared-down in-person meetings proved unpopular with stakeholders.

In November, Plante said MISO should have consulted with stakeholder committee chairs to determine whether the groups could cover 12 months of agenda items across just eight meetings a year.

Plante also said there was probably a better way of limiting COVID-19 exposure between stakeholders and MISO staff. MISO said fewer in-person meetings might lessen the chances that someone contracts the coronavirus.

"I would have much rather seen us maintain the monthly meetings with an in-person meeting every other month," Plante said during a Nov. 4 MSC meeting.

"We were not approached about whether this would have been a good thing," MSC Chair Megan Wisersky said. "I'm concerned there wasn't enough stakeholder discussion outside of the Advisory Committee."

Wisersky also questioned whether the schedule should be provisional, adding that, "sometimes when MISO suggests something is temporary, it often becomes permanent."

Multiple stakeholders have also said change will relieve the pressure on staff to appear monthly and present market changes.

Wisersky, speaking as a representative of Madison Gas and Electric and not as a subcommittee chair, said she hoped MISO wasn't using the COVID-19 pandemic as a "guise" to disrupt the stakeholder process.

"It's not practical for us to block off an entire week for MISO meetings," WPPI Energy economist Valy Goepfrich said.

Kuzman has asked stakeholders to be patient while the RTO navigates a return to in-person meetings.

"We've all been separate." Kuzman said. "We miss the coffee talk; we miss the lunch talk." ■

MISO News

Entergy LA, NOLA Add Ida-related Debt

By Amanda Durish Cook

FERC last week authorized Entergy Louisiana and Entergy New Orleans to assume more than $15 billion in debt and securities to help recover losses incurred from Hurricane Ida's destruction (*ES22-7*, *ES22-8*).

The orders allow Entergy Louisiana to issue up to $13 billion in long-term debt, $450 million in short-term debt and $300 million in preferred securities. Entergy New Orleans can issue up to $1.24 billion in long-term debt, $150 million in short-term debt and $40 million in preferred securities.

FERC said the long-term interest rate cannot exceed 6.775% and the short-term interest cannot exceed 4.5%.

Additionally, the Entergy subsidiaries can also issue $170 million and $25 million in letters of credit to post collateral and secure their participation in MISO's markets.

Entergy said the late August hurricane inflicted anywhere from $2-$2.4 billion worth of damage to its Louisiana utility arm and $120-$130 million in damages to its New Orleans affiliate. The repair costs caused the utilities to surpass their debt ceilings ahead of their mid-July 2022 conclusion.

Entergy affiliates usually simultaneously file requests with FERC to issue debt, making the out-of-cycle requests unusual.

The new debt authorizations went into effect Dec. 1 and end Oct. 13, 2023.

Entergy reported damage to approximately 500 transmission structures, more than 225 substations, more than 210 transmission lines and nearly 6,000 transformers. Repairs to 30,500 distribution poles and nearly 36,500 spans of distribution wire were also necessary, the company said.

The staggering restoration costs led two commissioners to issue a warning of the increased financial damage related to climate change that ratepayers will bear.

FERC Chair Richard Glick and Commissioner Allison Clements wrote a separate concurrence urging their fellow commissioners to consider transmission investment as a means to hedge increasingly steep repair estimates.

Glick and Clements said while they agreed with Entergy's need to issue debt and securities, they were writing "to underscore that this is another clear example of the deep costs of climate change and extreme weather, which will ultimately be borne by customers."

The two pointed out that according to Entergy, the costs inflicted by Hurricane Ida were more than the combined costs of Hurricanes Katrina, Ike, Delta and Zeta.

"Hurricane Ida is just one of 18 climate-related disaster events with losses exceeding $1 billion that has affected the United States this year," Glick and Clements wrote. "We expect that restoration costs following climate-induced extreme weather events will continue to grow, and for that reason, the commission should consider how prudent investments in transmission system planning can ultimately save customers money."

Entergy Louisiana CEO Phillip May has rejected the idea that a more resilient transmission system could have withstood Ida's ravages any better than the existing grid. (See *Entergy Fends Off Calls for Tx, Solar, Microgrid Investment*.) ■

Damage from this year's Hurricane Ida in Louisiana | *Entergy*

MISO News

FERC Upholds ROE Refund Period for Mississippi TO

By Amanda Durish Cook

FERC last week said a MISO transmission owner cannot duck refunds stemming from the commission's recent decision to implement a 10.02% return on equity (ROE) for the grid operator's other TOs.

In a Dec. 1 order accepting the TOs' compliance filing for MISO's new ROE, the commission said Mississippi's Cooperative Energy cannot evade its refund obligation by shortening its refund period (*ER17-215*).

MISO's ROE has been a carousel of numbers for years. FERC in 2020 enacted a 10.02% ROE for transmission rates effective September 2016, superseding the 9.88% and 10.32% ROEs approved in 2019 and 2016, respectively. Those figures were intended at different times to replace the 12.38% ROE established in 2002, which FERC deemed excessive years ago. (See *FERC Stands by 10.02% ROE*.)

The TOs' compliance filings in question date back to 2016, reflecting the 10.32% ROE. FERC accepted them and ordered them updated to the TO's current ROE of 10.02%, including incentives not to exceed 12.62%.

But the docket's bigger point of contention came from Cooperative Energy, which argued that it shouldn't have to provide refunds for the full refund period FERC prescribed.

FERC ultimately ordered TOs to refund customers for the 12.38% ROE from Nov. 13, 2013-Feb. 11, 2015, and Sept. 28, 2016-Dec. 23, 2020. (See *MISO, TOs: More Time Needed for ROE Refunds*.)

Cooperative Energy argued that it wasn't obligated to issue refunds until mid-2015. That's the date it began receiving a 50-basis point adder for its participation in MISO, despite it having been a non-public utility TO in MISO and using the MISO ROE since December 2013.

Other MISO TOs bristled at Cooperative's interpretation of refund periods, leading them to register a limited protest of their own compliance filing.

FERC pointed out that Cooperative's RTO adder was conditioned on its agreement to provide ROE refunds should the commission lower the rate. FERC said the TO should use its 2013 entrance into MISO as its effective refund date.

The commission found Cooperative's arguments that forcing more refunds would amount to retroactive ratemaking to be baseless. ■

| © RTO Insider

MISO News

MISO to Test Long-range Tx Allocation Benefits

By Amanda Durish Cook

MISO has commissioned a study meant to demonstrate that long-range transmission projects built in the Midwest won't deliver benefits to the South.

The grid operator has tapped The Brattle Group to test its hypothesis that benefits from long-range projects built in either MISO Midwest or MISO South won't cross its subregional transmission constraint. Brattle is using hypothetical and past projects from MISO's 2011 Multi-Value Project portfolio to study a systemwide benefit spread.

The RTO plans to include the results in its FERC filing for a separate-but-equal postage stamp cost allocation that splits the system into MISO Midwest and MISO South for cost-recovery purposes. MISO hopes that the allocation will be temporary, and it plans to explore other long-range design options in 2022.

Speaking during a Dec. 3 Regional Expansion Criteria and Benefits Working Group, MISO's Jeremiah Doner said staff will share the study report with stakeholders when it's completed.

Some stakeholders asked whether MISO was deliberately creating a seam within its own borders with the first allocation design.

East Texas Electric Cooperative representative Paul Kelly said that some stakeholders already have performed analysis that show high-voltage, long-range transmission can deliver benefits systemwide despite the subregional transfer limit between the Midwest and South.

Stakeholders asked whether MISO would allow retroactive cost recovery in MISO South if Midwestern project benefits are shown to help the South and whether staff will again test for benefit flows once they finally recommend specific projects.

Currently, MISO won't estimate how much the first group of recommended projects could cost. It has said its first transmission planning scenario shows a need for upwards of $30 billion worth of projects, but those are expected over multiple years.

"I just can't help but ask … is there a plan in place if that scenario actually does show significant benefits to the South?" said Sam Gomberg of the Union of Concerned Scientists.

Construction of the MISO MVP Badger - Coulee line in Wisconsin | *IBEW*

MISO News

MISO's Aubrey Johnson said if study results show noteworthy benefits flowing to the South, staff would reopen cost-allocation discussions for the first Midwestern projects to emerge from the long-range transmission plan.

Johnson was asked whether MISO would then be unmoored on a singular cost-allocation design and propose allocation that could vary project-to-project or cycle-to-cycle. He said staff will not alter cost-allocation decisions once made but will use what it learns on benefits flowing Midwest to South to inform future allocation designs.

With the Brattle analysis, MISO once again delayed a FERC filing date for cost allocation, pushing it back from mid-December to mid-January. (See *MISO Schedules Cost-allocation FERC Filing*.)

The RTO's long-range transmission plan has evolved meeting-to-meeting, with postponements and temporary reductions in scale announced near-monthly.

The grid operator first told stakeholders it would advance an initial subset of projects based on its most conservative 20-year transmission planning scenario with December's approval of the 2021 MISO Transmission Expansion Plan. It then said it needed until March. Planners now say they won't have project proposals ready for a board vote until late spring. (See *MISO Postpones 1st Cycle of Long-range Projects*.)

MISO is not tackling Southern projects until sometime in 2023, leaving MISO South transmission needs out of the study's first cycle. Louisiana and Mississippi regulators have threatened to leave the grid operator if the first round of long-range projects' cost allocation extends to their utilities' ratepayers.

Stakeholders Tee Up 2022 Allocation Design Debate

Looking ahead to next year's debates on long-range cost allocation, MISO South members and regulators resubmitted for consideration their allocation proposal first presented in the summer.

The plan prescribes costs be directly assigned to project beneficiaries from either increased reliability, economic gains, or attained policy goals. It would have only states with decarbonization goals splitting project costs that further their clean energy aims. (See *Tensions Boil over MISO South Attitudes on Long-range Transmission Planning*.)

Clean Grid Alliance's Natalie McIntire said state goals that split transmission project costs are similar to MISO's current participant-funded project type, where market participants can construct a project so long as it doesn't harm the system. She said elements of the South proposal already are available as options in the MISO tariff.

Some stakeholders said the South proposal wouldn't pass at FERC because it proposes different allocation types for a single project class.

MISO's Environmental Sector countered the South proposal with a design that asks the RTO to incorporate all benefit metrics it has deemed acceptable, including improved public health from less pollutants. The sector also asked for a two-step cost assignment, with some costs assigned to the parties receiving quantifiable, economic benefits and the remainder spread evenly across a subregion to recognize the broad reliability benefits that high-voltage lines deliver but are difficult to calculate.

Sustainable FERC Project attorney Lauren Azar said the Environmental Sector's proposal clamps down on free ridership. She said her sector would also like to see benefits assumed over a 40-year horizon, noting most transmission remains energized for about 60 years, making projects undervalued when their benefits are initially measured.

MISO has said its system will not be able to function reliably in a future with a changing resource mix without new, large transmission projects (See *MISO Analyses Show Reliability Woes Without Transmission Builds*.) Currently, more than 95% of its members have carbon-emissions reduction goals.

Both MISO South regulators and Entergy representatives have questioned the amount of renewable penetration the RTO forecasts in future planning scenarios. They have suggested states with clean-energy goals pay a larger share of transmission construction costs.

The grid operator said it may need more than a dozen 345-kV additions, a handful of 500 kV and 765 kV lines, and even a massive footprint-wide network of DC lines as part of its the long-range planning package. (See *MISO Reveals Contentious Long-range Tx Project Map*.)

Based on MISO's annual MTEPs, the footprint could see more than 5,000 miles in new transmission lines come online over the next decade. Only about 200 miles of the new lines will be rated at 345-kV and greater.

MISO has not approved any large economic transmission projects since it changed their cost allocation in 2020. (See *MISO Cost Allocation Plan Wins OK on 3rd Round*.) The RTO had framed the new allocation as key to getting more Market Efficiency Projects approved. ■

NYISO News

NY Predicts 200K+ New Clean Energy Jobs by 2030

By Michael Kuser

A study commissioned by New York officials predicts that clean energy employment in the state will increase by at least 211,000 jobs this decade and by nearly 350,000 by midcentury.

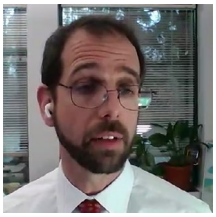
The preliminary *results* from the report by the Climate Action Council's Just Transition Working Group also finds that 10 new jobs will be created for every job displaced through 2030 by the state's move away from fossil fuels. The growth subsectors include electricity distribution and transmission, onshore and offshore wind, solar, battery storage, and the building and transportation sectors.

Philip Jordan, E3 | *NYDPS*

"That's really enormous job growth ... a rate that's more than double the annual growth rate from 2016 through 2020," Philip Jordan of Energy and Environmental Economics (E3), which conducted the study, told the council Nov. 30.

Drilling into Data

Following a growth rate of 15% from 2016 to 2019, energy efficiency jobs declined by nearly 5% with the advent of the pandemic but have been rebounding since the low point of the second quarter last year, according to the state's 2021 Clean Energy Industry Report recently *released* by the New York State Energy Research and Development Authority (NYSERDA).



Carl Mas, NYSERDA | *NYDPS*

At the end of 2020, there were approximately 157,700 clean energy workers in New York, and clean energy jobs comprised roughly 2% of all jobs in the state, but less than 1% of jobs lost in the economic downturn, said Carl Mas, director of energy and environmental analysis at NYSERDA.

Clean energy employment in New York a year ago was still about 12% higher compared to the 2015 baseline, Mas said.

Displacement of jobs could total 77,000 by midcentury, and the jobs study is intended to provide data to help officials develop workforce training and identify opportunities across the state, especially disadvantaged communities, Mas said.

One CAC member was surprised that the job growth isn't greater between 2030 and 2050.

Robert Howarth, Cornell University | *NYDPS*

"There's a pretty rapid increase until 2030, and then I would expect all sorts of actions need to be taken afterward, that they would increase it more," said Robert Howarth, professor of ecology and environmental biology at Cornell University.

The large job growth early on stems from the inputs given to the team, Mas said.

To hit the state's goal of 70% renewable electricity by 2030 requires "a massive level of investment in order to ramp up, and when we think about jobs, interestingly it's not the absolute amount of capacity; it's the annual scale of change that's driving jobs each year," Mas said.

Howarth also said that projected declines in gas station employment could be lowered by encouraging the creation of 440 fast-charge stations, which probably would feature cafes and convenience stores that would maintain the retail jobs.

Mas agreed and said that the scale of investments is starting faster than probably most analysts had expected five years ago.

"Because of that, we're driving job creation sooner and then sustaining those jobs over time as we retrofit more homes and as we build and deploy more solar panels," Mas said.

IPPNY CEO Gavin Donohue | *NYDPS*

Gavin Donohue, president and CEO of the Independent Power Producers of New York, asked if there was anything being done about non-energy manufacturing and job loss as a result of increased energy costs. The study talks about nuclear jobs being lost, but no licenses come up for renewal before 2029, he said.

The anomaly comes from the base year including the closure of the Indian Point nuclear station, Mas said.

"I understand that ... though we're talking about a decrease of use of natural gas as a state, but I didn't see a job impact and changes in other industries like agriculture or farming," Donohue said. "There has to be an impact in those sectors if we're having impacts in other sectors, so that's the question maybe we can answer later, but it's an omission on the study's part."

Moving Forward

NYSERDA CEO Doreen Harris | *NYDPS*

NYSERDA on Nov. 30 finalized contracts with Clean Path New York and with Hydro Quebec Energy Services for the Champlain Hudson Power Express and filed them for comment and approval with the Public Service Commission, council Co-chair and NYSERDA CEO Doreen Harris announced.

"All told these are the largest transmission projects contracted for in New York state in the last 50 years and will reduce the city's fossil fuel use for electricity by more than 80% in 2030 when combined with their other clean energy investments," Harris said. (See *Two Transmission Projects Selected to Bring Low-carbon Power to NYC*.)

The two separate projects total 2,550 MW and will bring solar, wind and hydropower south to New York City.

The CAC will meet in December to vote on a final draft scoping plan for achieving the goals laid out in the Climate Leadership and Community Protection Act, which will be discussed over the course of 2022 before implementation the following year.

NYSERDA will bring forward benefit-cost analysis at the next meeting, and will also be exploring a sensitivity around higher adoption rates for ground source and district heat pumps, Mas said.

Not every home and apartment in New York could adopt a ground-source system, so there would be a role for district heating that may be sourced by water or ground or other resources, Mas said.

"So we will be exploring that to give us some better insights into the technical feasibility and also some of those cost tradeoffs," he said. "While it may be more expensive to invest in these upfront, we also will see system benefits through a smaller grid." ■

NYISO News

NYISO Updates Grid in Transition Work and Plan for 2022

By Michael Kuser

NYISO on Thursday *updated* stakeholders on several market changes in the works to accommodate thousands of megawatts of state-solicited renewable resources coming online in New York over the next decade.

The measures range from carbon pricing and buyer-side mitigation to distributed energy resource participation models, including for storage, hybrid and co-located resources, all part of the ISO's Grid in Transition *initiative* announced two years ago, NYISO Principal Economist Nicole Bouchez told the Installed Capacity/Market Issues Working Group.

The ISO also posted the final *version* of its 2022 Master Plan for managing the changes in the energy, ancillary services and capacity markets.

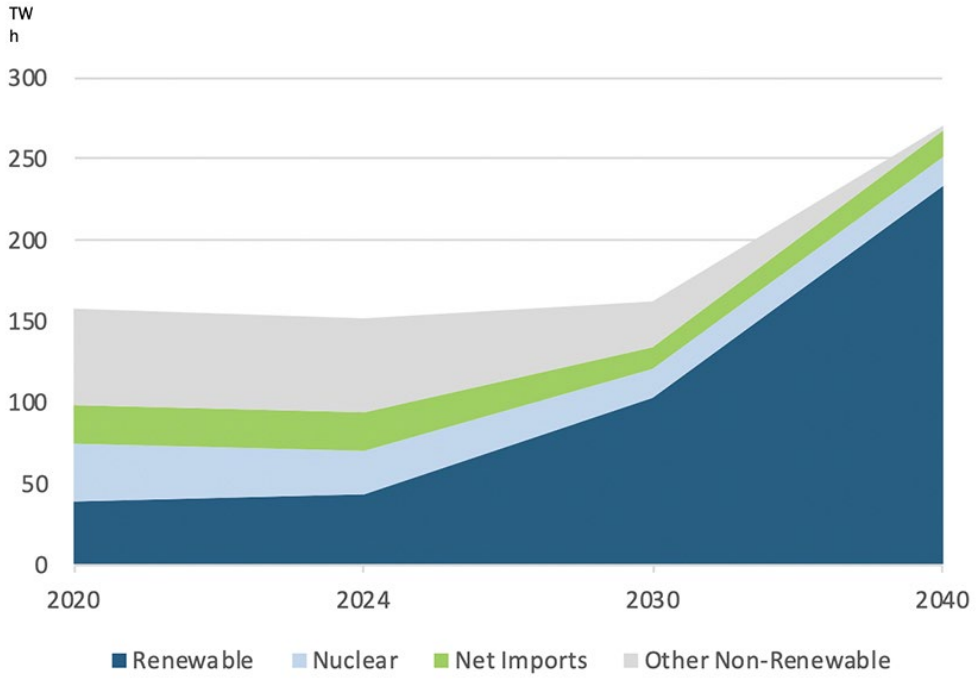
The state's Climate Leadership and Community Protection Act (CLCPA) and other statutes set ambitious clean energy targets staggered every five years from 2025 to midcentury, with strict emissions limits that regulators recently cited in denying air quality permits to two gas-fired generator proposals in the Hudson Valley and New York City. (See *NY Regulators Deny Astoria, Danskammer Gas Projects' Air Permits*.)

"This path of Grid in Transition is focused on market enhancements under three different areas, the first one being aligning competitive markets in New York with the state's clean energy objectives," Bouchez said. "The second one is valuing reserves for resource flexibility, and the third one is improving capacity market valuation."

NYISO retained The Brattle Group to forecast future resource mixes and help inform planning for reliability and market design over the next two decades, with the final report presented in June 2020. (See *'Astonishing' Buildout Needed for Clean NY Grid*.)

Stakeholders expressed concerns about how fast the ISO is able to incorporate new events and regulations into its capacity processes. For example, the gas-fired projects were turned down, but state agencies have approved two separate projects totaling 2,550 MW to bring solar, wind and hydropower south to the city, as well as offshore wind projects totaling 4,300 MW. (See *Two Transmission Projects Selected to Bring Low-carbon Power to NYC*.)

In addition to the projects proposed, the ISO also presented an update on leading indicator metrics, with the most recent *data* provided in September, Bouchez said.



New York's ambitious clean energy goals and a possible decarbonization path over the next two decades | *NYISO*

Supporting Studies

In looking at what changes to the markets are needed to face a growth in intermittent resource penetration, the ISO relied on several studies it has conducted over the past few years, including the following:

- *Power Trends 2021* (NYISO, May 2021)
- *Preparing the Capacity Market for the Grid in Transition* (NYISO, April 2021)
- *Climate Change Impact Phase II* (Analysis Group, September 2020)
- *New York's Evolution to a Zero Emission Power System* (The Brattle Group, June 2020)
- *2020 RNA Report* (NYISO, November 2020)
- *2021-2030 Comprehensive Reliability Plan* (NYISO, December 2021)

Aside from work on buyer-side mitigation tests and capacity accreditation, the ISO deployed a software-defined wide area network (SD-WAN). Separately, the NYISO is developing a billing and settlement system and billing simulator code. The remaining code for the DER participation model will be developed in 2022, with deployment also scheduled for next year.

The ISO expects to implement its hybrid co-located model in mid-December and will work to integrate the rules and software needed to enable large-scale weather-dependent and energy storage resources to participate as co-located resources (CSR) behind a single interconnection point. FERC in March accepted the ISO's rules allowing an energy storage resource to participate in the wholesale markets with wind or solar as a CSR, and NYISO has since been working on the market software. (See *FERC Approves NYISO Co-located Storage Model*.)

A regulation service project completed in September last year updated requirements, and the ISO will continue to monitor fleet changes and appropriately update statewide regulation procurement requirements in the future.

New Resource Integration

One critical area is related to new resource integration projects, Bouchez said.

She listed three: the DER participation model, the hybrid aggregation model — which is scheduled for a functional requirements specification in 2022 — and internal controllable

NYISO News

lines, "obviously something that we need to work through," she said.

The ISO anticipates starting to review the real-time market structure to start in 2025, "but we're thinking that it might not be a bad thing to start those discussions [next year] about the existing structure and different ideas for what changes should be considered and why," Bouchez said.

Reliability Risks

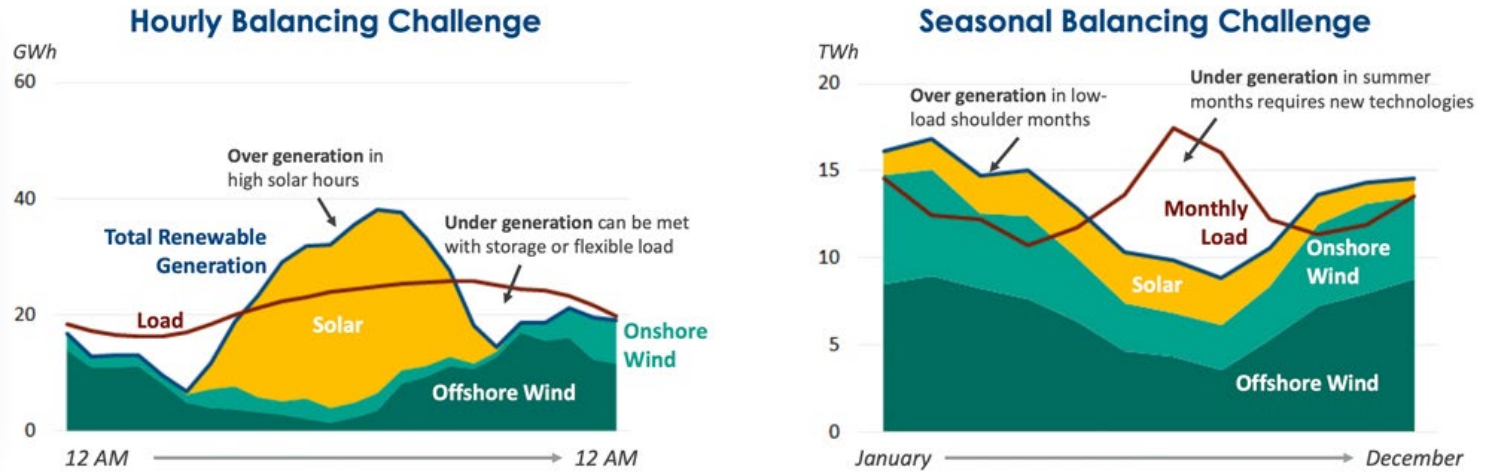
The ISO on Friday released its Comprehensive Reliability Plan (*CRP*), the culmination of the 2020-2021 Reliability Planning Process. The report concludes that the state's bulk power system will meet all applicable reliability criteria from 2021 through 2030 for forecasted system demand in normal weather.

But it also "demonstrates that our reliability margins are thinning to concerning levels beginning in 2023," Zach Smith, vice president of system and resource planning, said in a statement. "We have to move carefully with the Grid in Transition in order to maintain reliability and avoid the kind of problems we've seen in other parts of the U.S."

The CRP recommends monitoring and tracking transmission projects and other risk factors in order to mitigate risks to BPS reliability. In addition, system margins are expected to narrow to such a level that warrants review of current reliability rules and procedures.

NYISO said it will administer its short-term reliability process to address generator deactivation notices and other system changes on a quarterly basis, and continuously evaluate on a forward-looking, five-year basis.

"The potential risks to reliability identified in the analyses may be resolved by new capacity resources coming into service, construction of additional transmission facilities, and/or increased energy efficiency, integration of distributed energy resources, and growth in demand response participation," NYISO said. ■



The figure shows typical load profiles with typical generation profiles for wind and solar resources; while there may be enough energy overall to meet demand, it will be necessary to shift the generation from the afternoon to the morning and evening hours. | *The Brattle Group*

PJM News

FERC Declines Rehearing of PJM MOPR; Ball now in 3rd Circuit Court

FERC on Nov. 29 declined rehearing requests of its inaction on PJM's narrowed minimum offer price rule (MOPR) after a 2-2 tie vote, setting up further action in appellate court (*ER21-2582*).

The commissioner deadlock allowed PJM's proposal to automatically take effect Sept. 29 "by operation of law." The one-page notice from FERC last week said the rehearing requests "may be deemed to have been denied" in the absence of any action by the commission within 30 days of them being filed, indicating there has been no change in the stalemate.

Several PJM stakeholders, including the Electric Power Supply Association (EPSA) and the PJM Power Providers Group (P3), had filed requests. (See *MOPR Rehearing Requests Set Stage for Appellate Review*.)

The America's Water Infrastructure Act, signed into law by President Donald Trump in October 2018, added a provision to FPA Section 205 to allow for judicial review if FERC fails to act on the merits of a rehearing request within 30 days because the commissioners are divided 2-2. Having filed its request Oct. 5,

Pennsylvania wind turbines | *Shutterstock*

P3 *petitioned* the 3rd U.S. Circuit Court of Appeals early last month. (See *P3 Seeks 3rd Circuit Review of PJM MOPR*.)

Several parties have signed on to P3's petition, including EPSA, Calpine, LS Power and Talen Energy. Vistra and Exelon also filed separate petitions for review, which have been consolidated with P3's case. In a statement filed in the 3rd Circuit on Nov. 29, the petitioners said they intend to raise the issue whether FERC's order was "arbitrary, capricious or otherwise contrary to law."

PJM's narrowed MOPR is applied only to resources connected to the exercise of buyer-side market power or those receiving state subsidies conditioned on clearing the capacity auction. ■

— Michael Yoder

PJM News

FERC Reverses Course on Transmission Rights Resettlement in ComEd

By Rich Heidorn Jr.

Reversing course, FERC on Thursday ruled that PJM did not have to pay an Illinois wind farm $10 million under a resettlement of incremental capacity transfer rights (ICTRs) to the Commonwealth Edison locational deliverability area (LDA) (*EL18-183*).

ICTRs — available to interconnection customers that are required to fund a transmission facility — are awarded based on how much the improvement increases the transmission import capability into an LDA. ICTR holders receive revenues if the LDA in question is constrained in subsequent capacity auctions. The rights are good for up to 30 years.

The commission ordered the resettlement in April 2020 in response to a complaint by Radford's Run Wind Farm, which said PJM unfairly denied ICTRs for funding an upgrade identified in its system impact study (SIS) to mitigate a thermal overload on the 345-kV Loretto-Wilton Center line.

In a subsequent compliance filing, PJM determined that Radford's Run was entitled to almost $10 million for the 2019/20 delivery year. Crediting the wind farm required offsetting charges to the load-serving entities in the ComEd LDA associated with their corresponding CTR reductions. (See *PJM Announces $10M Resettlement in ComEd LDA*.)

In Thursday's order, however, the commission said it now concludes the wind farm wasn't entitled to ICTRs at the time of the 2016 Base Residual Auction for 2019/20.

Agreeing with challenges by PJM and Exelon's Commonwealth Edison, FERC said its earlier rebilling directive was "incompatible" with the PJM tariff's definition of ICTRs because the wind farm did not become "obligated to fund" its upgrades until after the 2016 BRA.

The commission said PJM's tariff is "ambiguous as it does not expressly state when the obligation to fund must occur."

It concluded that the tariff requires that the resource either execute an interconnection construction service agreement with collateral or reimburse the transmission provider for the costs of the customer-funded upgrades prior to the BRA to qualify for the ICTRs for the associated delivery year.

The 306-MW wind farm in Macon County, Ill., went into service in December 2017. Neither the wind farm's owner, RWE Renewables Americas, nor its attorney, Bruce Grabow of Locke Lord, responded to requests for comment.

PJM spokesman Jeff Shields said the RTO will comply with the order. "We don't have any further details at this time," he said. ■

Radford's Run Wind Farm | *E.ON*

PJM News

FERC Sets Hearing on Industrials' Challenge to PJM Administrative Rates

By Michael Yoder

FERC ordered hearing and settlement judge procedures Wednesday in response to industrial customers' protest of PJM's proposed revisions to its administrative rates (*ER22-26*).

The commission accepted PJM's proposed tariff revisions for filing and suspended them for a "nominal period" to become effective Jan. 1 while directing the appointment of a settlement judge within 45 days and the issuance of a report on the status of the settlement discussions 60 days after that.

FERC said its initial analysis found PJM's proposed tariff revisions may be unjust and unreasonable.

PJM's proposal called for changing its administrative cost recovery from the current practice of initial charges at stated rate levels with a varying quarterly refund to the new practice of monthly rates based on that month's costs and that month's billing determinations.

The RTO said the proposal was developed in conjunction with the Finance Committee and is "specific only" to schedule 9 of the tariff, which provides cost recovery for its subsidiary, PJM Settlement, Inc. The company provides billing, settlement, treasury and credit management functions for transactions in the PJM markets. Other schedules recover costs for FERC's annual charges, the Independent Market Monitor and other entities that benefit the PJM region.

The schedule 9 changes received unanimous support from the Finance Committee in July. PJM said the administrative rate review was initiated to examine "rate equity" across its membership to avoid cross subsidization among the different customer classes and for "overall revenue adequacy."

The proposal "adjusts with changes in usage patterns" of the services that PJM provides and the costs of providing the services; it was designed to avoid over- and under-collection of funds to finance the RTO.

Stakeholders endorsed the proposal and tariff revisions at the September Members Committee meeting. The proposal was endorsed with a sector-weighted vote of 3.84 (76.8%), and PJM made a filing with the commission on Oct. 1. (See "PJM Administrative Rates," *PJM MRC Briefs: Sept. 29, 2021*.)

Disagreements

The PJM Industrial Customer Coalition (ICC) protested PJM's filing, arguing that the proposal was "not supported by any quantitative analysis or evidentiary support, such as a cost-of-service study." The ICC said PJM did not provide any explanation for using the number of invoices as the new billing determinant for schedule 9, and that for industrial customers that have multiple accounts for multiple facilities in PJM, the "cost implications of the per invoice weekly charge is substantial."

The ICC said one of its members will see costs increase by 385%, while PJM "has not demonstrated that the cost to serve industrial customers with multiple accounts/invoices has uniformly increased by that kind of magnitude."

PJM said the "vast majority" of settlement costs are fixed expenses, "reflecting the resources PJM Settlement must secure to conduct its activities." The RTO said "more than half" of the ICC members were charged "little or nothing" under the current system.

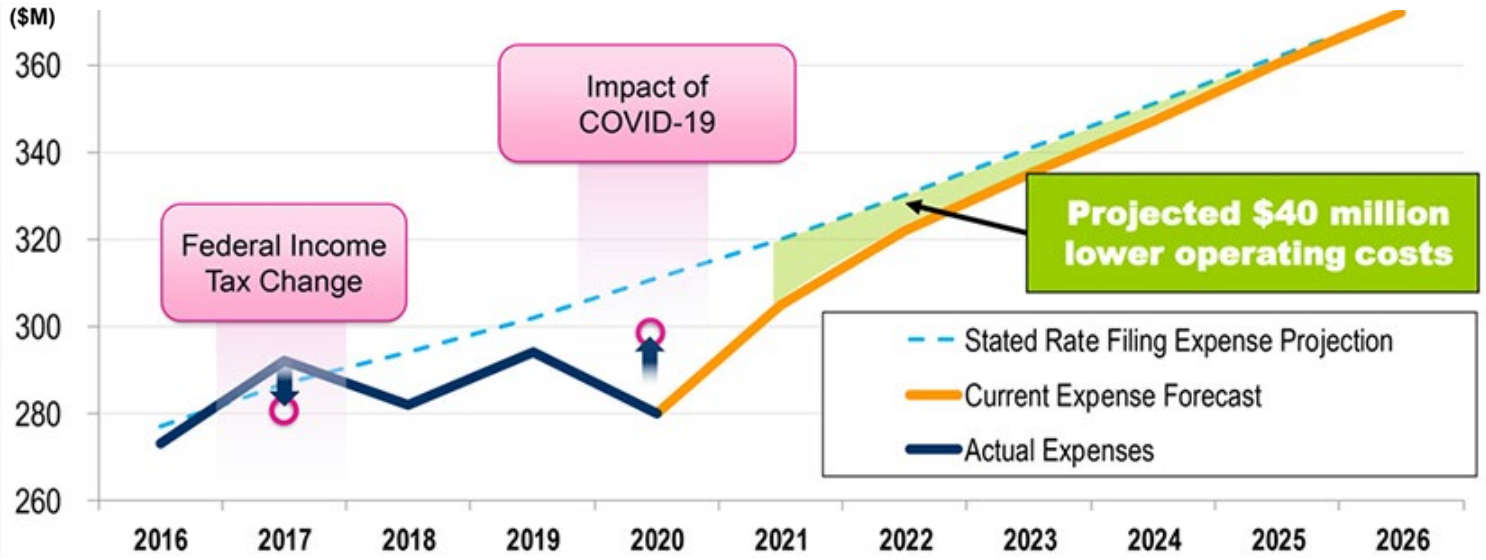
FERC said it needed fact finding to determine "whether PJM has justified its proposal to show that its per invoice approach comports with cost causation principles."

FERC Commissioner Allison Clements partially dissented to the order, saying she would have also set a hearing on whether PJM's cost transparency procedures are sufficient.

"Having previously participated in different RTO stakeholder processes, I appreciate the value of clarity in procedures related to ensuring transparency," Clements said in her dissent. "I am not convinced based on the record compiled to-date that the procedures outlined by PJM will prove adequate."

PJM last filed to update its administrative rates five years ago. In December 2016, FERC accepted PJM's proposal to increase its stated rates over an eight-year period, with a 7.5% increase in 2017 and a 2.5% hike annually between 2019 and 2024.

The RTO said it required the rate increase at that time because its stated-rate revenues had fallen below the level needed to recover its administrative costs. ■



PJM operating expense comparison with the stated rate filing projections versus the current forecast | *PJM*

PJM News

PJM TEAC Briefs

Transource Re-evaluation

PJM stakeholders received an update on Transource Energy's suspended Independence Energy Connection (IEC) transmission project at last week's Transmission Expansion Advisory Committee meeting.

Nick Dumitriu, PJM | © RTO Insider LLC

Nick Dumitriu, principal engineer in PJM's market simulation department, *provided* an update on the 2020/21 long-term market efficiency window, highlighting the suspended project in Maryland and Pennsylvania.

The Pennsylvania Public Utility Commission voted 4-0 in May to *reject* a series of related applications and petitions filed by Transource for lines in Franklin and York counties. The PUC denied the project based on concerns about whether the need established in the PJM planning process met the requirement for needs specific to Pennsylvania. (See *Transource Tx Project Rejected by Pa. PUC*.)

The PJM Board of Managers endorsed the RTO's recommendation to suspend the IEC project at its Sept. 22 meeting because of the "permitting risks" and to remove it from the pending Regional Transmission Expansion Plan models.

Transource's proposed alternative plan for the eastern segment of its Independence Energy Connection project | *Transource*

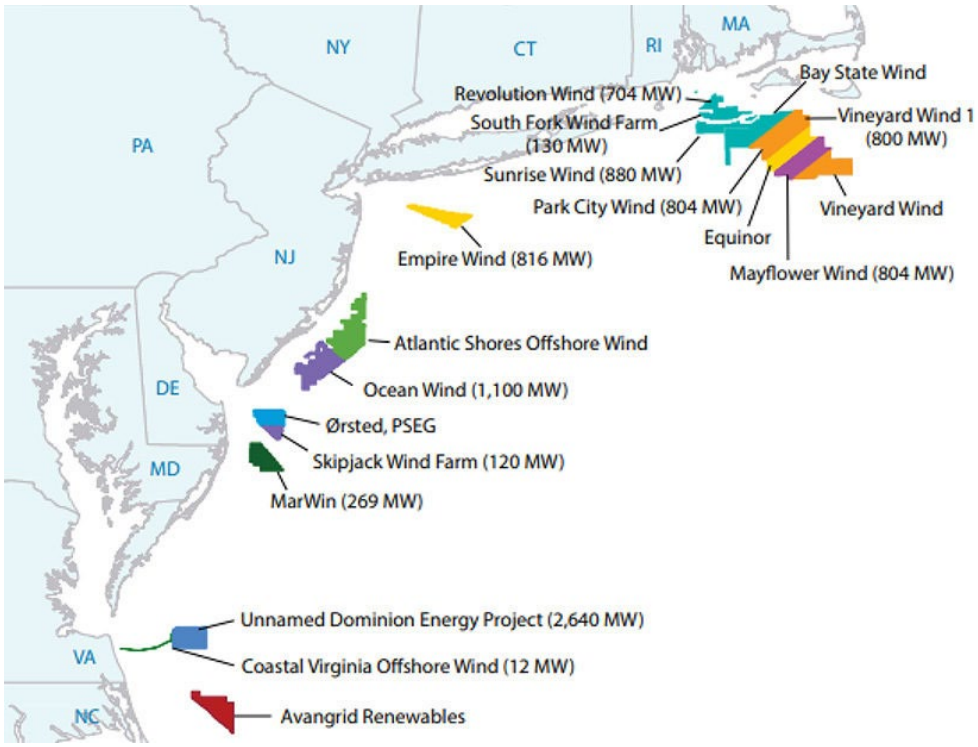
Dumitriu said PJM is required by schedule 6 of the Operating Agreement to "annually review the cost and benefits" of board-approved market efficiency projects that meet certain criteria to assure that a project continues to be cost beneficial. The annual re-evaluation is not required for projects that have started construction or have received state siting approval, and the Transource IEC was the only eligible project for 2021 re-evaluation.

Dumitriu said the base case analysis conducted by PJM yielded a benefit-to-cost ratio of 1.44, which excluded $131.88 million in sunk costs of incurred spending on the project. Dumitriu said that when the full in-service cost of $428.76 million for the project was analyzed, the benefit-to-cost ratio was 1.

The re-evaluation using a sensitivity scenario with higher load growth in PJM yielded a benefit-cost ratio of 2.08 with the exclusion of sunk costs and 1.44 for the full in-service cost.

A sensitivity scenario using additional coal retirements in the RTO yielded a benefit-cost ratio of 2 with the exclusion of sunk costs and 1.39 for the full in-service cost. Dumitriu said Talen Energy announced that its Montour generation facility in Pennsylvania and the Brandon Shores and H.A. Wagner coal generation facilities in Maryland, totaling more than 3,500 MW of generation, will cease coal-fired operations by the end of 2025 as the company moves toward renewable energy and battery storage projects.

Dumitriu was asked if PJM saw congestion growing on the AP South interface after removing the Transource IEC project. He said there are changes in congestion patterns after removing the IEC and that PJM sees "increasing congestion" on all the nearby constraints.



New Jersey is preparing to be a manufacturing and operational hub for wind projects up and down the East Coast. | *AWEA*

PJM News

NJ OSW Projects

Aaron Berner, PJM | © RTO Insider LLC

Work continues on proposals to interconnect New Jersey's offshore wind projects through the 2021 state agreement approach window. Aaron Berner, PJM senior manager, *provided* an update on the 2021 RTEP analysis.

Berner said the proposals, which were presented at the October TEAC meeting, have been posted on PJM's competitive planning *page* in redacted form. (See "NJ OSW Proposals," *PJM PC/TEAC Briefs: Oct. 5, 2021*.)

PJM is continuing to work through various analyses as part of the option 1a portion of the OSW window, Berner said, which included onshore upgrades on existing facilities. A total of 45 proposals were submitted for option 1a.

The RTO is working with entities who submitted proposals to identify issues in the planning process, Berner said, while also utilizing consultants as part of the competitive process to begin evaluations of construction processes and financial terms for the proposals.

Berner said PJM is concentrating on starting evaluations for 26 proposals that call for new offshore transmission connection facilities and eight proposals looking at offshore transmission networks. Berner said offshore transmission is more complicated because they're not "traditional" facilities PJM has experience with building.

PJM is working toward adopting the schedule provided in the NJBPU guidance *document* indicating certain processes to be employed going forward during the project evaluations. New Jersey retains the right to elect to move ahead with any of the projects and is targeting the end of 2022 to make final decisions.

Berner said many of the proposals will be adjustable for changes in "scheduling accommodations" and the megawatt injection quantities based on NJBPU needs.

The BPU has already awarded three offshore wind projects in two solicitations: the 1,100-MW Ocean Wind 1 and 1,148-MW Ocean Wind 2 projects, both developed by Ørsted, and the 1,510-MW Atlantic Shores project, a joint venture between EDF Renewables North America and Shell New Energies US. The BPU is planning to hold three more solicitations over the next five years to help the state reach its goal of supplying 7,500 MW of offshore wind by 2035. (See *NJ Awards Two Offshore Wind Projects*.)

Generation Deactivation Notification

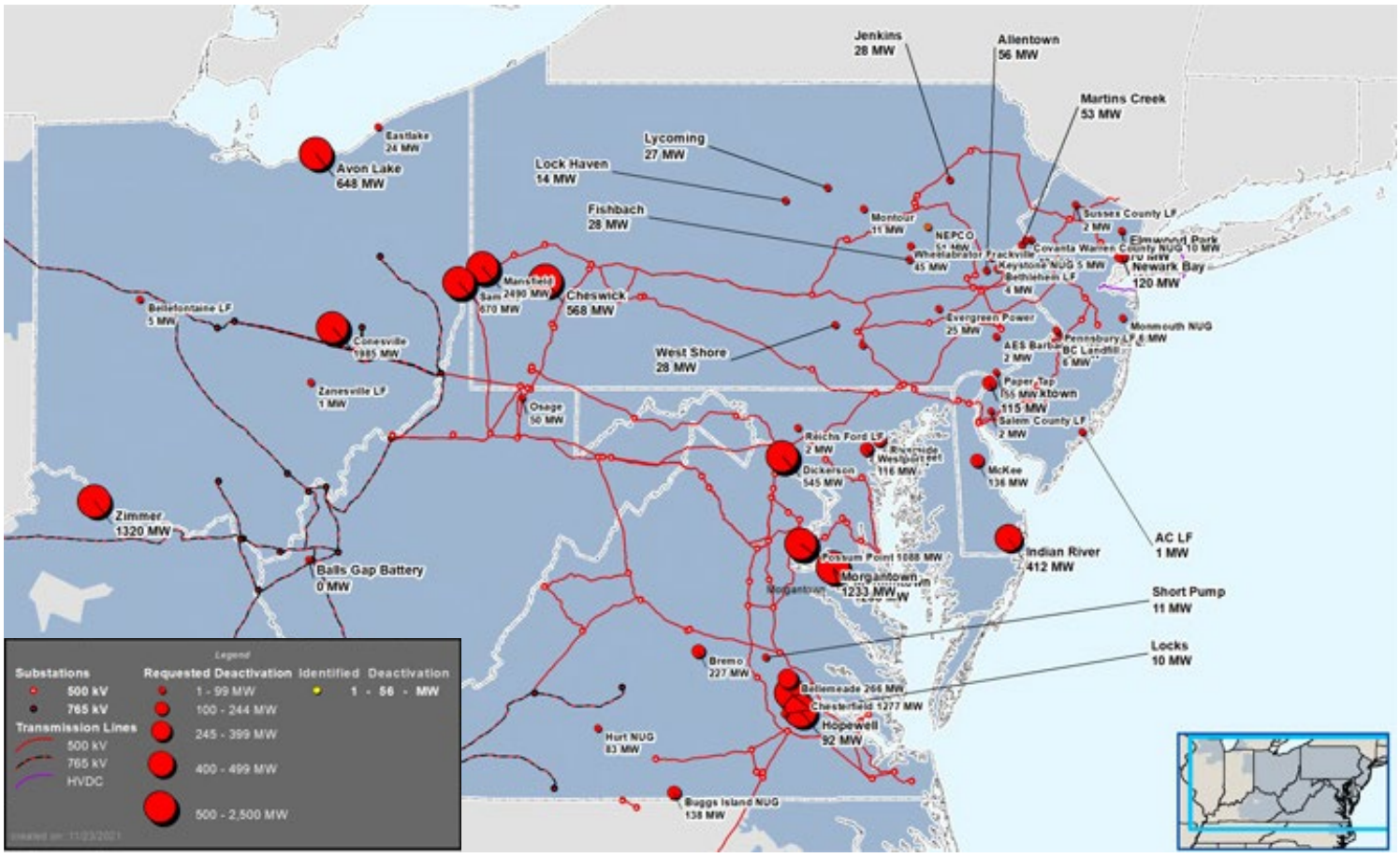
Phil Yum of PJM *provided* an update on recent generation deactivation notifications.

Yum said PJM received two battery deactivation requests in the ComEd transmission zone, including the Joliet Energy Storage battery and the West Chicago Energy Storage battery, which are both six years old.

Each battery unit has 20-MW capabilities for the energy portion, Yum said, but they were listed as 0 MW for capacity.

The requested deactivation date for both units is Feb. 8, and a reliability analysis is underway. ■

— Michael Yoder



Generation deactivation announcements in PJM from 2018-present | *PJM*

PJM News

PJM MIC Briefs

Fuel-cost Policy Standards Proposal Endorsed

Stakeholders endorsed a joint PJM/Independent Market Monitor proposal regarding fuel-cost policy standards at last week's Market Implementation Committee meeting.

The proposal, which was developed at the Cost Development Subcommittee, received 221 votes in favor (95%) and won 192 votes (95%) favoring it over the status quo.

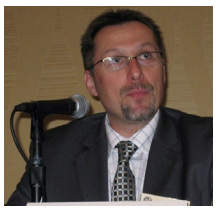
Melissa Pilong, senior analyst in PJM's performance compliance department, *reviewed* the *proposal* clarifying fuel-cost policy standards in *Manual 15* and *Operating Agreement Schedule 2* penalty language. The proposal was first presented at last month's MIC meeting. (See "Fuel-cost Policy Standards and Penalties," *PJM MIC Briefs: Nov. 3, 2021*.)

Pilong said the proposal includes a combination of clarifications and language for more elaboration on PJM's fuel-cost policies resulting from the RTO's examination of the fallout from the February winter storm in Texas and other parts of the South and Midwest.

It would have market sellers of generation units verifying that all intraday offer triggers are specified in the unit's fuel-cost policy. Market sellers will also have to verify that weekend or holiday natural gas estimation practices match either the default assumptions in the PJM *Fuel Cost Policy Guidelines* contained in Manual 15 or specify estimation practices in the unit's policy.

"This takes the burden off the market seller to have to update their fuel-cost policy to clarify what their estimation practice is," Pilong said.

The Manual 15 updates include changes to the intraday update triggers. Pilong said market sellers need to have a one-time trigger to update the maximum allowable cost offer to opt into intraday offers.



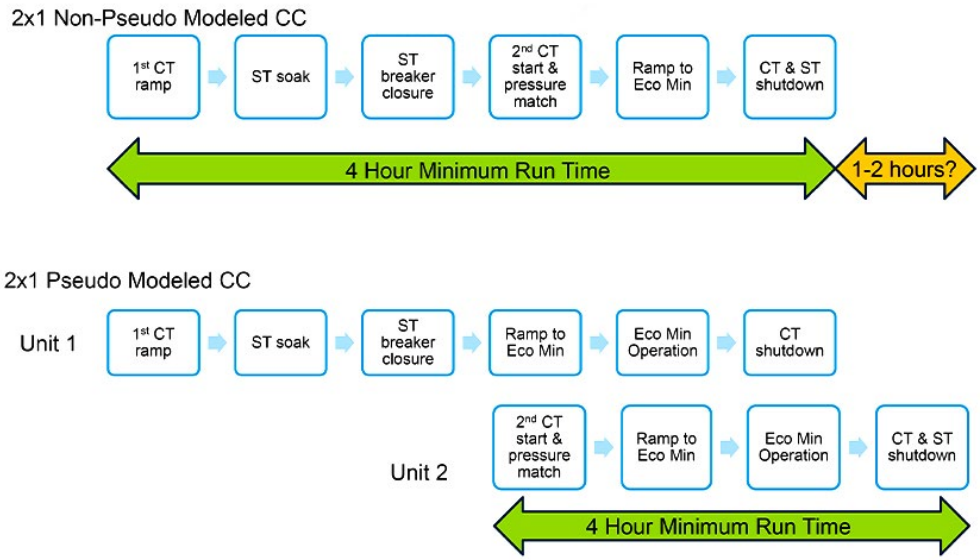
Paul Sotkiewicz, E-Cubed Policy Associates | © *RTO Insider LLC*

Paul Sotkiewicz of E-Cubed Policy Associates said he wished the issue would have been discussed in a different venue, calling attendance of the Cost Development Subcommittee "spotty at best." Sotkiewicz said most stakeholders don't have the ability to attend all PJM meetings, and many of the issues discussed at the CDS are "extremely down in the weeds and esoteric."

Sotkiewicz requested that PJM find a way to bring some of the issues discussed at groups like the CDS to the MIC for broader discussions before they're voted on.

"These are potentially pretty substantial changes that are happening that affect all generation owners," Sotkiewicz said.

PJM will seek final endorsement of the proposal at the Members Committee in February and issue a FERC filing following approval by the Board of Managers.



Comparison of a 2x1 combined cycle unit with a pseudo-modeled 2x1 combined cycle unit when dispatched on a parameter-limited schedule | *PJM*

Virtual Combined Cycles Regulation Endorsed

A proposal from Vistra addressing regulation for virtual combined cycles received unanimous stakeholder support in an acclamation vote.

Michael Olaleye, senior engineer with PJM's real-time market operations, *reviewed* the *proposal* to revise *Manual 12*. The issue charge was originally endorsed at the May MIC meeting and worked on during committee meetings. (See "Virtual Combined Cycle Regulation Issue Charge Endorsed," *PJM MIC Briefs: May 13, 2021*.)

Olaleye said units that are modeled virtually by PJM can sometimes receive varying regulation awards from the market clearing engine, which Vistra has been experiencing with some of its units. When a combined cycle unit is modeled as multiple virtual units, there is a possibility for unbalanced or unequal regulation awards to each unit by the engine.

Vistra's proposed enhancement to performance group scoring calls for calculating the "hourly" score and extending it to each market resource with an assigned regulation for the given hour. It also called for PJM to calculate the "historic" performance score and extend it to each market resource in the performance group.

Olaleye said the enhancements would ensure that all resources of the performance group have the same historic performance score, which should fix the regulation clearing calculation problem in the software.

Becky Robinson, Vistra | *Vistra*

Becky Robinson of Vistra said the proposal should solve the identified problem that only impacts a "handful" of market participants while having "no negative effects" for other market participants not impacted by the regulation for virtual combined cycle units.

PJM News

Capacity Offer Opportunities

Jason Barker of Exelon provided a first read of a *problem statement* and *issue charge* in conjunction with Brookfield Renewable to address the treatment of generation with co-located load and to examine capacity offer opportunities.

Barker said there's a "burgeoning consumer interest" in co-locating new, large interruptible commercial loads behind the wholesale meter of existing generation resources. He said interested customers include those engaging in commercial activities like Bitcoin mining, server farms and hydrogen electrolysis that require "very fast" curtailment times of 10 minutes or less in their facilities.

Jason Barker, Exelon | *© RTO Insider LLC*

"This is a discreet and novel issue due to the characteristics of the load," Barker said.

Customers are expressing preferences for a low-cost physical energy supply, Barker said, while others are seeking a carbon-free physical energy supply.

Barker said PJM's current market rules make customer choices "challenging," resulting in "unduly costly and inefficient outcomes for the grid." He said PJM markets don't offer options for fast-response interruptible customers to select physical supply from their choice of generator technology.

The issue charge includes investigating clarifications and market rule changes to support new interconnection configurations for highly interruptible load that is co-located with generation. Key work activities cited include education regarding current capacity offer requirements for existing generation resources and interconnection requirements for "new, large, fast-response interruptible commercial load."

The expected deliverables in the issue charge are potential modifications to capacity market rules in the PJM tariff and relevant manuals and potential modifications to cost-based offer rules.

Work on the issue is expected to take six months at the MIC.

Consultant Roy Shanker said he believes state rules on the retail side will be relevant to the discussion, suggesting that the key work activities include education on how the modifications will interact on the retail side.

"There are lots of interesting rules and laws that may or may not apply to these kinds of arrangements based on state franchise laws," Shanker said.

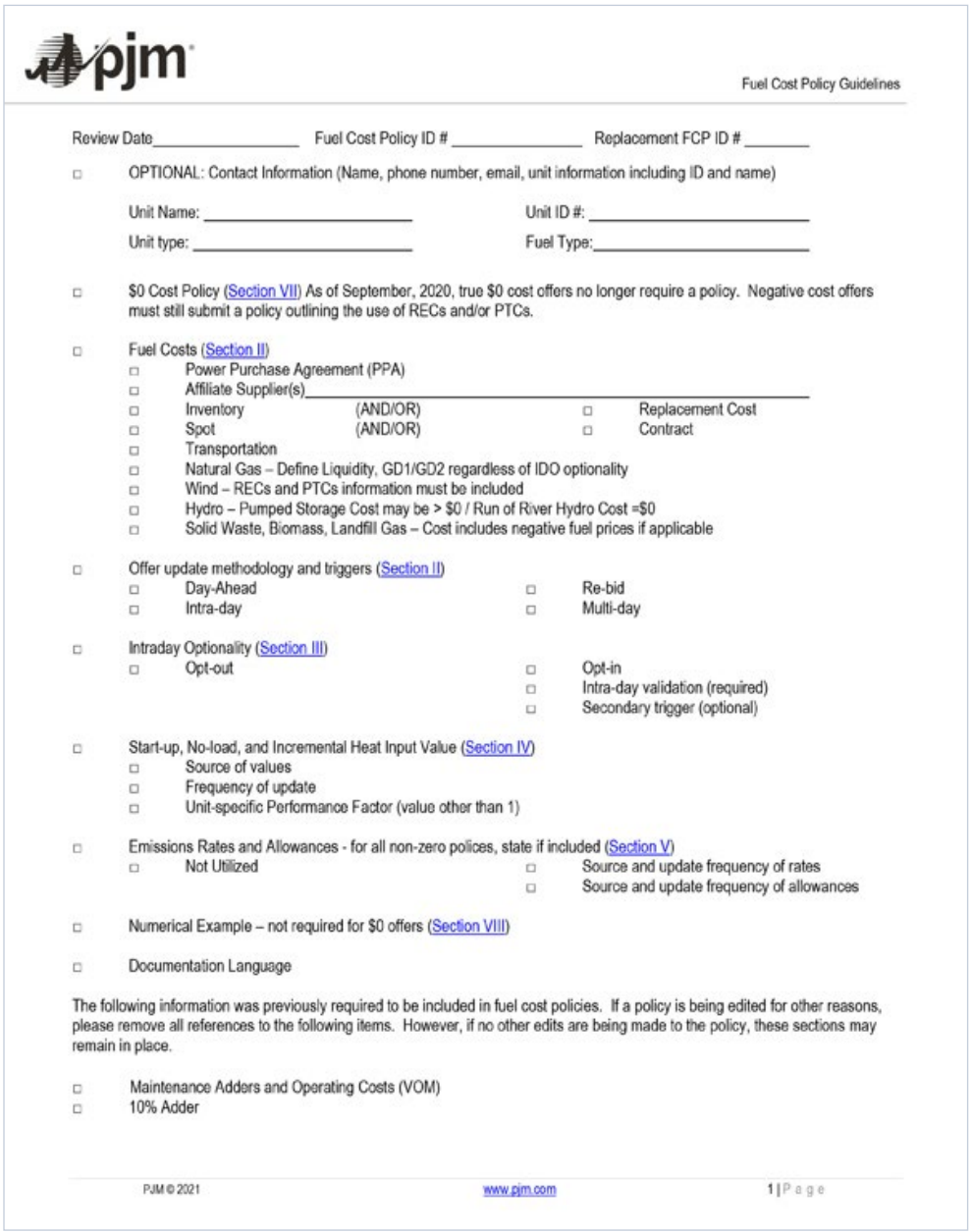
Erik Heinle of the D.C. Office of the People's Counsel said he would like to see education included about how other RTOs and ISOs are handing the issue of generation with co-located load.

PJM Monitor Joe Bowring | *© RTO Insider LLC*

Monitor Joe Bowring said the key work activities listed in the issue charge "make sense," but he was a "bit skeptical" about how the issue is laid out for discussion. Bowring said the language can be interpreted as providing capacity value to the behind-the-meter customer but requiring other customers to pay for it.

Bowring suggested the issue charge should be revised to be more neutral but that it remains an important topic to discuss.

"It's fundamentally about how the costs are getting assigned and who's winning and who's losing as a result," Bowring said. "This is a po-



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Fuel Cost Policy Guidelines

Review Date_____ Fuel Cost Policy ID # _____ Replacement FCP ID # _____

- ☐ OPTIONAL: Contact Information (Name, phone number, email, unit information including ID and name)
  - Unit Name: _____ Unit ID #: _____
  - Unit type: _____ Fuel Type:_____
- ☐ $0 Cost Policy (Section VII) As of September, 2020, true $0 cost offers no longer require a policy. Negative cost offers must still submit a policy outlining the use of RECs and/or PTCs.
- ☐ Fuel Costs (Section II)
  - ☐ Power Purchase Agreement (PPA)
  - ☐ Affiliate Supplier(s)_____
  - ☐ Inventory (AND/OR) ☐ Replacement Cost
  - ☐ Spot (AND/OR) ☐ Contract
  - ☐ Transportation
  - ☐ Natural Gas – Define Liquidity, GD1/GD2 regardless of IDO optionality
  - ☐ Wind – RECs and PTCs information must be included
  - ☐ Hydro – Pumped Storage Cost may be > $0 / Run of River Hydro Cost =$0
  - ☐ Solid Waste, Biomass, Landfill Gas – Cost includes negative fuel prices if applicable
- ☐ Offer update methodology and triggers (Section II)
  - ☐ Day-Ahead ☐ Re-bid
  - ☐ Intra-day ☐ Multi-day
- ☐ Intraday Optionality (Section III)
  - ☐ Opt-out ☐ Opt-in
  - ☐ Intra-day validation (required)
  - ☐ Secondary trigger (optional)
- ☐ Start-up, No-load, and Incremental Heat Input Value (Section IV)
  - ☐ Source of values
  - ☐ Frequency of update
  - ☐ Unit-specific Performance Factor (value other than 1)
- ☐ Emissions Rates and Allowances - for all non-zero polices, state if included (Section V)
  - ☐ Not Utilized ☐ Source and update frequency of rates
  - ☐ Source and update frequency of allowances
- ☐ Numerical Example – not required for $0 offers (Section VIII)
- ☐ Documentation Language

The following information was previously required to be included in fuel cost policies. If a policy is being edited for other reasons, please remove all references to the following items. However, if no other edits are being made to the policy, these sections may remain in place.

- ☐ Maintenance Adders and Operating Costs (VOM)
- ☐ 10% Adder

PJM © 2021 www.pjm.com 1 | Page

PJM's fuel cost policy form | *PJM*

PJM News

tentially radical change to the capacity market design."

The committee will be asked to approve the issue charge at the January MIC meeting.

Minimum Run Time Guidance

Tom Hauske, principal engineer in PJM's performance compliance department, *provided* education and a first read of a *problem statement* and *issue charge* addressing pseudo-modeled combined cycle minimum run time guidance.

Hauske said PJM and the Monitor were bringing the issue forward as a result of the "disaggregation of many multiple block combined cycles" into individual pseudo-model market units, or virtual modeled combined cycle units. Market sellers can currently model a combined cycle unit as multiple pseudo units composed of a single combustion turbine and a portion of a steam turbine.

Hauske said if the market units of a pseudo-modeled unit are dispatched at different times on parameter-limited schedules, the potential exists for one or more of the pseudo-modeled units to operate "for some period beyond the minimum run time parameter limit for an identical non-pseudo-modeled combined cycle unit."

The issue charge includes a key work activity of stakeholders developing guidance for market sellers regarding offering operating parameters for pseudo-modeled combined cycle units through education on the issue. Expected deliverables include revisions to Manual 11 or other relevant PJM governing documents.

Hauske said PJM was looking to use the "CBIR Lite" (Consensus Based Issue Resolution) process in *Manual 34* to develop any manual changes and have final endorsements of any changes by the Markets and Reliability Committee's meeting March 23.

Calpine's David "Scarp" Scarpignato said the issue was a "little bit complex" to use the CBIR Lite process and that it would be better to conduct discussions under the normal CBIR process. Scarp said he prefers to use the normal CBIR process in stakeholder discussions "unless there's a real reason to deviate from them."

"I don't see a burning reason to go to the Lite process here," Scarp said.

Hauske said the shorter process was suggested because PJM's unit-specific parameter adjustment process starts on Feb. 28 with market sellers submitting requests. PJM must provide a determination on the requests by April 15.

Scarp said he "doesn't see a huge reliability" threat if the issue isn't resolved in time and didn't want to rush discussions to get imperfect language implemented. He said the prior rules were used last year, and there were no major reliability concerns.

"I definitely want to get the work done, but I want to get it done in due diligence and a conscientious fashion," Scarp said.

De-energized Bus Replacement

Vijay Shah, lead engineer in PJM's real-time market operations department, *provided* a first read of conforming revisions to *Manual 11: Energy and Ancillary Services Market Operations* as part of five-minute dispatch and pricing. The changes are designed to address enhancements to the dead bus replacement logic for assigning prices to de-energized pricing nodes (pnodes).

Shah said the objective of the revisions are to provide increased transparency in the logic and how it performs replacements for de-energized buses. PJM is required to produce LMPs for all pnodes in the RTO's network model for all intervals, including de-energized pnodes.

Shah said PJM wants to use new logic based on Dijkstra's algorithm, an industry standard, to find a suitable replacement for de-energized pnodes. He said the algorithm uses the "least impedance path" to find a suitable source, and it's to be implemented in both day-ahead and real-time market clearing engines.

The manual changes include updated language to reflect the new logic.

The committee will be asked to endorse the manual revisions at the MIC's meeting Jan. 12, with final endorsement at the Jan. 26 MRC meeting. The new dead bus replacement logic would be effective March 1.

Manual 6 Revisions Endorsed

Members unanimously endorsed conforming changes to *Manual 6* resulting from the endorsement of a proposal to address PJM's auction revenue rights and financial transmission rights at the October MRC meeting. (See *Stakeholders Endorse PJM ARR/FTR Market Changes*.) Emmy Messina, senior engineer with the PJM market simulation department, first *presented* the manual changes at the November MIC meeting. (See "Manual 6 Revisions," *PJM MIC Briefs: Nov. 3, 2021*.)

Messina said the changes would only impact Manual 6 and include language for bid limits and the network model user guide. The changes would update section 6.6 to reflect an increase of bid limits from 10,000 to 15,000 per corporate entity, auction round and period in FTR auctions. The February 2022 auction will be the first FTR auction with the updated limits.

Section 9.1 was also updated to direct stakeholders to a new network model user guide on the FTR section of the PJM website to get additional information on the auction.

PJM will now seek endorsement of the manual changes at the December MRC meeting. ■

— Michael Yoder

PJM News

PJM Operating Committee Briefs

DLR First Read

PJM is looking to create guidance and requirement language for several manuals related to the implementation of a dynamic line rating (DLR) system in the RTO.

Chris Callaghan, senior business solution engineer with PJM's applied innovation department, *presented* a first read of a *problem statement* and *issue charge* at last week's Operating Committee meeting.

Transmission lines are typically operated using a static rating calculated for periods of time using near worst-case values for predicted weather conditions, but DLRs can be calculated in real time and show the resulting weather and other environmental impacts to the line ratings.

Callaghan said DLR deployments in PJM will involve the installation of a data collection sensor on or near an existing transmission line to collect real-time conductor temperature information. The sensor technologies that will be deployed in PJM include weather stations, electromagnetic field detectors and thermal cameras.

While different sensor technologies exist, Callaghan said, PJM wants to see the DLR installation projects have a common goal of targeting congested transmission facilities where the conductor is the most limiting element.

PJM has identified several manuals that may require new language for the incorporation of DLRs. The updates include section 2 of *Manual 1* related to member control center requirements, section 2 of *Manual 3* on thermal operating guidelines and appendix A of *Manual 3A* on the transmission equipment rating monitor equipment ratings update process.

Sharon Midgley, Exelon | © *RTO Insider LLC*

The proposed problem statement calls for the incorporation of supporting manual language to ensure the "efficient and reliable operation" and use of equipment DLR systems in various aspects of operations, markets and planning. Callaghan said the opportunities driving the effort include reliability and economic benefits associated with DLR technology.

"The interest here is transparency to members and the reliability mission of PJM," Callaghan said.

Expected deliverables in the issue charge include stakeholder education of DLRs and potential new or modified governing language in the manuals.

Callaghan said PJM was looking to use the "CBIR Lite" (Consensus Based Issue Resolution) process to come up with a single proposal. The discussions would occur at normal OC meetings and are expected to take more than two months.

Adrien Ford of Old Dominion Electric Cooperative said she disagreed with using the CBIR Lite process and had anticipated more expected deliverables and key work activities in the issue charge. Ford said PJM should be "very careful" to keep the issue narrow if the RTO wants the DLR work done quickly in the OC.

Calpine's David "Scarp" Scarpignato said he was hoping for a deliverable focused on the placement of DLRs on the grid. Scarp said DLRs are "very important to modernize the transmission grid," but it will be necessary to make sure their placement is not discriminatory.

Scarp also said he doesn't know what criteria and guidelines transmission owners plan to use for the installation of DLRs. "I think an important expected deliverable has to be criteria for where to implement DLR."

Eric Hsia of PJM said the RTO recognizes the importance of DLR placement. Hsia said PJM wanted to focus on adding support language on the physical operations of DLR in the proposed problem statement and issue charge and that the DLR placement issue could better be handled at the Planning Committee in a separate problem statement and issue charge.

Sharon Midgley of Exelon said PJM should be "very careful" in doing a legal review to "respect" the delineation of responsibilities between the TOs and the RTO when it comes to decisions on the placement of DLRs on the transmission system.

Adrien Ford, ODEC | © *RTO Insider LLC*

"I get a little nervous when I hear things like new requirements and new criteria," Midgley said.

The OC will be asked to approve the issue charge at the Jan. 13 meeting.

Renewable Dispatch First Read

Darrell Frogg of PJM's generation department, presented a first read of a *problem statement* and *issue charge* to improve dispatching renewable resources and increase forward-looking visibility.

Frogg said PJM is already discussing renaming the issue to "intermittent resource dispatch" instead of "renewable dispatch" to better align with existing language in the RTO's governing documents. Frogg said PJM wanted to keep the issue broad to include all renewable resources.

The growing number of renewable resources on the grid has led to some "new operational issues and impacted existing issues," Frogg said, including a greater dependence on the ability to accurately dispatch renewable resources in real time and forecast near-term changes. Frogg said as the number of renewable resources grows, manually managing dispatch becomes more difficult and leads to inconsistent performance when following curtailments and/or basepoints.

Frogg said PJM sees an opportunity to improve several main aspects of renewable dispatch, including developing a method that covers all

PJM News

renewable resources and a streamlined data exchange.

The key work activities of the issue charge include reviewing education on the existing renewable dispatch practices and the expectations from PJM and its members. The goal is to propose solutions to enhance the overall renewable dispatch process.

Areas in scope for discussion in the issue charge are the methods in which PJM dispatches renewable resources, communication of dispatch mode and instructions, and lost opportunity cost eligibility. Out-of-scope items include existing market products and calculations and ongoing revisions such as those related to FERC Order 2222 and the treatment of solar-battery hybrids. (See "Solar-battery Hybrid Resources," *PJM MRC/MC Briefs: Nov. 17, 2021*.)

The expected deliverables in the issue charge are changes to resource expectations when dispatched in real time and manual language and potential governing document changes to reflect the proposal.

Work on the issue charge would take place in the OC or its special sessions, reporting out to Market Implementation Committee when needed. The work is estimated to take six months, and PJM was looking to pursue the CBIR Lite approach to develop a proposal.

Scarp said he didn't think the issue should be part of the CBIR Lite approach. He said PJM staff are "extremely well versed" on the issue and think it can be solved quickly, but the stakeholder process can take longer as members need to be brought up to speed on complicated issues.

"We may end up at the same positions as PJM, but we have to have time to get there in order to vote for it," Scarp said.

Sean Chang of Shell Energy said he would like to see some education on comparing what other RTOs and ISOs are doing on the renewable dispatch issue.

"Some of the other areas with more renewable penetration have had some challenges operationally, and it could be helpful to compare and contrast," Chang said.

The OC will be asked to approve the issue charge at its next meeting.

Manual 38 Changes

Liem Hoang of PJM *reviewed* proposed changes to *Manual 38: Operations Planning* as a part of a periodic review during a first read.

Hoang said the minor changes include updating the Eastern Interconnection Reliability Assessment Group study and PJM participation in the group. Language was added to state that the group will conduct "assessments to identify key reliability issues and the risks and uncertainties affecting adequacy and security of the bulk power system in the Eastern Interconnection."

The OC will be asked to endorse the changes at its Jan. 13 meeting, with final adoption at the Markets and Reliability Committee meeting Jan. 26. ■

— Michael Yoder

David "Scarp" Scarpignato, Calpine | *© RTO Insider LLC*

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SPP News

FERC Splits on Waivers from SPP IC Process

By Tom Kleckner

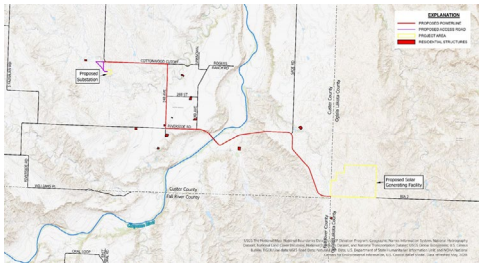
FERC last week settled a pair of disputes over waivers from SPP's generator interconnection procedures (GIP), approving one and denying the other.

The commission reaffirmed Lookout Solar Park's request for a limited waiver of the GIP's financial security cure period and posting requirements in responding to SPP's rehearing request (*ER21-1841*). However, the agency also denied Invenergy's request for a prospective waiver from GIP security posting requirements (*ER21-2807*).

In the first Dec. 1 order, FERC found that the waiver request it granted Lookout Solar earlier this year satisfied the commission's criteria for granting waivers in that the request did not harm third parties or have undesirable consequences. It clarified that the waiver order extended Lookout Solar's timeline to either make the applicable financial security payments or withdraw from the generator interconnection queue.

Lookout Solar is developing a 110-MW solar facility in South Dakota and entered the SPP GI queue in 2017. It said in its waiver request that the grid operator posted the results of its definitive interconnection system impact study (DISIS) queue cluster on Oct. 30, 2020, but then reposted revised results on Nov. 20, 2020, triggering a requirement that Lookout Solar post about $16.9 million in financial security.

The developer disputed the revised obligation and said it had reached an agreement via email with SPP that further modified the obligation to $8.1 million. The RTO posted additional study results in April allocating Lookout Solar $181.6 million in upgrades and requiring $28.1 million in financial security. SPP subsequently notified the cluster's customers that it had identified errors in the DISIS and extended the cluster's next decision point until May 13.



The proposed Lookout Solar Park in South Dakota | *WAPA*

Construction at an Invenergy wind facility | *Invenergy*

The solar developer contended that SPP acknowledged that the study "appeared" to over-allocate certain upgrade costs to the facility. It said the RTO did not revise the reposted study results and ultimately told Lookout Solar that no substantive corrections were required.

SPP withdrew Lookout Solar from the queue and asked that it post its financial security amounts to restore its position, leading the developer to file its waiver request. FERC granted the request over SPP's objections.

Commissioner James Danly concurred separately with the order but expressed his "continuing concern" over the "innumerable" waiver requests FERC grants and reiterated that the commission "must be sparing in its liberality."

Invenergy Issue not 'Concrete'

The commission found that Invenergy did not demonstrate that its potential loss of posted financial security "is a concrete problem that warrants waiver" in the second order.

The renewable developer said it had eight interconnection requests pending in the same DISIS queue cluster as Lookout Solar. It alleged that SPP said the DISIS study would need to be redone because higher-queued requests were withdrawn from an earlier cluster. Invenergy said a discussion with SPP staff about the upgrades and assigned cost allocations left its questions unresolved.

Invenergy said that faced with the choice of withdrawing its requests or posting a third financial security to preserve its option to stay in the queue and avoid losing previously paid security amounts, it chose to post security under protest for three of its eight projects.

FERC said Invenergy did not show that its potential loss of its posted financial security was a concrete problem warranting a waiver from SPP's tariff. It said there was not sufficient detail to demonstrate that an IC customer having to make decisions and provide financial security based on information it views as unsatisfactory warrants granting the waiver.

The commission also said Invenergy's waiver request is distinguishable from Lookout Solar's request in that the agency relied on undisputed allegations in the record of SPP's inconsistent communications and actions.

Commissioner Mark Christie dissented from both orders, saying that after reading the Lookout Solar rehearing order, he could "reach no conclusion other than that today's [second] order unduly discriminates against Invenergy in an unlawful manner."

He said there is no "rational basis" for distinguishing between Invenergy and Lookout Solar and said the decision to deny Invenergy's waiver on "thin factual differences is mystifying."

"Today the commission relies on semantics to get itself out of the mess it inevitably made by granting the initial waiver in Lookout Solar — the result of which is to put Invenergy (and presumably any subsequent waiver applicants in the cluster) at a patently discriminatory commercial disadvantage to another member of the queue without any rational basis to distinguish the two waiver requests," Christie wrote. ■

Company Briefs

Eversource Announces New President of Conn. Operations

Eversource Energy last week announced that Steve Sullivan takes over as new president of the Connecticut Light & Power, effective Sunday.

Sullivan, who is a Connecticut resident and has been a company employee for more than 30 years, will oversee electric operations and system maintenance and will lead the company's storm response and resource allocation decisions with the Connecticut Incident Command Team.

More: *Eversource Energy*

LG Energy Solution Secures $1.36B for EV Battery Production

LG Energy Solution last week said it secured $1.36 billion in investments to build production facilities for electric-vehicle batteries in North America by 2024.

The funding is a part of a plan from the batteries unit of South Korea-based LG Corp. to expand its solely owned annual production capacity in North America from its current 5 GWh in Holland, Mich. It is not clear if Michigan will see any of the investment, which was disclosed in a regulatory filing in Korea.

More: *The Detroit News*

Tesla Files Legal Papers to Officially Move HQ to Austin

Tesla last week released a report filed with the Securities and Exchange Commission that stated the company now will be run from a location in Austin, Texas, near the Austin-Bergstrom International Airport.

CEO Elon Musk first stated during a shareholder meeting in October that he was planning to move the company's headquarters from Palo Alto, Calif., to Austin. Musk admitted that part of the reason for the move was his anger at the state of California after it attempted to stop his Fremont plant from operating in 2020 in the wake of COVID-19.

More: *Newsweek*

Federal Briefs

FERC Swears in Phillips as Commissioner

FERC last week swore in Willie Phillips as a commissioner.

Phillips, who will serve a five-year term ending on June 30, 2026, was nominated by President Joe Biden in September. The Senate confirmed his nomination on Nov. 16.

Phillips most recently served as chairman of the Public Service Commission of the District of Columbia. Prior to the DCPSC, Phillips served as assistant general counsel for NERC.

More: *FERC*

Commissioner Willie Phillips being sworn in | *FERC*

FERC Extends Temporary Operations for Spire STL Pipeline

FERC last week issued a temporary certificate to Spire STL Pipeline to continue operating its pipeline serving the greater St. Louis area through the winter season.

Last June, the U.S. Court of Appeals for the D.C. Circuit vacated, and remanded back to the commission, the 2018 certificate FERC had issued to Spire, saying the commission improperly relied on a single precedent agreement between Spire and its affiliated shipper to establish need and failed to adequately weigh the project benefits against the adverse effects. In light of the decision, Spire submitted an application for a temporary certificate seeking to continue operations to serve customers through the 2021-22 winter heating season.

In September, FERC issued a 90-day certificate to ensure the pipeline could continue operating as it considered the application.

More: *FERC*

IEA: Renewables to Lead Power Growth over Next 5 Years

The International Energy Agency last week said renewables will account for about 95% of growth in global power-generation capacity by the end of 2026.

About 290 GW of new renewable energy generation capacity, mostly in the form of wind turbines and solar panels, has been installed around the world this year. Based on current trends, renewables capacity will exceed that of fossil fuels and nuclear energy combined by 2026, the agency predicts. However, the level of growth is only about half of what would be required to meet net-zero carbon emissions by 2050.

More: *The Guardian*

State Briefs

CALIFORNIA

San Diego to Stop Investing in Fossil Fuel Industry

San Diego last week said it will no longer invest financial reserves in the fossil fuel industry because it contradicts municipal efforts to fight climate change. It will sell off a recent $17 million investment in Chevron before the new policy takes effect Jan. 1.

A fossil fuel divestment policy was first proposed almost two years ago by Councilmember Chris Ward, who left council last December to join the Assembly. Councilmember Joe LaCava said that the council gets a chance to review and adjust its investment policies each year, so the new prohibition can be modified if there are unintended consequences.

City officials didn't say whether any other holdings in San Diego's $2.33 billion portfolio must be sold.

More: *The San Diego Union-Tribune*

COLORADO

Comanche 3 to Close Early

Pueblo County Commissioners last week unanimously approved an agreement with the Public Service Company of Colorado, the parent company for Xcel Energy, to close the Comanche 3 coal-fired power plant by Dec. 31, 2034.

The utility also agreed to pay Pueblo County a "community assistance payment" equal to current property taxes to the tune of $25 million annually from 2035 to 2040.

With the closure, the emissions reduction will exceed the state requirement of 75% but fall short of the company's target of 90%.

More: *The Pueblo Chieftain*

Delta-Montrose Electric Loses 25 Years of Data after Cyberattack

Delta-Montrose Electric Association (DMEA) was still struggling to recover last week from a devastating cyberattack in October that took down 90% of its internal systems and caused 25 years of historical data to be lost.

The company said it began noticing issues on Nov. 7, and the attack eventually brought down most of its internal network services. The attack affected all the company's support systems, payment processing tools, billing platforms and other tools provided to customers. DMEA said the hackers were targeting specific parts of its internal network and corrupted saved documents, spreadsheets and forms, indicating it may have been a ransomware incident. It even affected the company's phone and email systems, but DMEA said the power grid and fiber network were not touched during the attack.

The company has hired cybersecurity experts who are investigating the incident.

More: *ZDNet*

District of Columbia

Thompson Appointed Interim Chairman of PSC

Mayor Muriel Bowser last week appointed

Emile C. Thompson as interim chairman of the Public Service Commission.

Prior to the commission, Thompson was an assistant United States attorney in the U.S. Attorney's Office for the District of Columbia where he prosecuted homicides and served as a supervising deputy chief in the Misdemeanor Section.

Thompson was appointed to the role after Willie Phillips resigned to join FERC.

More: *The Public Service Commission of the District of Columbia*

KENTUCKY

LG&E Agrees to $750K Civil Penalty in Air Pollution Case

Louisville Gas & Electric Co. last week agreed to pay a $750,000 civil penalty and permanently limit emissions from its Mill Creek Station coal-fired power plant, the Justice Department said. The proposal, which was filed in U.S. District Court, still needs court approval.

A complaint filed in July 2020 alleged that LG&E's "coal combustion operations emitted high levels of sulfuric acid mist, affecting the surrounding community and violating certain federally enforceable general provisions of Kentucky's Clean Air Act State Implementation Plan," the Justice Department said.

LG&E continues to deny the allegations.

More: *The Associated Press*

LOUISIANA

Venture Global to Invest $10B to Develop LNG Facility

Gov. John Bel Edwards and Venture Global LNG CEO Mike Sabel last week announced the company will invest more than $10 billion in a new liquefied natural gas facility that will use carbon capture and sequestration technology to reduce carbon dioxide emissions.

The facility, named CP2, will have a capacity of 20 million metric tons per annum of LNG. The carbon capture process will capture and store underground an estimated 500,000 tons of emissions from the facility annually.

More: *Office of the Governor*

NEVADA

Solar Project Racks Up Fines for Blowing Dust

The Townsite Solar Garden project has been fined nearly $220,000 since April for failing to control dust during construction, said Clark County officials.

County Environment and Sustainability Director Marci Henson said dust particles can be unhealthy, particularly for people with existing respiratory conditions. She estimated up to 70 tons of excess dust has blown from the site.

Amy Sue Ambrose, Rosendin Electric environmental director, said the company spent $3 million and has six full-time employees assigned to manage dust on the challenging wedge-shaped site.

More: *The Associated Press*

NORTH CAROLINA

Assembly Passes Bill that Eliminates Fuel Type Discrimination

The General Assembly last week finalized a bill that would prohibit local governments

from barring a type of energy service based on the fuel type, such as natural gas.

The bill, passed by the Republican-controlled legislature, is expected to receive scrutiny from Democratic Gov. Roy Cooper.

More: *The Associated Press*

OKLAHOMA

Oklahoma Natural Gas Customers Should Expect Monthly Bill Increase

The Corporation Commission last week approved a $15.25 million settlement agreement with Oklahoma Natural Gas that will result in an average monthly rate increase of $1.27.

However, the settlement includes an order that will require ONG to apply a $10.6 million tax credit received under the Tax Cuts and Jobs Act of 2017 to the rates. That credit will be applied in February 2022 and lower the overall increase to 34 cents a month on average.

ONG originally applied for a $28.69 million increase.

More: *KJRH*

OREGON

Jordan Cove LNG Project Abandoned

Pembina Pipeline Corp. last week pulled the plug on its Jordan Cove liquefied natural gas project after failing to obtain all the necessary state permits.

Although FERC approved the project in March 2020, the state Department of Environmental Quality denied a water quality certification, while the Department of State Lands refused to grant another extension for the company to file documents in its application for a permit to dredge sediment out of Coos Bay. Then, on Feb. 8 of this year, the U.S. Department of Commerce sustained Oregon's objection under the Coastal Zone Management Act.

Donald Sullivan, manager and associate general counsel of the project, told FERC in a notification that the company reviewed the prospects for obtaining the permits in the future and "decided not to move forward with the project."

More: *The Associated Press*

TENNESSEE

DEC Approves TVA's Plan to Bury Coal Ash

The Department of Environment and Conservation last week approved the Tennessee Valley Authority's plan to remove tons of coal ash from ponds in Southwest Memphis and transport it to a landfill in Southeast Memphis.

The approval of the plan is the final regulatory barrier to coal ash removal. The work, which will be handled by Republic Services, will take the ash by truck to the South Shelby landfill and bury it in lined pits to prevent leaching into the ground.

The process is expected to take several years.

More: *Memphis Commercial Appeal*

VIRGINIA

Air Board Adopts Clean Car Regulations

The Air Pollution Control Board last week approved regulations that will set up the framework for reducing greenhouse gas emissions from vehicles as part of a California program the General Assembly embraced during its winter 2021 session.

The regulations will require new vehicles to meet increasingly strict limits for nitrogen oxide, carbon monoxide, particulate matter and greenhouse gas emissions. State dealers will be required to sell California-certified vehicles beginning with model year 2025. Manufacturers must also ensure that an increasing proportion of the light- and medium-duty vehicles they sell are electric, fuel cell or plug-in hybrid.

In February, the General Assembly voted to adopt California vehicle emission standards that will not only set more stringent tailpipe limits for light- and medium-duty cars and trucks, but also set targets for electric vehicle sales. Gov. Ralph Northam signed the regulations into law in March.

More: *Virginia Mercury*

Hollow Road Takes Second Crack at Solar Facility

The Frederick County Planning Commission last week voted 10-1 to recommend the approval of a conditional-use permit for an 83-acre, 20-MW solar facility.

Hollow Road Solar, the developer of the project, previously attempted to obtain a permit from the Board of Supervisors in March but was denied. The board claimed it had not seen the impact of two other solar facilities in the county; however, it was then sued by Hollow Road.

The matter will again go before the Board of Supervisors on Dec. 8.

More: *The Winchester Star*