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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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In this week's issue

FERC/Federal News

DOE Announces $3.46B for Grid Resilience, Improvement Projects

MISO-SPP JTIQ Projects to Receive $464 Million

By K Kaufmann

The five transmission lines in MISO and SPP's joint targeted interconnection queue (JTIQ) portfolio are among the *58 grid resilience and improvement projects* designated to receive a total of $3.46 billion in funding from the Infrastructure Investment and Jobs Act.

Announcing the awards during an Oct. 18 press call, Energy Secretary Jennifer Granholm hailed the funding as the "largest-ever investment in the American grid," which would help to deploy 35 GW of new renewable energy projects — providing a 10% increase in renewable capacity — as well as 400 microgrids. Matching funds to the IIJA awards will bring the total investment to $8 billion, she said.

"Right now, the U.S. electric grid is the largest connected machine in the world. It's 5.7 million miles of transmission and distribution, and about 55,000 substations; and it needs upgrading clearly," Granholm said. With the IIJA and the Inflation Reduction Act unleashing a "tidal wave of clean energy investment, the grid as it currently sits is not equipped to handle all the new demand. We need it to be bigger; we need it to be stronger. We need it to be smarter to bring all of these new projects online and to meet the president's goal of 100% clean energy by 2035."

Aimed at improving interregional connections and transfers along the MISO-SPP seams, the JTIQ projects are designated to receive $464 million — the largest single award made — which will put a major dent in the latest revised costs for the portfolio of $1.86 billion. Adjusted for inflation and other rising costs from the original project estimate of $1.1 billion, the revised price tag had raised concerns among stakeholders in the seven states involved: Minnesota, the Dakotas, Iowa, Nebraska, Kansas and Missouri. (See *JTIQ Portfolio Cost Estimate Nearly Doubles to $1.9B*.)

MISO and SPP have been collaborating with the Minnesota Department of Commerce and the Great Plains Institute on the project. MISO has estimated the projects will help to interconnect 28 GW of new, mostly renewable resources.

Maria Robinson, director of DOE's Grid Deployment Office, praised the portfolio as a model. "My hope is that by this particular project showing what excellent planning and amazing cooperation and coordination across

Revised JTIQ portfolio | *SPP*

RTO lines can do that we will see more of those types of projects in future iterations."

In a joint press release, Minnesota Commerce Commissioner Grace Arnold called the award "a historic opportunity to leverage federal clean energy funds to deliver reliable, affordable and safe energy that is increasingly generated by carbon-free and renewable energy resources." The JTIQ will "expand our electric grid with new transmission lines and to reduce the burden of costs to utility ratepayers for adding those needed transmission lines," she said.

Echoing Robinson, David Kelley, SPP vice president of engineering, said, "It's tremendously exciting to think about what these funds will mean for the SPP and MISO regions, and for our industry. As our organizations worked together with our partners and with the DOE, it's been our goal not only to create value for people living in our service territories, but also to model effective collaboration that spans the borders of states, utilities and grid operators."

Real-life Impacts

The Oct. 18 awards are being funded under the *Grid Resilience and Innovation Partnerships* (GRIP) program, which received a total of $10.5 billion in the IIJA.

The program is aimed at enhancing grid reliability and resilience in the face of the increasingly extreme weather caused by climate change, while also funding innovative, "transformative" grid projects.

The $3.5 billion going to the 58 projects represent the first round of the funding, which drew about 700 initial applications, according to a senior administration official. About 300 of those applicants were then invited to submit full proposals.

The funding will also create good-paying jobs, DOE said in a *press release*, with about three-quarters of the projects partnering with the International Brotherhood of Electrical Workers. All projects were also required to have community benefit plans, a senior administration official added in an Oct. 18 press teleconference.

A second round of funding should begin accepting new applications before the end of the year, Granholm said. As with other DOE funding announcements, the projects selected still have to go through contract negotiations with the department before the

FERC/Federal News

awards are finalized.

The amounts range from $1.1 million to the municipal utility in Naperville, Ill., to install a distributed energy resource management system to $250 million for new transmission lines to connect renewable energy resources on tribal lands east of Oregon's Cascade Mountains to Portland General Electric's urban demand centers.

According to DOE, the Oregon project could bring 1,800 MW of clean energy from the Confederated Tribes of Warm Springs Reservation to PGE. The utility will also "deploy an artificial intelligence-enabled, grid-edge computing platform to improve the connection of distributed energy resources, such as solar, as well as informed modeling that can predict pre-outage conditions and assist real-time decisions," the release said.

Clean energy advocates stressed the impact the funding would have on grid resilience and renewable energy deployment.

"As we learned this summer, a larger grid is a resilient grid, and the funding for planning and coordination from today's grants will go a long way toward accelerating these efforts," said John Moore, director of the Sustainable FERC Project at the National Resources Defense Council. The funding is "a critical step in [DOE's] efforts to expand the capacity of the nation's transmission system, increase connectivity between regions and add more clean energy."

"This announcement shows how important building new transmission is to making the transition to a 100% clean energy grid across the country," said Harrison Godfrey, managing director of Advanced Energy United. "The best use of public funds is to leverage [them] to unlock private sector investment and create new, good jobs across America."

The Permitting Question

Besides being the largest, the JTIQ award is also the only one for interregional transmission lines, which are widely seen as critical for grid operators to begin interconnecting the 2,000 GW of renewable and storage projects sitting in their queues at present.

Other projects will provide intrastate HVDC lines, such as the *Railbelt Innovative Resiliency* project in Alaska, which will receive $206.5 million to bolster grid reliability in the state with the addition of an underwater HVDC line and battery energy storage.

Several projects will also deploy grid-enhancing technologies to increase power flows on existing lines. For example, the Electric Power Research Institute is partnering with the Vermont Electric Power Co. on a *project* that will use a technology called advanced power flow control, which can pull power from congested lines and redirect it to lines with excess capacity. The project grant is $18 million.

Electric cooperatives were well represented in the funding, with a range of projects focused on improving grid resilience in rural areas. In New Mexico, the *Kit Carson Electric Cooperative* is vulnerable to power outages from wildfire threats, drought and high winds. The co-op will receive $15.4 million to add battery storage and microgrids in key locations so it can, if needed, shut down its grid for public safety power outages to prevent wildfires while still keeping the power on for critical services in remote communities.

During the press call, a reporter asked about obstacles these projects might face with permitting, as any efforts at permitting legislation have ground to a halt with the House of Representatives still without a speaker.

A senior administration official said that in general, the projects were developed with strong support from their state or local governments and other stakeholders. Many of them will also provide benefits to low-income, disadvantaged communities. A priority for DOE, the official said, was to choose projects that would be able to move forward quickly. ■

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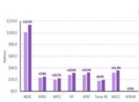

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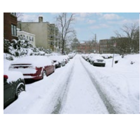

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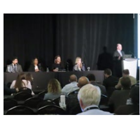

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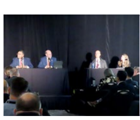

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FERC/Federal News

FERC Orders Reliability Rules for Inverter-Based Resources

NERC Must Submit IBR Rules in Three Yearly Tranches

By James Downing

FERC issued a final rule Thursday directing NERC to develop standards to improve the reliability of inverter-based resources (*RM22-12*).

The final rule covers solar photovoltaics, wind, fuel cell and battery storage, which make up most of the projects in the interconnection queues.

It followed a Notice of Proposed Rulemaking last November. (See *NERC Pushes Alternate IBR Standards Timeline Response to NOPR*.)

"These standards will help us solve one of the biggest problems we're facing as we make the transition to clean energy resources," FERC Chairman Willie Phillips said at the monthly open meeting. "We need to make sure that these promising new technologies can enhance, not weaken, reliability of the grid. We mean it when we say that at FERC, reliability is, and remains, Job No. 1."

NERC was directed to develop rules addressing IBR data sharing, model validation, planning and operational studies, and performance standards. The reliability organization has to submit the rules in three tranches, with each one due no later than Nov. 4 over each of the next three years.

The order gives NERC 90 days to make a filing that includes a detailed, comprehensive standards development and implementation plan.

FERC voting on the orders issued at its regular meeting, including the IBR standard. | *FERC*

IBRs use electronic devices that change the direct current power produced by generators into alternating current power that is then transmitted on the bulk electric system. The concern is that IBRs can respond to grid disturbances differently from traditional resources; at least 12 events have occurred on the bulk power system in which 1,000 MW of IBRs tripped offline, showing the risks they can pose absent reforms, Phillips said.

"We have a lot of clean energy and renewable energy resources that are being connected to the grid. And this new rule is a great step to address what we see as reliability concerns regarding this transition" Phillips said during the open meeting.

"When appropriately programed, IBRs can provide operational flexibility. And the ability of IBRs to perform with precision, speed and control could mitigate disturbances on the bulk power system," he added.

Commissioner James Danly called the rulemaking "long overdue" and the "most important action we've taken on reliability in the last year or two."

Commissioner Allison Clements said IBRs offer "an exciting opportunity for dynamic response and for increased operational flexibility."

She said she was disappointed that the final rule only directs NERC to consider requiring transmission owners to share data with IBR resources. She said NERC should require such sharing be required.

"The record in the preceding indicates the generator owners require data to support the modeling and performance requirements we are now directing NERC to create," she said. "I think it's kind of tough to make people bake the cake without giving them the recipe."

Clements said most current IBRs in place today should be able to meet the updated standards with simple software updates, but some older models may not be able to do so.

The rule directs NERC to consider exceptions for these older IBRs. "I hope to see such exceptions, as doing so will allow these older resources to continue to provide value to customers without compromising system reliability," she said. ■

FERC/Federal News

Market Monitors Endorse Call for Gas Reliability Organization

FERC Chair Touts Letter at Open Meeting

By James Downing

Market monitors from all of FERC's six jurisdictional grid operators have endorsed calls for a NERC-like gas reliability organization.

The monitors sent the commission a *letter* Oct. 10 endorsing the recommendations from the North American Energy Standards Board's (NAESB) Gas Electric Harmonization Forum, issued in July. (See *NAESB Forum Chairs Push for Gas Reliability Organization*.)

"In a time of unprecedented transformation, the reliability of the bulk electric system (BES) is increasingly dependent on the reliability of natural gas-fired generators," the monitors wrote. "As noted in multiple forums, recent winter storm and summer heat events have highlighted that the electric and natural gas systems do not function in an integrated manner when needed most, resulting in the loss of hundreds of lives and over $100 billion in economic damage from the 2021 and 2022 winter storms alone."

The letter was signed by PJM Independent Market Monitor Joe Bowring, SPP Market Monitoring Unit Vice President Keith Collins, CAISO Department of Market Monitoring Executive Director Eric Hildebrandt, ISO-NE Market Monitoring Executive Director David Naughton and Potomac Economics President David Patton, the market monitor for MISO and NYISO.

"We recognize that the report's primary recommendation is that an optimal solution likely requires federal legislation that creates a NERC-like organization for the natural gas industry," they said. "However, that outcome is uncertain. Given that uncertainty, we strongly support FERC's past, current and future efforts to improve the reliability of natural gas-fired generators within the North American BES."

FERC Chairman Willie Phillips highlighted the letter and its endorsement of the recommendations at the commission's regular meeting Oct. 19.

"The primary recommendation of the NAESB report is the establishment of a NERC-like organization for the natural gas industry," Phillips said. "And I welcome the support of all six independent market monitors, not only for NAESB's recommendations, but their encouragement that FERC, quote, 'take actions to use recommendations in this report.' I could not agree more."

The market monitors think gas-electric harmonization is a key issue that needs to be addressed, Bowring said in an interview.

"It's essential to maintaining the reliability of electric power markets as we … transition to more renewables," Bowring said. "We believe that gas is going to continue to be necessary. And it's essential that to the extent possible, we get better information, more transparency and more coordination between the two industries."

While the recommendations are national, Bowring said that they leave enough room for the different regional markets to adapt them to their specific needs.

"There needs to be somewhat different solutions, depending on the market, for sure," Bowring said.

For instance, PJM currently has a lower level of renewables than most of the ISO/RTOs, but it is facing a very high level of expected coal retirements and that means even more gas will be needed, he said.

Bowring said the most important recommendations from NAESB center on transparency. In PJM, it would benefit to know when pipelines invoke their tariffs to require generators to take the same amount of gas at all hours — which impacts power plant's ability to ramp up and down — and when they require strict adherence to their nomination schedules, because the gas trading day and power days do not align.

"One of the things that happened during Elliot was that PJM was not aware of these long nomination periods, and therefore they called on resources that couldn't get gas because they hadn't nominated it," Bowring said.

Electric-natural gas harmonization has been a concern for years. Winter Storm Elliot last December was just one of five winter reliability events over the past decade that would have benefited from improved coordination. (See *Déjà Vu as FERC, NERC Issue Recommendations over Holiday Outages.*)

Although the years of talk have not produced enough changes, Bowring said he was hopeful the momentum around the issue would lead to substantive reforms this time. Dealing with the issue will involve both industries coming together to develop rules that are consistent with their relative incentives.

"The business models are somewhat inconsistent. But there have to be ways to coordinate," Bowring said. "... The idea is not to force anything on the pipelines, or force anything on the generators. But I think it's in both sides' interest to coordinate. For whatever reason, it hasn't happened, and I'm hoping this is a wake-up call to both sides." ■

| *Shutterstock*

FERC/Federal News

FERC Allows Blackstone Subsidiary to Purchase 20% Stake in NIPSCO

Christie Says Sale Warrants Renewed FERC Scrutiny into Asset Firm Transactions

By Amanda Durish Cook

NIPSCO plans to shutter its Michigan City Generating Station in the 2026-2028 timeframe | *© RTO Insider LLC*

A Blackstone subsidiary is free to acquire an almost 20% stake in Northen Indiana Public Service Co. after FERC's consent Oct. 19.

FERC said Blackstone Investment Partner's Blue Buyer, owned by funds managed by Blackstone, can scoop up 19.9% of NIPSCO for $2.15 billion without setting off adverse market impacts (*EC23-99*). But the decision caused Commissioner Mark Christie to cast doubts again on FERC's review process and over the recent trend of big asset managers investing in the energy industry.

NIPSCO parent NiSource announced in late 2022 that it was looking for a buyer for a minority interest in the utility. CEO Llyod Yates said the sale will help pick up the tab on a 2040 net-zero emissions goal and approximately $15 billion in grid and gas infrastructure modernization and clean energy investments over the next five years. (See *NiSource Selling Minority Interest in NIPSCO*.)

The transaction includes a five-year hold harmless period for NIPSCO transmission customers to shield them from transaction-related costs.

Public Citizen and Citizens Action Coalition lodged a joint protest against the sale, arguing Blackstone will control two seats on the NIPSCO board of directors in addition to Blackstone already selecting a director of its choosing on FirstEnergy's board. They also pointed out Blackstone controls one seat on the board of Texas-based natural gas company Cheniere Energy and another two seats on the board of subsidiary Cheniere Energy Partners. They said Blackstone members are becoming too commonplace on the boards of FERC-jurisdictional utilities.

FERC said Blackstone's affiliations with energy companies won't harm competition. It pointed out that FirstEnergy operates in PJM, while the NIPSCO transaction involves the MISO footprint.

"Regarding concerns over Blackstone's ability to control boards of directors, we find that the proposed transaction will not adversely affect competition because our analysis … would not change even if Blackstone executives were to simultaneously serve on the boards of NiSource and FirstEnergy. This is because FirstEnergy's utility holdings are located in PJM, while the relevant geographic market for the proposed transaction is MISO," FERC said.

The commission said the sale won't raise market power concerns because although Blackstone owns transmission facilities in other markets and an intrastate natural gas pipeline, the transmission facilities will be placed under RTO control when they become operational and the pipeline is located in Texas, far from the NIPSCO service area, although partially in MISO territory.

However, FERC said it couldn't evaluate whether the acquisition would violate antitrust laws because its jurisdiction does not extend to the enforcement of the Clayton Antitrust Act.

Beyond that, FERC declined to take up Public Citizen and Citizens Action Coalition's arguments that the transaction stands to raise rates not only for Indiana customers but MISO as a whole because Blackstone will exploit the state's new right of first refusal (ROFR) law, which grants incumbent transmission owners first dibs to build lines approved by MISO. FERC said that contention was beyond the scope of its proceeding.

"Though joint protestors take issue with Indiana's ROFR law, they have not identified any way in which the Proposed Transaction will adversely affect vertical competition," FERC wrote.

NiSource said it will continue to control NIPSCO despite the transaction. It said that at the time it applied for the sale, affiliates of the Vanguard Group, T. Rowe Price Group and BlackRock each held more than 10% of NiSource's shares.

Christie Questions FERC's Narrow Evaluation, Investment Firm Acquisitions

Commissioner Mark Christie wrote separately to say he believed Blackstone's involvement in Midcoast Pipelines in Texas warranted NIPSCO and Blackstone to perform a vertical competitive analysis, which they did not file. Christie said the two's application should be considered incomplete.

"In recent years, the commission has rarely, if ever, required a vertical competitive analysis when approving section 203 applications — even where, as here, the merging entities participate in the same geographic market. The commission has relied on other evidence presented by the applicant to confirm that there are no vertical market power concerns. Although this may be a more administratively convenient approach, it ultimately does not conform to the commission's regulations," Christie wrote.

Christie said though he ultimately concurred with the commission's decision, it may be time to "revisit" FERC's policies when approving transactions — especially in the face of increasing partial acquisitions among utilities. He said he worried the motivations of investment firms run counter to public interest.

"I have previously written separately about my concerns over these partial acquisitions and what they may mean for the public interest, competition and reliability. There is an inherent tension between the profit-seeking motivations of large investment management entities and public utilities with the responsibility to provide reliable power at a just and reasonable rate," he said. "It is the commission's responsibility … to evaluate transactions involving these large investment management entities to determine whether they comport with the public interest. To do so… the commission must have regulations it can enforce that capture the concerns present in the types of transactions that occur today."

Public Citizen to File Letter with FTC Over FERC Antitrust Considerations

In an interview with *RTO Insider*, Public Citizen Energy Program Director Tyson Slocum said he shares Christie's frustrations with "FERC's insistence on utilizing such a narrow approach on reviewing mergers and acquisitions."

He said Public Citizen is "obviously disappointed" with the outcome of the docket and it plans to send a letter to the Federal Trade Commission about FERC "bizarrely" believing it lacks authority to consider violations of antitrust statutes when it decides mergers and acquisitions.

Slocum said it's a "clear violation" of antitrust laws for Blackstone executives to simultaneously serve on the boards of NiSource and FirstEnergy, even when they're situated in different RTOs.

"I think it's fair to say that NiSource and First Energy are engaged in some level of commerce that should be a flag for antitrust violations," Slocum said.

Slocum predicted a "sustained push" by private equity investors to acquire interest in utilities and "negotiate control over the board and other aspects of management." Utilities are experiencing "financial weakness" and slumping share prices because of high interest rates, he said, making it attractive for firms to step in.

"I think we're going to continue to see private equity firms playing a bigger role in public utilities," he said.

Slocum said he's also concerned such firms have "more opaque corporate structures and far less transparent public accounting" than utilities are tasked with. But he said there's only a slim chance FERC retools its mergers and acquisitions evaluation process if commissioners begin to view the transaction trend as a problem. ■

FERC/Federal News

Phillips Addresses 'Acting' Status as FERC Awaits Nominees

By James Downing

What's in a name?

That was the question FERC Chair — or "acting" Chair — Willie Phillips was asked at his press conference after the commission's open meeting Oct. 19.

The FERC *press release* announcing Phillips' elevation in January called him "acting chair," but that has no legal definition under the commission's governing statute. And the "acting" caveat was missing from the *order* President Joe Biden signed appointing Phillips. Phillips was confirmed by the Senate in 2021 to a term that ends June 30, 2026.

"Let me be clear: I work at the pleasure, and I serve at the pleasure, of the president," Phillips said in response to a question about the discrepancy. "And I'm honored to serve. On January 3, 2023, I was named the chairman and the leader of this agency. Nothing has changed."

This month, the conservative Institute for Energy Research released Biden's order, which it obtained in response to a Freedom of Information Act request.

IER said FERC took nearly eight months to respond to its FOIA request and that it did so under a court-ordered *deadline*.

"It is now clear … FERC had the document all along, but for some reason did not want it to see the light of day," IER President Thomas Pyle said in a statement. "It is also clear from the order that Commissioner Phillips is not the 'acting' chairman, as stated in the original FERC press release, but rather the full-fledged chairman."

Initially, Biden had tapped former Chairman Richard Glick for another term running FERC, but that was scuttled by Senate Energy and Natural Resources Chair Joe Manchin (D-W.Va.). (See *FERC's Work in 2022 Left in Doubt by Manchin*.)

Manchin and committee Republicans had criticized some of Glick's proposals on how FERC reviews applications to build natural gas pipelines and other infrastructure. Phillips got a much warmer reception from that committee in a hearing in May. (See *Senators Praise Phillips, FERC's Output at Oversight Hearing*.)

The White House told *E&E News* in January that Phillips would be acting chair until Biden appointed a "permanent" chair, and reiterated the "acting" designation this month.

The commission has added to the confusion: While press releases refer to Phillips only as "chairman," his *biography page* lists him as "acting."

Although appointment to FERC requires Senate confirmation, the appointment of the chair is the president's authority alone.

At the hearing in May, Manchin *told* Phillips "there is no such thing as an 'acting' chair," adding, "I'm glad you've been able to hit the ground running."

"Once the president says you're chairman, you're chairman," former FERC Chair Jon Wellinghoff said in an interview. "This 'acting' thing is all, you know, a big tempest in a tea pot, as they say."

The president can rescind the chair appointment at his discretion, which happened to former Chair Neil Chatterjee late in the Trump administration.

Chatterjee said in an interview that Phillips is going to be running FERC through the end of 2024 at least, after which the commission's leadership depends on the outcome of the next presidential election. The issue around the "acting" language had nothing to do with Phillips personally, but rather the White House seeking assurances from Manchin that he would not hold up Glick's ultimate replacement, Chatterjee said.

FERC Chair Willie Phillips | © *RTO Insider LLC*

Open Seats

FERC has gone more than 10 months without a replacement for Glick, and since then, Commissioner James Danly's term expired at the end of June, though he can stay on at least until the end of the year, when Congress adjourns. While the Senate schedule has only seven weeks left and some are thinking about a three-member regulator next year, Chatterjee, who was a longtime Senate staffer, said sometimes nominations can move fast.

"Things can be very, very slow," Chatterjee said. "But then there are times when lightning strikes, and they happen very quickly. So, I wouldn't rule it out. If there's momentum to do it, if it were clean, if there's a pairing that both sides were fine with, it could go very quickly."

In response to IER's claims, FERC spokeswoman Mary O'Driscoll said the president's order accurately reflects that Biden designated Phillips to lead FERC at the start of this year.

"Since he was named chairman, FERC has taken significant, bipartisan steps to enhance grid reliability, address the needs of environmental justice communities, certificate needed energy infrastructure and approve historic transmission reform," she added. "FERC is working — as it should — to secure a more reliable and sustainable energy future for all Americans."

After the open meeting, Phillips expressed pride in running an agency that regulates key sectors of the national economy.

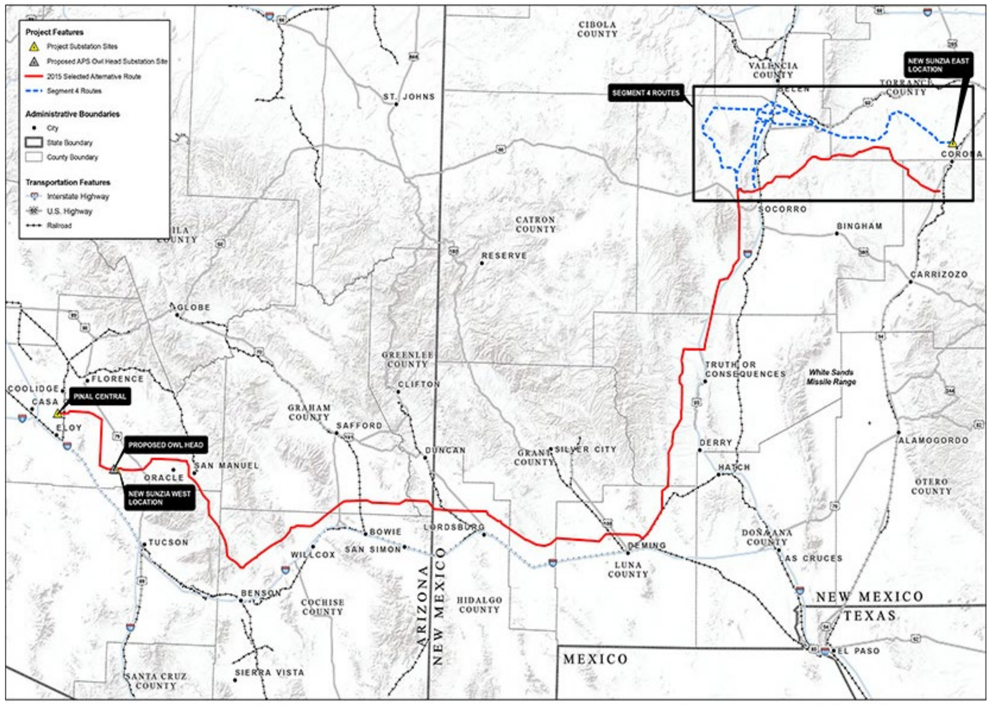
"I'm proud of the fact that since I became chairman, we have done significant work to make reliability job number one," Phillips said. "We have elevated the issue of environmental justice to be something that's not just whispered about, but actually talked about and confronted by this agency and throughout our industry."

Phillips also said his background growing up in rural Alabama and being the first Black man to run FERC influenced his job satisfaction. "I was just at Morehouse College … two weeks ago," Phillips said. "And I know that this is important because people tell me it's important to them. They see me and they know that they can do anything." ■

FERC/Federal News

FERC Approves Tariff for SunZia Transmission

By James Downing



The SunZia project is a high-voltage interstate transmission line intended to tap into rural and remote renewable energy in Central New Mexico for delivery into Southern Arizona. | *SunZia*

FERC on Oct. 20 approved SunZia Transmission's Open Access Transmission Tariff, which governs how the 550-mile HVDC line will offer new customers firm and non-firm point-to-point service (*ER23-2146*).

Pattern Energy is developing the transmission line, which is designed to ship renewable power from New Mexico to Arizona. Pattern is also an anchor-shipper on the line, developing several renewable projects in New Mexico.

SunZia has developed a monthly transmission rate of $8.18/kW, and it has based its annual, weekly, daily and hourly rates on that price.

The tariff includes interconnection rules for renewables that want to connect to SunZia, requiring customers to fund all incremental costs that are required to provide them service. In the event SunZia has to be taken out of service for a month or longer, the new interconnection customer will have to pay it back for the loss of any transmission revenue or any income it would have earned from the investment and production tax credits.

FERC found the tariff, including the generator interconnection procedures, to be just and reasonable and not unduly discriminatory or preferential.

SunZia's existing full capacity is subscribed to SunZia Wind (another Pattern subsidiary), but the tariff will be used for future transmission customers. The practice of basing all of its rates on the previously approved $8.18/kW monthly rate is consistent with FERC precedent, the commission said.

The merchant project also laid out plans to update its rates periodically, which is similar to mechanisms other merchant projects have, the commission said. The updates will let SunZia reflect changes in conditions or expenses.

FERC had issued a deficiency notice on the language requiring new interconnection customers to cover SunZia's losses from any outages that last more than a month, but it ended up accepting it.

"SunZia Transmission explains that, as a merchant transmission developer of an HVDC line, it faces considerable financial risks," FERC said. "Further, SunZia asserts that an outage would eliminate SunZia Transmission's ability to provide any service for the duration of the outage."

FERC has previously recognized that an anchor customer can assist merchant developers in meeting financial challenges unique to merchant development.

In this case, the financial futures of both the SunZia transmission line and the related SunZia Wind projects depend on each other and require certainty that losses from connecting a new customer would be recovered, FERC said.

"SunZia Transmission depends on monthly transmission service charge payments made by SunZia Wind to pay for its costs and to make debt service payments, and SunZia Wind depends on the continued availability of the transmission system to deliver energy in order to pay the transmission service charge and pay its own lenders," FERC said.

The firm would have to submit a filing to FERC to recover any costs under those provisions, so without commission approval, it would not be able to collect payments from interconnection customers to cover losses from an extended outage. ■

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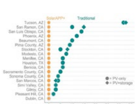

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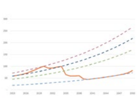

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CAISO/West News

FERC OKs Tx Swap Between Idaho Power, PacifiCorp

Transfer Will Aid Project to Deliver Wyoming Wind to Pacific Northwest

By Rich Heidorn Jr.

FERC on Oct. 19 approved a transmission asset swap between Idaho Power and PacificCorp as part of the companies' plans to develop a 300-mile-long, 500-kV line that will deliver Wyoming wind to the Pacific Northwest and hydropower to the Intermountain West (*EC23-111*).

In August, Idaho Power *said* it expected to begin construction work on the Boardman to Hemingway Transmission Project (B2H) this fall. The line between northeastern Oregon and western Idaho is expected in service by June 2026.

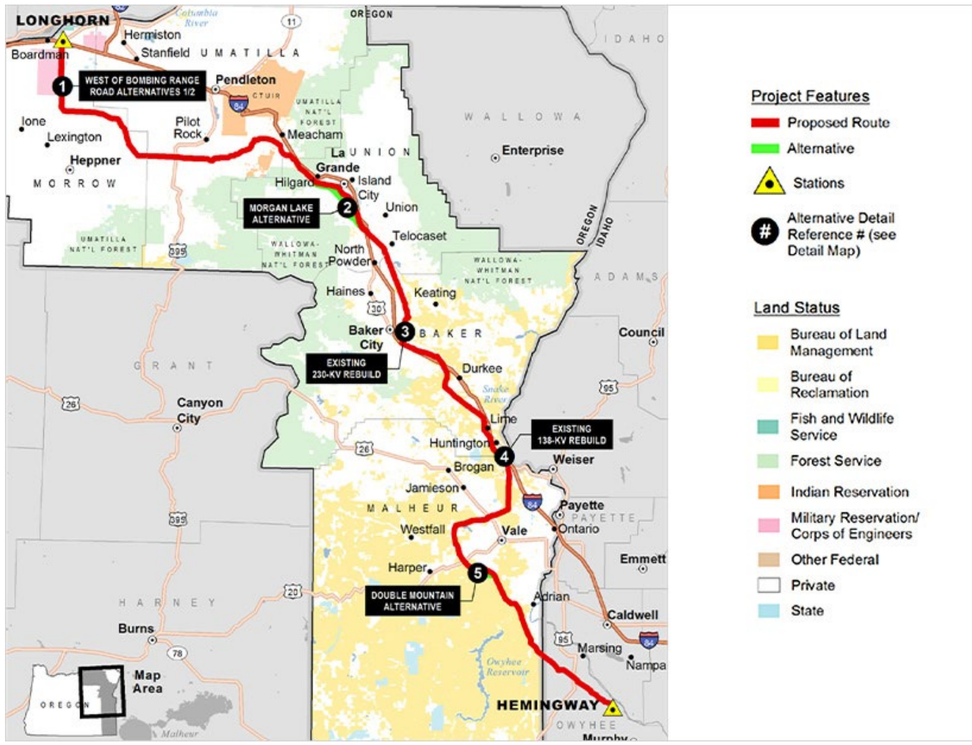
The two companies said they sought the transfer to improve the alignment of their transmission assets with their load service areas after the Bonneville Power Administration dropped out as a partner in the B2H project.

Although Bonneville had initially proposed to participate in the project to facilitate service to wholesale customers in southeast Idaho, it withdrew, choosing to take long-term firm transmission service from Idaho Power.

The transaction will give PacifiCorp 300 MW of west-to-east transmission capacity and 600 MW of east-to-west transmission capacity over the transferred facilities. Idaho Power will gain 200 MW of bi-directional transmission capacity over facilities through Idaho and more than 600 MW of capacity in the Goshen, Idaho, area to support network service from Idaho Power to BPA's southeast Idaho wholesale customers.

The commission concluded that the transaction would not harm horizontal competition because it does not involve any generation assets and that vertical competition would be unaffected because the transmission facilities involved will provide service under FERC-approved Open Access Transmission Tariffs. It also said the deal would not impact wholesale rates because the assets will be transferred at net book value with no acquisition premiums.

The commission conditioned its approval of the deal on the parties' completion of a memorandum of understanding to address Utah Associated Municipal Power Systems' (UAMPS) concern that the transaction could impact transmission service to UAMPS' members in southeastern Idaho.



Boardman to Hemingway transmission line project | *Idaho Power*

"We find that applicants have sufficiently addressed UAMPS's concerns, provided that they follow through on their commitment to enter into the memorandum of understanding," FERC said, ruling UAMPS' request to be held harmless "moot."

In a separate order, the commission also approved revisions to add the B2H project to Idaho Power and PacifiCorp's joint ownership and operating agreement over transmission facilities in Idaho, Oregon, Washington and Wyoming (*ER23-2463*).

The B2H project will run between a new switching station near Boardman, Ore., and the existing Hemingway substation near Melba, Idaho. Idaho Power *says* the project, which it identified in its 2006 integrated resource plan, is the least-cost alternative for serving its customers in fast-growing southern Idaho and eastern Oregon. PacifiCorp said the line will aid its service into northeastern Oregon and provide a second connection between the PacifiCorp-East and PacifiCorp-West balancing authority areas, currently connected only by the Midpoint-to-Summer Lake 500-kV line.

Idaho Power said the project will connect two regions whose peak production of clean power is mismatched with their peak demand. The Pacific Northwest sees energy demand peak in the winter, driven by heating loads, while its peak hydropower production is in the spring and summer. In contrast, electricity demand in the Intermountain West peaks in the summer from irrigation and air conditioning loads, while its wind energy peaks in the winter. ■

CAISO/West News

FERC Directs Ariz. Utility to Allow Solar Project to Interconnect

AEPCO Had Flagged Developer's Slow Pace and Potential Off-take Deal

By John Cropley

FERC is moving to grant a solar developer's request to force the Arizona Electric Power Cooperative to allow interconnection.

The *proposed order* FERC issued Oct. 19 gives AEPCO and developer THSI 30 days to negotiate the terms. If FERC finds the terms acceptable, it will issue a final order reflecting them. If the two sides are unable to reach agreement, FERC will prescribe the terms, consider the two sides' positions, then issue a final order.

Docket TX23-5-000 centers on the *Three Sisters Solar Project*, a 300-MW solar array with 300 MW/1,200 MWh of battery storage proposed in southeast Arizona by BrightNight and its subsidiary, THSI.

THSI formally submitted the interconnection request to AEPCO in November 2019. After multiple studies, the dispute arose. In May 2023, AEPCO notified THSI it had removed Three Sisters from the interconnection queue.

In June 2023, THSI asked FERC to direct AEPCO to provide interconnection, finalize the large generator interconnection agreement and restore Three Sisters to its position in the queue.

From early July to early September, AEPCO protested; three industry associations (American Public Power Association, Large Public Power Council and National Rural Electric Cooperative Association) sought to intervene, then also jointly protested; and THSI, AEPCO and the power authorities then filed successive arguments, protests and responses to each other's filings.

FERC's proposed order includes the following points and counterpoints by the two sides:

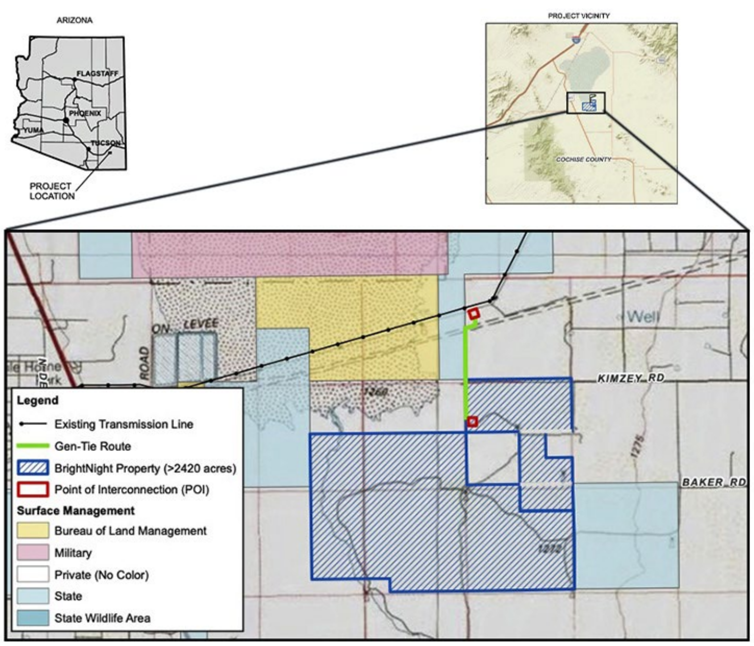
THSI said it originally proposed an Aug. 2, 2022, commercial operation date, then early this year proposed Dec. 15, 2025. It said AEPCO initially raised no concerns but on May 16, 2023, said the new date was a material modification that would necessitate a new interconnection study, and that Three Sisters had been removed from the queue.

Informal dispute resolution attempts were unsuccessful, THSI said.

THSI said all necessary interconnection studies had been performed and found no potential reliability issues and no significant need for network system upgrades. Further, the parties had already negotiated a large generator interconnection agreement.

So, there is little else to discuss, THSI said.

But AEPCO countered there are genuine issues of material fact because there is no certainty whether or how much Three Sisters would serve the wholesale market.



The Three Sisters Solar Project is located in southeast Arizona. | *BrightNight*

AEPCO said THSI's initial interconnection request made no mention of something that later came up in a state environmental review: a co-located green hydrogen production facility that would be an off-taker for the solar power generated there. This makes Three Sisters' grid output uncertain, it said.

But THSI has not secured the right to serve a retail load such as the hydrogen plant, AEPCO said, adding that an AEPCO member has state approval to provide power to the plant.

(THSI counters that there is no binding agreement with the hydrogen facility potentially to be built on site.)

AEPCO says there is no controversy over its willingness to interconnect with THSI, only over whether it must maintain THSI's position in the queue.

AEPCO questioned whether the public interest is served by allowing a developer to hold an interconnection queue position for more than five years, potentially to the detriment of other developers, for a project that might provide only behind-the-meter power to an industrial end-use off-taker.

AEPCO also laid out multiple reasons it believes FERC lacks jurisdiction to consider the matter. (The power associations made similar arguments. THSI offered counterarguments.)

AEPCO asked FERC to dismiss THSI's request with prejudice, preserve its right to update the studies and allow it to participate in evidentiary hearings if the matter is not dismissed.

In its proposed order, FERC explains why it does have authority to consider THSI's request, then explains why it is granting the request.

FERC said it finds the public interest would be served by directing AEPCO to provide interconnection service to THSI because precedent holds that transmission availability enhances competition in power markets, which should result in lower prices for consumers.

A potential future hydrogen facility does not necessitate new interconnection studies, FERC said, because THSI has made no changes to its 300-MW interconnection request.

Nor is there any genuine issue of material fact that would call for an evidentiary hearing, FERC wrote. ■

CAISO/West News

CAISO GHG Working Group Seeks Clarity on Problems, Definitions

Group Tasked with Identifying Issues Related to GHG Accounting in WEIM, EDAM

By Ayla Burnett

A meeting of CAISO's Greenhouse Gas Coordination Working Group on Oct. 19 illustrated the complexity Western stakeholders confront in addressing emissions in the region's expanding electricity markets — including the challenge of agreeing on basic definitions.

The meeting was the third for the group, a forum for stakeholders to discuss how the cost of GHGs should be accounted for in CAISO's Extended Day-Ahead Market (EDAM) and Western Energy Imbalance Market (WEIM). In both markets, the ISO must find ways to strike a balance between the needs of states that price carbon emissions in their economies and those that don't.

The working group was established to evolve GHG accounting design as a whole, with the goal of WEIM participants developing an accurate system to attribute generator emissions to load across state lines. Stakeholders have identified many uncertainties and are still in the beginning stages of defining current and potential problems that could occur after implementation of the EDAM, which will carry over the WEIM's current GHG accounting practices until needed changes are identified.

Of the 10 states participating in the WEIM, only two — California and Washington — price carbon through a cap-and-trade system, complicating the pricing of energy into and out of those "GHG zones."

Further complicating matters is that California and Washington operate separate cap-and-trade programs, increasing the potential for the over- or undercounting of GHGs when accounting for power transfers between the two states. Washington officials expect to decide soon whether to seek to join the joint California-Quebec carbon market, but any such linkage would occur in 2025 at the earliest. (See *Analysis Favors Wash. Linkage with Calif. Cap-and-trade Program*.)

CAISO's GHG working group is tasked with tackling complex issues around how to account for carbon emissions in the ISO's markets. | *Shutterstock*

CAISO/West News

The working group will also consider how CAISO's markets in the future might reflect obligations associated with "non-price" GHG policies, such as renewable portfolio standards, clean energy standards and renewable energy certificates.

Clarity on Definitions

Last week's meeting was devoted to discussing problem statements that were submitted by stakeholders that outline current or foreseeable issues regarding emissions attributions. Participants discussed how best to phrase and think about the problem statements and then identified action items to address them. The goal of a problem statement is to determine the root cause of an issue and come up with a solution.

Problems identified included how to account for and control emissions "leakage"; the potential double-counting of emissions between Washington and California; and determining if the current system's price formation accurately identifies total marginal GHG costs.

Much of the discussion dealt with the wording of the problem statements themselves, rather than trying to solve them. In Problem Statement 1, which describes the uncertainty around whether CAISO's market correctly identifies the "available surplus" of resources that may be attributed to a GHG zone, the definition of "surplus" was questioned.

"Buried in here is an assumption that there's an agreed definition of 'surplus,'" said Clare Breidenich, a consultant speaking for the Western Power Trading Forum. "We do not have that clarity from the California Air Resources Board."

The assumption is that "surplus" is generation in excess of the load for the market footprint outside of California, Breidenich added, and that it shouldn't necessarily be the same for all resource types, considering that entities operate differently in the market.

Jessica Zahnow of Puget Sound Energy suggested that looking at historical dispatches and attributions and running counterfactuals (the resource sufficiency evaluation in the WEIM) could help determine surplus and help stakeholders begin to understand if CAISO's market correctly identifies it.

The discussion about Problem Statement 2 prompted questions about use of the term "secondary dispatch," which has generally referred to the practice of a power producer directing output from a lower-emitting resource to a market that prices GHGs — such as California — while secondarily firing up an emitting resource to backfill load that would have otherwise been served by the cleaner resource. For states attempting to track and price carbon, the process results in the "leakage" of emissions in accounting for the true source of GHGs.

Problem Statement 2 states that the current attribution process still results in secondary dispatch and that the market lacks sufficient transparency into how often it is occurring. The discussion centered around identifying correct wording in order to best evaluate the issue. Stakeholders raised the concern that the statement assumes "secondary dispatch" and "leakage" are synonymous, when a producer may have to perform secondary dispatch for reasons not related to emissions.

Anja Gilbert, a lead policy developer at CAISO, suggested the two be differentiated and the problem be looked at in terms of leakage rather than secondary dispatch. Todd Ryan, principal market design analyst with Pacific Gas and Electric, echoed the concern.

"To my understanding, secondary dispatch can occur for a host of reasons, including economic displacement, which is the purpose of the Extended Day-Ahead Market and markets in general," Ryan said. "Leakage is a specific type of secondary dispatch that occurs when resources are inappropriately shuffled in terms of carbon intensity. [The terms] are often used synonymously, but I believe that is incorrect."

Kallie Wells, senior consultant with Gridwell Consulting, pointed out that the context of the conversation surrounding GHGs indicates that stakeholders are referring to leakage, not secondary dispatch, and that the differentiation should be made.

Gilbert added that a system of monitoring should be put in place to identify leakage when the EDAM goes live, given that CAISO and its stakeholders won't be able to assess its degree until after implementation.

At the suggestion of CAISO Market Engineering Specialist Kevin Head, the group clarified the problem statement to reflect secondary dispatch "that is not occurring as a result of economic displacement," but rather because of resource shuffling that leads to the inappropriate sale of non-renewable resources.

Further discussion indicated the need for an agreed-upon definition of leakage in the context of the statement and highlighted uncertainties about what type of leakage the problem statement refers to.

"What exactly are we talking about when we say leakage?" Wells said. "There's so much gray area, and I think until we are very clear about that, we're going to keep dancing around the same issue."

Premature Discussion?

Wells' comment was representative of a larger theme in the meeting: the need for more precision and a better understanding of how CAISO and its stakeholders should approach potential GHG-related problems in the absence of a way to test them.

Bonnie Blair, an attorney who represents the publicly owned utilities of the "Six Cities" in Southern California, echoed this concern.

"It's not clear to me, with respect to either of these problem statements, what market we're talking about" because the EDAM has yet to go live, Blair said. "We have the existing imbalance energy market, which does have a broad footprint and involves attribution of GHGs across [balancing authority areas]. We have the current day-ahead market, which is limited to the CAISO area and, I think, does not involve attribution of GHG impacts; and then we have the EDAM market design, which hasn't yet been implemented and is not going to be implemented for, I think, two and a half years."

Gilbert echoed the concern. "I think a complicating factor has been that we only have a live EIM market, and so without a live EDAM market, some of the proposed enhancements for EDAM that are looking to fix some of the issues with the WEIM enhancement can't be tested until they go live," she said.

An efficient way to view the problem statements, according to Gilbert, would be thinking about statements that could address potential enhancements that will need to be made in a future policy design phase.

Blair agreed, but she again emphasized the challenge of imagining problems in a system that does not yet exist.

"It provokes me to raise the question about whether it makes sense to try to focus now on fixing a problem that may or may not exist after the enhancements to the GHG process that are built into the EDAM design go into place," Blair said. "I question whether that may be premature."

The working group's next meeting is tentatively scheduled for Oct. 30, when it will continue to address the list of problem statements submitted by stakeholders. ■

Robert Mullin contributed to this article.

ISO-NE News

ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B

Some Stakeholders Concerned About Energy Storage Assumptions

By Jon Lamson

Transmission upgrades that are needed to avoid overloads in a fully electrified New England by 2050 could cumulatively cost between $22 billion and $26 billion, ISO-NE told its Planning Advisory Committee on Oct. 18.

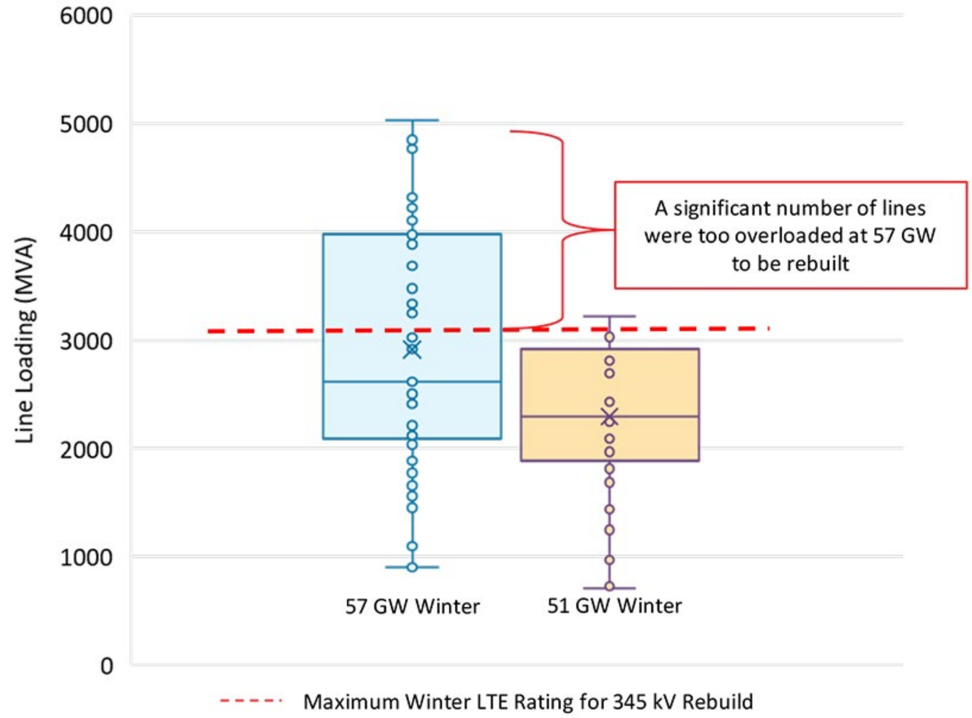
The RTO emphasized that limiting the 2050 winter peak from the anticipated 57 GW to 51 GW would save the region about $8 billion in avoided transmission costs.

The projections were part of the *results* of ISO-NE's 2050 Transmission Study, which was requested by the New England States Committee on Electricity in 2020. ISO-NE is now developing a process to better facilitate transmission infrastructure projects based on the findings.

The study focused strictly on thermal overloads on the system during peak load and did not include costs associated with interconnection, distribution, transient stability and other system needs. "The total transmission and distribution costs are anticipated to be much higher," it said.

"Reducing the peak load can significantly reduce the transmission costs," Reid Collins of ISO-NE told the PAC. The region could reduce this peak by either investing heavily in demand response, building insulation and heat pump efficiency, or by reducing the levels of electrification during the times of peak load, he said.

As a part of the study, ISO-NE identified a set of "high-likelihood concerns" that will need



Comparison of a 57-GW and 51-GW 2050 winter peaks | *ISO-NE*

transmission investment. These include the need to increase transfer capability from Maine and New Hampshire into the Boston area, and to boost import capability into the regions of Burlington, Vt., and southwestern Connecticut.

ISO-NE outlined a set of potential solutions for each of these concerns, including the potential of an offshore grid to address Boston imports. The study also found that the region will likely need many new transformers no matter where the new loads appear.

"It may be worth looking into ordering some of these up front, not knowing exactly where they're going," Collins said, noting the long lead times associated with acquiring

ISO-NE News

new transformers.

Some stakeholders expressed concern about the study's assumptions about the amount of energy storage on the grid in 2050. The study projected that the region would have just over 5,000 MW of nameplate capacity by then, which Collins acknowledged seems to be a low-end estimate. He added that most of the new storage assessed was of four-hour duration.

"There is already more battery storage expected to be online by 2033 than the 2050 Transmission Study's input assumption for 2040," Collins said.

While the study assumed that all oil, coal, diesel and municipal solid waste resources would be retired by 2035, it also assumed a significant remaining role for natural gas, with almost 17,000 MW of nameplate capacity expected for 2050.

Economic Planning for the Clean Energy Transition

Also at the PAC, ISO-NE's Patrick Boughan and Benjamin Wilson *presented* additional "sensitivity results" of the RTO's Economic Planning for the Clean Energy Transition pilot study, modeling different scenarios following requests from stakeholders.

The scenarios included running the study without the electrification of heating and transportation, with nuclear retirements, and with biodiesel as a carbon-neutral stored fuel. (See *ISO-NE Projects Decrease in Gas, Increase in Coal and Oil for 2032*.)

ISO-NE found that added demand from transportation and heating would increase the cost to load by 114% compared to the no-electrification base model.

"Because the additional heating and electrification load peaks in colder conditions, the additional load likely requires more stored fuel generation," Wilson said, noting these additional loads would greatly increase the expected need for oil generation, from 11 GWh to 834 GWh.

While ISO-NE anticipates that heating and transportation electrification would drive a 67% increase in electricity-sector emissions compared to the no-electrification scenario, Wilson noted that these emissions "are expected to be offset by emission reductions in other sectors."

In the scenario modeling nuclear retirements, ISO-NE found they would drive increased solar and wind generation but also increase emitting generation, especially during the interim years of 2030 and 2040. During these years, the model showed that nuclear retirements would lead to "a significant increase in gas generation and emissions."

In the biodiesel scenario, the RTO found that biodiesel — along with synthetic natural gas — would be a useful but expensive fuel for generation.

"Higher carbon prices or [renewable energy certificates] would be needed to allow carbon-neutral fuels to be utilized if they had to compete with existing emitting fuels," Wilson said.

Asset Condition Projects

Kyra Lagunilla of Rhode Island Energy presented to the PAC on three proposed asset condition projects totaling about $88 million. Lagunilla said the projects are necessary because of deteriorating and out-of-date transmission infrastructure that has led to poor performance on the lines.

The proposed line rebuilds are:

- the Rhode Island portions of the 115-kV M13 Pottersville-Jepson and L14 Bell Rock-Jepson lines, with a projected cost of $56.5 million and an in-service date of Q4 2025;
- the 115-kV S-171N Woonsocket-Hartford Ave and T-172N Woonsocket-Hartford Ave lines, with a projected cost of $22.3 million and an in-service date of Q3 2026; and
- the 115-kV E-183W Franklin Sq-Wampanoag line, with a *projected* cost of $10.6 million and an in-service date of Q4 2025. ■

ISO-NE News

ISO-NE Provides More Detail on Order 2023 Compliance

RTO Previews 2nd Phase of Longer-Term Transmission Planning Process

By Jon Lamson

ISO-NE is pursuing an alternative compliance pathway on FERC Order 2023 regarding storage resource interconnection, hoping to sidestep the need for "control technology," the RTO told the NEPOOL Transmission Committee on Oct. 16.

The all-day meeting ran nearly two hours longer than scheduled because stakeholders had so many questions on the proposed "independent entity variation" the RTO said is allowed by the order, which FERC issued in July to revise its ***pro forma*** generator interconnection rules. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

The proposed *alternate approach* would not require battery storage interconnection customers to install some kind of hardware or software preventing the battery from charging at times of elevated load. Instead, the RTO is proposing to "rely on security-constrained economic dispatch to govern the charging behavior in operations," Al McBride of ISO-NE told the TC.

Order 2023 allows storage interconnection customers to indicate the conditions in which they plan to charge their resource, while requiring control technology to ensure that a resource sticks to its studied behavior, McBride said.

"ISO believes that this approach is inconsistent with ISO-NE markets and would introduce significant operating inefficiencies compared with a more straightforward approach that is available to the region," McBride said, adding that FERC's approach fails to account for the addition of other storage resources at the same location and may limit charging more than is needed.

McBride said ISO-NE would have storage developers "identify a system load level above which they would not expect to charge a proposed battery storage facility"; the RTO would use this load level, instead of peak load, to study proposed facilities.

McBride also responded to stakeholder feedback on ISO-NE's proposed cluster study interconnection process. He said transmission owners should be required to attend the scoping meetings with the interconnection customers, clarifying the RTO's position on the issue. Order 2023 does not require TOs to attend these meetings, but several stakeholders have pressed ISO-NE to make this a requirement, saying it would save time and money and reduce the need for restudies.

Liz Delaney, of renewable energy developer New Leaf Energy, *presented* the TC with some compliance proposals aimed at minimizing the negative effects on projects currently in the late stages of the interconnection process.

Delaney said late-stage interconnection studies that have a "reasonable chance" of concluding prior to the start of the transitional cluster study should be able to proceed until 15 days prior to the start, likely April 30. If the late-stage studies fail to meet the 15-day-prior deadline, the projects should be given the option to enter the transitional cluster, Delaney said.

"These are mature projects whose development timelines will be delayed if they are pulled backwards into the transitional cluster study, impeding the region's ability to meet its clean energy goals on time," Delaney said, estimating this would impact about 15 projects totaling 2,700 MW of capacity.

Delaney added that ISO-NE should increase transparency around cluster study and cost allocation methodologies; tailor study deposits to project size; and calculate withdrawal penalties for projects in the transitional cluster study based solely on its costs, instead of those incurred in previous interconnection studies.

ISO-NE's compliance filing is due with FERC by Dec. 5, if it is not granted extra time. NEPOOL has *requested* a 45-day extension, which would push the deadline to Jan. 19.

Acting on Transmission Studies

Brent Oberlin of ISO-NE gave the TC a high-level *outline* of the second phase of the RTO's Longer-Term Transmission Planning project.

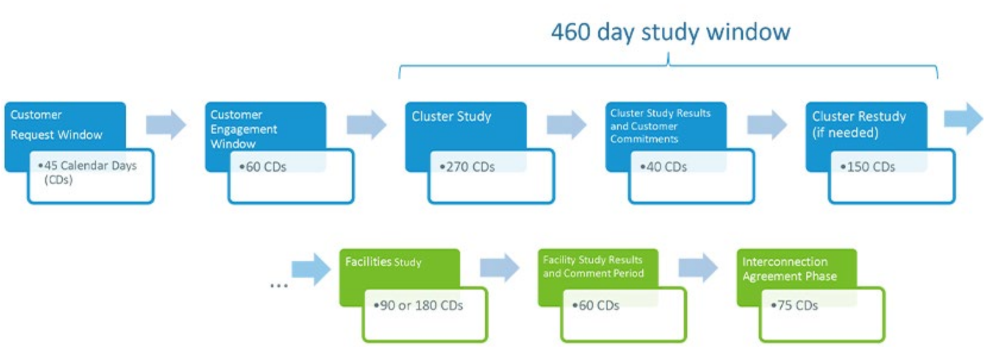
The first phase of the study led to the 2050 Transmission Study, which looks to identify the transmission upgrades needed to meet the region's anticipated 2050 peak load. (See related story, *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B*.)

ISO-NE is trying to streamline the process for the states to act on transmission needs identified in the long-term studies. Oberlin said the second phase of the process will establish "the rules that enable the states to achieve their policies through the development of transmission to address anticipated system concerns and the associated cost allocation method."

Under the RTO's proposal, the New England States Committee on Electricity would identify the transmission issues they want to address based on the findings of the studies. ISO-NE would then issue a request for proposals based on NESCOE's requests and select the preferred solution. If needed, NESCOE would have the ability to terminate ISO-NE's selected solution or submit alternate cost allocation methods.

Oberlin said ISO-NE is still considering whether some transmission projects should be assigned to the incumbent TO in the area, as opposed to going through an open RFP process.

ISO-NE hopes to file the necessary tariff changes with FERC in the second quarter of 2024. ■



ISO-NE's proposed cluster study cycle | *ISO-NE*

ISO-NE News

FERC Accepts ISO-NE Filing to Allow Storage as a Tx-Only Asset

Union of Concerned Scientists Among Groups Praising Decision

By Jon Lamson

ISO-NE can consider transmission-only battery storage as an option to address transmission system issues, FERC ruled Oct. 19. The commission-approved filing allows the operators of these assets to recover costs through transmission rates, while imposing tight restrictions around how the storage must be operated.

The tariff changes "will result in the selection of SATOAs [Storage as Transmission-Only Assets] only when those resources perform a transmission function, consistent with commission precedent," FERC wrote, noting that it had approved SATOA filings for MISO in 2020 and SPP in 2023.

SATOAs will be largely prohibited from participating in ISO-NE's markets in order to "minimize market impacts and ensure a SATOA does not receive dual recovery of its costs via both cost-of-service rates and market-based rates," ISO-NE wrote in its filing.

To be selected as a SATOA, battery facilities must be identified as the best solution in a transmission study, connect directly to pool transmission facilities and be controlled by ISO-NE. The RTO will also limit the total capacity of SATOAs to 300 MW across the system and 30 MW per substation.

"In these circumstances, SATOAs are properly characterized as transmission assets, and the costs of a SATOA are appropriately recoverable through transmission rates," FERC wrote.

ISO-NE's filing was supported by a range of stakeholder groups, with some calling on the RTO to go further in enabling batteries as storage solutions. Advanced Energy United (AEU) and the Union of Concerned Scientists (UCS) both called the filing a "first step."

"This is only a first step in expanding the capability of the transmission system through the deployment and recognition of energy storage," wrote Michael Jacobs of UCS, adding that the organization "urges the commission to take action to further expand opportunities for storage as transmission."

Jacobs added that storage should be included as an option to meet transmission needs identified in the interconnection process for large generators and said ISO-NE's set of constraints "omits opportunities for economic or reliability improvements."

Caitlin Marquis of AEU wrote that the SATOA capacity limits are "reasonable as ISO-NE gains experience and comfort with the use of storage as a transmission asset but should be evaluated over time to ensure they do not serve as an artificial and unnecessary barrier to SATOA participation."

Marquis said SATOAs should eventually be allowed to participate in ISO-NE's markets to tap into their full value.

"With the right guardrails in place, allowing storage to participate as both a transmission and market asset would optimize utilization of storage resources and maximize benefits to ratepayers," Marquis wrote.

But the New England Power Generators Association (NEPGA) called the limits "critical" to ensuring that SATOAs do not result in price suppression and operational issues.

"Price suppression is a real concern," NEPGA wrote. "When locational energy and ancillary service prices do not reflect the marginal economic cost of production, but instead are suppressed, for example, by cost-of-service resources indifferent to the economics of the market as 'price-takers,' the markets are less attractive to capital and thus less able to satisfy the common goal of cost-effective and efficient electric system reliability."

In approving ISO-NE's filing, FERC denied NEPGA's request that the RTO's Internal and External Market Monitors report on how effectively the SATOA limits mitigate adverse market effects. The commission said AEU's and UCS' calls for expanded uses for SATOAs were outside the scope of the proceeding.

FERC ordered ISO-NE, NEPOOL and New England Transmission Owners to submit the effective date of the SATOA changes, which ISO-NE did not specify in its filing. ■

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ISO-NE News

FERC Orders Section 206 Proceeding for New Brunswick Energy Marketing

By Jon Lamson

A Canadian company must prove it does not have market power in a geographic market that includes parts of northern Maine, or take steps to mitigate that market power, FERC ruled Oct. 19 (*ER14-225-009*).

New Brunswick Energy Marketing (NBEM) failed the wholesale market share indicative screen in three out of four seasons for the November 2020 to December 2021 study period, while passing the pivotal supplier indicative screen. FERC presumes the existence of *horizontal market power* when a seller fails one of the screens.

NBEM argued in its 2022 filing that a delivered price test and additional evidence indicate the NBEM does not have market power, despite the screen failure.

Based on the evidence it provided, NBEM urged the commission to "conclude that NB Energy Marketing has rebutted the presumption of horizontal market power and satisfies the commission's horizontal market power standard for the grant of continued market-based rate authority."

FERC responded that despite the additional evidence, "we conclude that New Brunswick Energy Marketing's failure of the wholesale market share indicative screen provides the basis for the commission to institute the instant section 206 proceeding … to determine whether New Brunswick Energy Marketing may continue to charge market-based rates."

FERC added it can initiate an investigation into market power while it reviews the additional evidence provided. It directed NBEM to provide evidence to justify "why the commission should not revoke New Brunswick Energy Marketing's market-based rate authority in the New Brunswick balancing authority area."

NBEM alternatively could propose measures to mitigate any market power, adopt FERC's default cost-based rates or submit different cost-based rates.

FERC told NBEM to file a response within 60 days of the order, and said it expects to issue a final decision by April 16, 2024. ■

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Grain Belt Express HVDC Line Clears Final State Approval

800-mile Line Will Save Tens of Billions of Dollars; Support is Vast, but Missouri Farm Bureau is Opposed

By Amanda Durish Cook

Invenergy Transmission

Chicago-based developer Invenergy Transmission's $7 billion, 800-mile Grain Belt Express HVDC line secured the final of its state approvals Oct. 12 with Missouri agreeing to the line's expanded design.

The Missouri Public Service Commission issued an Oct. 12 order granting the last of Invenergy's state siting approvals. The 4-1 decision allows the developer to amend its existing certificate of convenience and necessity to complete the line's more comprehensive design in two phases (*EA-2023-0017*).

Last summer, Invenergy Transmission said it planned to increase capacity of the Grain Belt Express to 5 GW by relocating and expanding the line's midpoint converter station from 500 MW to 2.5 GW and adding a 40-mile delivery line, dubbed the Grain Belt Express Tiger Connector. (See *Invenergy Announces Grain Belt Express Expansion*.)

Missouri regulators said increasing the merchant line's capacity, moving the converter station and adding the Tiger Connector will better interconnect "multiple regions to improve the reliability and resiliency of the grid for Missourians and national security."

"This will help guard against price spikes and outages such as those experienced by Winter Storms Uri and Elliot," the commission added. It said the HVDC converter can "serve as a critical grid asset to ensure grid stability."

The Missouri PSC expects the line to result in $17.6 billion in savings to Missouri ratepayers and $7.6 billion in social benefits.

"There can be no debate that our energy future will require more diversity in energy resources, particularly renewable resources. We are witnessing a worldwide, long-term and comprehensive movement toward renewable energy. The energy on the project provides great promise as a source for affordable, reliable, safe and environmentally friendly energy that will increase resiliency of the grid. The project will facilitate this movement in Missouri [and] will thereby benefit Missouri citizens," the Missouri PSC said.

Invenergy Transmission said the approval "provides the necessary certainty about power delivery to support ongoing and upcoming commercial contracting efforts." The company will finance and build the line in two phases, starting with the first phase between southwest Kansas and northeast Missouri. Invenergy reports it has acquired 95% of the easements for the first phase.

Grain Belt Express required approvals from Kansas, Missouri and Illinois.

The Kansas Corporation Commission in mid-June granted a similar amended approval to expedite the Grain Belt Express in two phases. The KCC said amending its approval was in the public interest "because it expedites the benefits of the project to Kansas, while maintaining all of the safeguards."

The Illinois Commerce Commission put its stamp of approval on Grain Belt Express in March.

"We thank the state leaders in Kansas, Missouri and Illinois who have thoughtfully considered the tremendous benefits of Grain Belt Express," Shashank Sane, executive vice president and head of transmission at Invenergy, said in a press release.

"Now that Grain Belt Express has received every state approval needed to construct the first phase and 95% of the main line easements are already acquired, we are more confident than ever that 39 communities across Missouri will be able to receive clean, homegrown energy that will save millions in lower electricity costs each year," Missouri Public Utility Alliance CEO John Twitty said in a statement.

Several other groups support the line, including industrial and manufacturing groups in Illinois and Missouri, clean power organizations, consumer advocates and a government office in Kansas dedicated to development.

"Lower energy costs are a major advantage for Missouri businesses, but it will only remain so if we can continue to increase our energy supply to meet demand and modernize the grid through state-of-the-art energy projects like the Grain Belt Express," Associated Industries of Missouri CEO Ray McCarty said in a statement. "The approval of this transmission line and the ability to bring five times as much power to Missouri as originally planned will not only help us tap a significant source of domestic energy, but also help improve reliability and affordability for the Missouri business community."

The Missouri Farm Bureau remains opposed to the line and expressed disappointment with the order.

In a statement, MOFB President Garrett Hawkins said the PSC's decision dismisses the right of landowners and puts "a lot of faith in [Invenergy] to do the right thing, when they have a track record of failing to do so time and time again."

"It is simply wrong that landowners along Invenergy's proposed route are forced to sell their land at a time — and to a buyer — not of their choosing, to forever host a line they do not want," Hawkins said. ■

MISO News

3 MISO Sectors Vote to Recommend $9B MTEP 23, Majority Silent

By Amanda Durish Cook

Just three of MISO's 11 member sectors voted to support the RTO's nearly $9 billion 2023 Transmission Expansion Plan (MTEP 23).

The Environmental, Transmission Owners and Transmission-Dependent Utilities sectors voted in favor of recommending MTEP proceed to the MISO Board of Directors for approval. Other sectors either abstained from voting or did not cast votes. No sectors registered opposition to the portfolio, so the motion to move MTEP 23 forward is considered passed. (See *MISO PAC Considers Lower, $9B MTEP 23 Transmission Package*.)

MTEP 23 now contains 572 new projects totaling almost $9 billion; 47% of that spending is destined for MISO South.

The low MTEP approval continues a trend of diminishing sector support for MTEP portfolios. In 2022, four sectors voted in favor of the $4 billion MTEP 22. In 2021, six sectors supported the $3 billion MTEP 21.

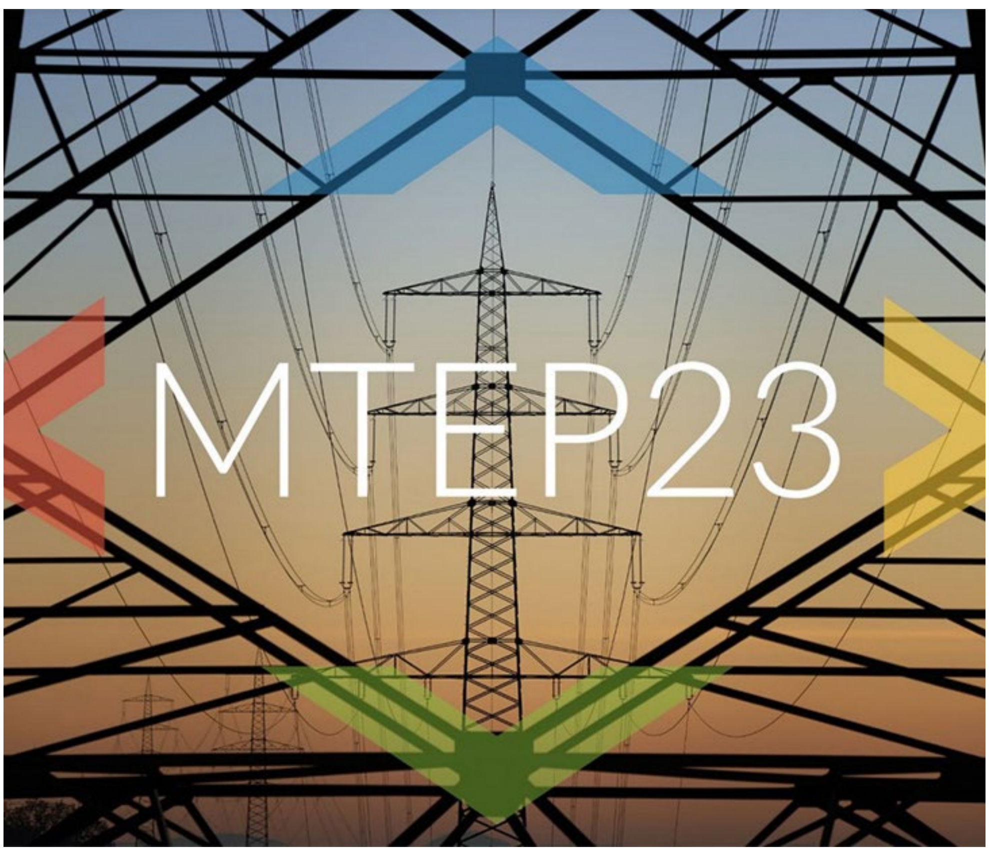
At an Oct. 18 Advisory Committee teleconference, WEC Energy Group's Chris Plante asked why so many sectors didn't register votes this year.

"For a sector to not submit a vote and not explain why, that's concerning," Plante said.

Three MISO sectors — the End-Use Customers Sector, Public Consumer Sector and the State Regulatory Sector — regularly abstain from voting on MTEP packages. This year, the Competitive Transmission Developers sector again joined in the abstentions.

LS Power's Brenda Prokop said the volume of "other" category projects and baseline reliability projects this year was cause for concern among the Competitive Transmission Developers. She also said there's little transparency into transmission owners' cost estimates for the sector to confidently back the slate of projects.

Energy consultant Jim Dauphinais said the End-Use Customers Sector doesn't weigh in on projects because it doesn't have the resources to conduct a thorough vetting of all MTEP projects. He said his members' positions on projects are best handled individually in state regulatory processes.



MISO's MTEP 23 report cover | *MISO*

MISO and its System Planning Committee of the Board of Directors held the first of two meetings Oct. 17 to devote more review and discussion to MTEP 23 and the stakeholder comments attached to the *draft report* this year. MISO's System Planning Committee typically holds just one meeting in November to consider the annual MTEP.

Senior Director of Transmission Planning Laura Rauch said, "given the magnitude of the projects," directors needed more time to consider the most expensive MTEP in MISO's history.

Rauch said most MTEP 23 projects are meant to solve reliability issues caused by localized load additions, especially in MISO South. She said MISO is not experiencing a regional, across-the-board increase in load that would justify regional project identification. She said MISO analyzed the largest MTEP 23 projects for potential as regionally cost-shared, market efficiency projects, but none could meet MISO's minimum 1.25:1 benefit-to-cost requirement.

Rauch told directors that members' comments this year on MTEP 23 likely will push MISO to consider HVDC and battery storage in future MTEP and long-range transmission plan (LRTP) portfolios.

She also touched on MISO delaying recommendation of the $260 million third phase of Entergy Louisiana's Amite South reliability project into 2024 so it can better scrutinize the project.

"Certainly, we don't think this is a bad project, but we need additional time for analysis," Rauch said. She said MISO will bring the project back to board members once it completes its alternatives study on the project.

Rauch said the slew of large, reliability-driven projects in MISO South won't impede MISO's plans to focus on the South region for the third portfolio of its LRTP. MISO remains committed to discussing the scope of the third LRTP in 2024, Rauch said.

MTEP 23 will go before the full MISO Board of Directors for approval at their quarterly meeting on Dec. 7 in Orlando, Fla.

Relatedly, MISO last week launched a new MTEP Planning Portal, the nonpublic platform members use to submit and update MTEP project proposals. ■

MISO News

ICC Staff: More to Consider in Possible Ameren Illinois Exit from MISO

By Amanda Durish Cook

An Ameren Illinois substation expansion in 2021 | *Ameren Illinois*

Staff from the Illinois Commerce Commission last week put their own spin on a year-old analysis showing how much Ameren's switch to PJM could cost MISO.

ICC staff said a previous study from Charles Rivers Associates (CRA) concluding it would cost Illinois more than $3.3 billion from 2025 to 2034 if Ameren were to leave MISO and join PJM needs more context for the commission to consider. They qualified CRA's cost analysis with potential benefits that the consulting firm didn't ponder.

The perspective was part of the ICC's *initial comments* under the notice of inquiry it opened this summer over the potential benefits of Ameren Illinois quitting MISO to join PJM. (See *Illinois Regulators Open NOI on Ameren MISO Membership*.)

Ameren commissioned CRA to complete the analysis at the direction of the ICC last year.

ICC staff said as a state with a retail access setup, Illinois may be a "better fit" with PJM's true capacity market than under MISO's residual capacity auction with "serious design flaws" and "wildly" fluctuating clearing prices. They said MISO's balancing market design only allows load-serving entities to purchase relatively small quantities of capacity and is best suited to vertically integrated states that "exert more control over generation and explicitly plan to meet their reliability needs," not for Illinois' reliance on competitive markets to determine resource expansion.

"Such an auction design is not complementary to Illinois polices and is a detriment to Illinois ratepayers. Staff acknowledges that MISO is taking steps to address issues with its capacity market. However, such efforts are still in the discussion phase and will likely not be implemented for some time," ICC staff wrote, noting the importance of MISO adopting a sloped demand curve in its auction.

Staff said unless MISO corrects its Planning Resource Auction, it could lead to continued price separation in Southern Illinois' Zone 4.

ICC staff also said benefits in the CRA study could have been contemplated on a longer-term horizon than 10 years since MISO itself uses 20-year future scenarios to plan transmission.

"Staff now believes that, while reasonable to assess initial impacts, this time frame may not capture all the benefits of new transmission over time and undervalues transmission assets," staffers wrote. "… If the benefits of transmission are considered over a longer and more realistic time frame, costs that are prohibitively high in the Ameren study could potentially be mitigated."

ICC staff said the CRA study discounts the reliability risks of Ameren remaining in MISO. They said MISO is set to experience significantly more solar and storage in its generation fleet than PJM. With that portfolio mix, MISO could more easily exhaust reserves during high demand sunrises and sunset periods, they said.

"Overall, the results point toward PJM having a more resilient system as compared to MISO, which would be a benefit in the join PJM case. This is a significant result and the inability of the MISO market to prevent unserved demand may be one of the primary reasons for considering a change in RTO participation," staff said.

Staff said CRA might be overestimating the impact of increased capacity costs under the PJM market. They said although the PJM market's sloped demand curve would cause Zone 4 to procure more capacity — at more expensive prices because of PJM's annual capacity product — the higher capacity prices could incentivize developers to build new generation or owners to delay retirements and ultimately lower capacity prices.

Finally, ICC staff said the study also assumed that because of their interdependence on Ameren, all utilities in MISO's Zone 4 will either stay in MISO or join PJM. However, staff said it's not a given that City Water Light and Power and the Southern Illinois Power Cooperative will follow Ameren's lead.

MISO declined to comment on the ICC staff's opinion of market shortcomings. The grid operator similarly had no comment when the ICC opened the notice of inquiry. ■

NYISO News

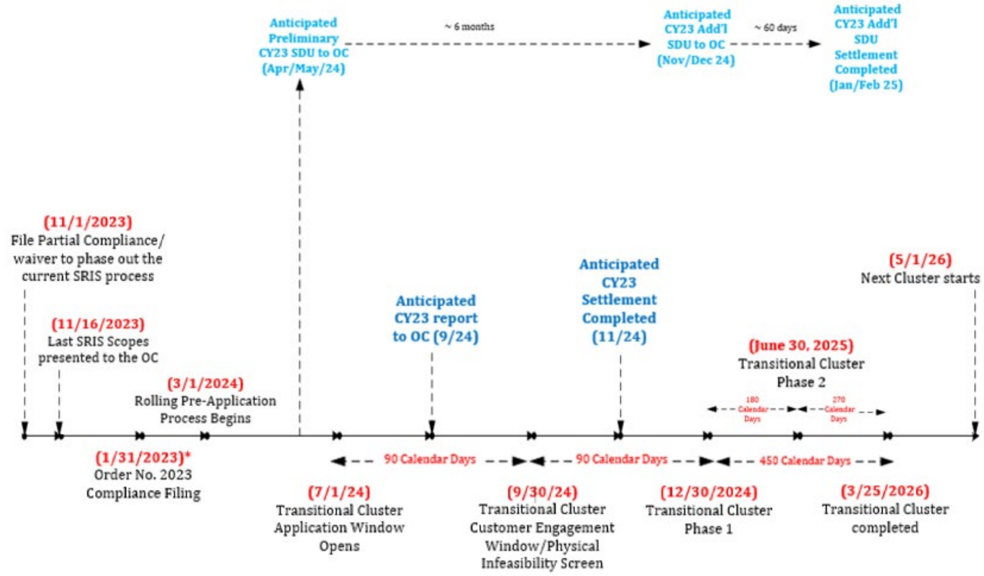
NYISO Plans Early November Filing for Partial Order 2023 Compliance

ISO Also Will Seek Deadline Extension

By John Norris

RENSSELAER, N.Y. — NYISO said it will submit a partial compliance filing for FERC Order 2023 early next month, aiming to get a head start on full compliance and minimize challenges associated with the transition to a new interconnection process.

NYISO attorney Sara Keegan told the Interconnection Issues Taskforce Oct. 20 that the ISO "wants to hit the ground running" in complying with FERC's order, which seeks to clear backlogged interconnection queues through a clustered study approach. (See *FERC Updates Interconnection Queue Process with Order 2023*.)



Theoretical Order 2023 transition and compliance timeline | *NYISO*

NYISO's partial filing will request that FERC eliminate the system reliability impact study (SRIS) requirement for pending queue projects, provide more options for pending projects to proceed through the queue and eliminate developers' option for detailed feasibility studies.

Thinh Nguyen, NYISO senior manager of interconnection projects, *said* the proposals "seek to streamline the study process" and remove redundancies by "eliminating any unnecessary parts of the study process."

Phasing out certain queue studies lets staff allocate their "limited resources more wisely," since they are not only working to comply with Order 2023, but also still reviewing projects moving through the ISO's current interconnection processes, Nguyen added. (See *NYISO Begins 2023 Class Year with Nearly 100 Projects*.) The ISO's last interconnection SRIS project scopes will be presented to the Operating Committee for approval this month.

Zachary Stines, director of wholesale market development at Borrego Solar, asked why NYISO was making only a partial compliance filing.

Keegan responded that the partial filing is "very limited," covering only what the ISO plans on doing during the interim period between December and the effective date of the full compliance filing.

"We want to be ready by the first cluster and be able to put all our resources into that, and not have to be winding down studies that provide no benefit in the new process," she said.

Nguyen concurred, saying later, "We want to avoid shooting from the hip and be able to get everything figured out as quickly as possible for developers."

Staff promised to continue the discussions and present stakeholder comments on the ISO's proposals at future IITF meetings.

Compliance Extension Request

Staff also reiterated that NYISO intends to seek an extension of the Order 2023 compliance deadline from Dec. 5 to the end of January or start of February. (See *NYISO to Ask FERC for Order 2023 Compliance Extension*.)

On Oct. 2, the New England Power Pool Participants Committee requested a 45-day delay of the deadline. That followed an Aug. 28 filing by SPP, PJM and MISO requesting that FERC delay the compliance date from 90 days after the final rule's publication in the Federal Register until at least 90 days after the commission issues a substantive order addressing arguments on clarification and rehearing (*RM22-14*).

The commission issued a notice Sept. 28 noting that rehearing requests in the docket were *rejected* after FERC failed to respond within 30 days. The three RTOs subsequently filed petitions asking federal appellate courts to review Order 2023. Other challenges have been filed by PacifiCorp, First Energy and Advanced Energy United.

Staff at the IITF noted that the ISO's motion could be filed irrespective of the commission's decision on the other RTOs' extension request.

"We may file before the commission decides, since we expected an order by now on the [other extension requests], and we will probably ask for an [extension] tailored to our particular circumstances," Keegan said.

Keegan said NYISO is looking for flexibility from the commission to minimize the impacts associated with transitioning to Order 2023's cluster study processes.

"It might be longer or shorter than other [requests]," Keegan added, "but we have a unique situation in terms of the timing of our queue reforms." He said the ISO wants to get everything into place before the start of the first cluster.

This need for flexibility was echoed in the compliance extension motions filed by other RTOs, who argued it would be difficult for them to both comply with FERC's directives and ask for more details on Order 2023.

"Requiring transmission providers to make compliance filings while many have pending requests for rehearing and clarification creates regulatory uncertainty and imposes a regulatory burden on some transmission providers and stakeholders as they seek to comply with the final rule while also undertaking their own RTO-specific reform effort," read the motion filed jointly by PJM, MISO and SPP. ■

NYISO News

NYISO Anticipates Increased Load in Western, Central NY

Q3 STAR Report Reiterates NYC Reliability Need

By John Norris

NYISO did not identify any new near-term reliability issues in its third-quarter Short-Term Assessment of Reliability (*STAR*) released Oct. 13, but it does anticipate significant load increases in western and central New York that could warrant more attention depending on how a previously identified supply shortfall in New York City is addressed.

In its previous STAR in July, the ISO identified a potential shortfall of up to 446 MW by 2025 because of peaker plants retiring to comply with state Department of Environmental Conservation regulations to limit nitrogen oxide emissions. (See *NYC to Fall 446 MW Short for 2025, NYISO Reports*.)

The most recent STAR notes that NYISO has reduced that figure by 20 MW, but "this potential reduction does not eliminate the need and has a negligible impact of the findings in" last quarter's report.

More significant, it said, "is the inclusion of additional large load projects primarily in western and central New York, many of which are currently undergoing a load interconnection study." It expects the state's large loads to increase by about 500 MW by 2025, reducing the state's reliability margin to less than 100 MW during normal operating conditions. "The rapid growth of large load projects poses a risk to the future reliability of the New York grid if it is not matched with the equivalent addition of new resources," NYISO said.

According to NYISO's *2023 Gold Book*, the large load projects are mostly new cryptocurrency mining and data centers. They also include the planned 1,250-acre Science & Technology Advanced Manufacturing Park (*STAMP*) in Genesee County in the west and a green hydrogen *facility* in Massena, along the Canadian border in the north.

"While there is potential for a deficient statewide system margin in 2025, the primary driver is the New York City deficiency already identified," the report said. "Depending on the solution to the New York City reliability need, the potential statewide deficiency may be mitigated."

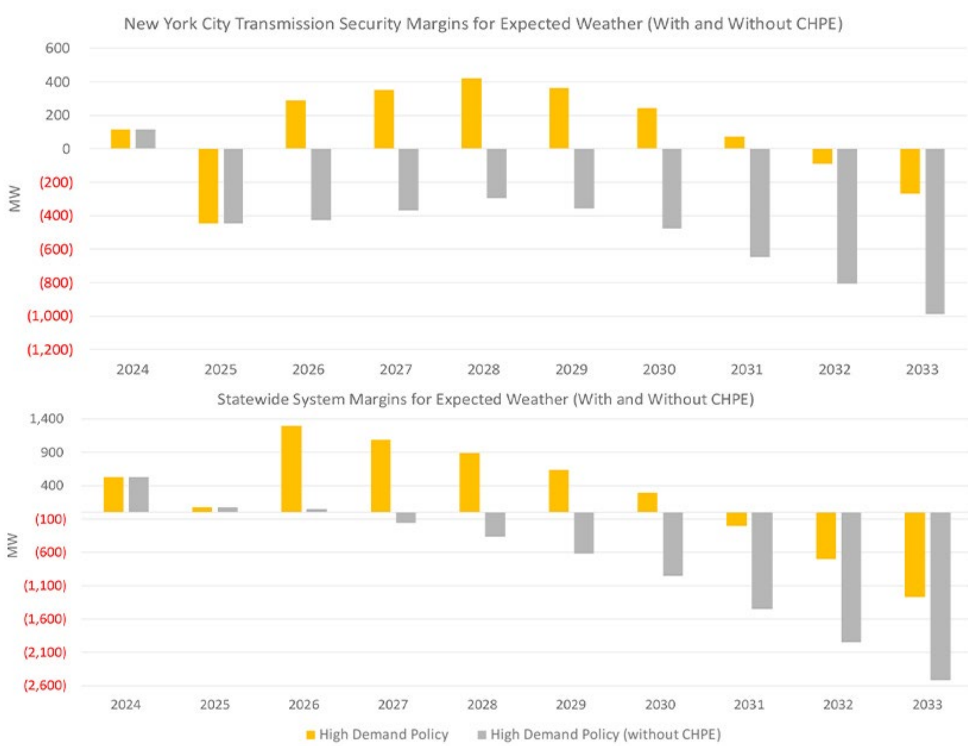
The planned addition of the Champlain Hudson Power Express transmission project would help the New York City shortfall, but it is not expected to go into service until summer 2026. (See *Champlain Hudson Converter Station Breaks Ground in NYC*.)

Without any additional resources, according to the report, a heat wave with temperatures of 95 to 98 degrees Fahrenheit in 2025 could lead to up to a 555-MW transmission security margin deficiency in New York City and over 1 GW statewide. The CHPE project would help alleviate that risk in subsequent years, but only until 2029, after which margins would decrease again.

The ISO is considering keeping certain peaker plants operational beyond the DEC's mandated retirement dates, as allowed under certain conditions set by the department, but only as a last resort if projects like the CHPE do enter service on time, the report said.

"As we have noted in previous STAR reports, if there are insufficient solutions to the 2025 reliability need, then [NYISO] may very well have to extend at least some of the peakers that are subject to the DEC's regulations," Zach Smith, ISO vice president of system and resource planning, said during the New York State Reliability Council's Executive Committee meeting Oct. 13. "We're working diligently to identify solutions and hope to publish a short-term report describing those solutions and our findings within the next few months."

The third-quarter STAR also flagged a transmission security issue in the Central Hudson area, driven by the assumed unavailability of certain generators because of the peaker rule. But because the relevant generators in the region did not provide complete deactivation notices before the STAR was conducted, the ISO only identified the issue for informational purposes and could not evaluate whether the deactivations would cause a reliability need. ■



Statewide and NYC transmission security margins with and without CHPE (2024-2033) | *NYISO*

Federal Lawsuit Challenges New York State Natural Gas Ban

By James Downing

A coalition of natural gas companies, homebuilders and unions have filed a lawsuit asking a federal court to overturn New York State's ban on natural gas hookups in new construction. (See *NY to Begin Banning Gas in New Construction in 2026*.)

The New York State Builders Association, National Association of Home Builders, New York Propane Gas Association, locals of the International Brotherhood of Electric Workers, Mulhern Gas Co. and others filed the suit at the U.S. District Court for the Northern District of New York. It seeks to apply the same logic as a successful challenge of a ban in Berkeley, Calif. The Ninth U.S. Circuit Court of Appeals said such bans are preempted by the federal Energy Policy and Conservation Act (EPCA). (See *Impact of Berkeley Gas Ruling Debated*.)

"As the only federal appellate court to have addressed this issue recognized, EPCA preempts state and local laws relating to the use of energy, such as gas, by covered appliances and equipment," the suit said.

The suit alleges the prohibition is inconsistent with the public interest and consumer choice and would shift energy demand to the power grid.

The ban only applies to buildings of seven stories or less in height and also exempts commercial or industrial buildings above 100,000 square feet in "conditioned floor area." But those exemptions go away starting in 2029, so it will apply to all new buildings.

| Shutterstock

"Plaintiffs support achieving the state's climate goals, but with the majority of New York's electric generating capacity coming from gas-fired power plants, banning gas in homes will do little if anything to advance those goals — and in all events, the state must comply with federal law," the lawsuit said.

Although the ban doesn't take effect until 2026, the plaintiffs said it is already chilling and undermining their businesses.

The EPCA was born out of the oil crisis in the 1970s and covers energy independence, domestic energy supplies and national security. It requires a practical approach to energy regulation, maintaining neutrality on energy sources and recognizing the need for a diverse supply of energy. The law includes regulations on appliances' energy efficiency, which are meant to be uniform across the country. EPCA expressly preempts state and local regulations on the efficiency and energy use of products for which it sets standards, leaving narrow room for concurrent state and local regulations.

New York announced its ban just weeks after the Ninth Circuit overturned Berkeley's ban, and the lawsuit argued that the state's rules do "exactly" what that court preempted.

EPCA has been changed a few times since the 1970s, including a 1987 amendment that specifically covers the preemption issue.

That change sought to reduce the regulatory and economic burdens on the appliance manufacturing industry through the establishment of national energy conservation standards for major residential appliances. Congress recognized that varying state standards would complicate design, production and marketing plans.

States can seek permission to establish their own standards, but that requires a showing of an unusual and compelling local interest and cannot be granted if the state regulation would lead to the unavailability of a product type or products of a particular performance class, the lawsuit said.

"New York's gas ban falls within the heart of EPCA's express preemption provisions," the lawsuit said. "The gas ban is a regulation concerning the energy use of appliances covered by EPCA in that it 'prevent[s] such appliances from using' fossil fuels, such as propane or natural gas."

The New York ban goes further into preempted territory than Berkeley's because in addition to banning gas piping it also bans gas appliances from being installed in new buildings. ■

NYISO News

NY Gov. Vetoes Planned Offshore Wind Transmission Act

Hochul Calls Legislation Duplicative of Effort Underway

By John Cropley

New York Gov. Kathy Hochul (D) has vetoed the Planned Offshore Wind Transmission Act approved by the state Legislature this year.

The legislation (A7764/S6218A) had two purposes: to establish a planning process for transmission capacity for future offshore wind generation and to allow an export cable for the Empire Wind project to run through parkland in the oceanside city of Long Beach.

Hochul said the first aspect is unneeded, as such planning is underway, and the second aspect is inappropriate, because renewable energy development needs to happen with support of the host community, not over its objections.

The Long Beach land matter was more immediate. Given the state of offshore wind development in New York state — almost the entire contracted portfolio, more than 4 GW in total, is in danger of cancellation — the reaction was predictable.

New York Offshore Wind Alliance Director Fred Zalcman said in a prepared statement: "The governor's actions are not matching her words. As a previously professed champion of offshore wind, we are once again mystified by the governor's decision to veto this essential authorization and to put another nail in the coffin of the Empire Wind project."

Equinor, which is developing Empire Wind with bp, said: "The veto of The Planned Offshore Wind Transmission Act undermines New York's commitment to the energy transition and the role offshore wind must play in achieving the state's renewable energy mandates. This decision sends another troubling signal to renewable energy developers following [the] action by the New York State Public Service Commission."

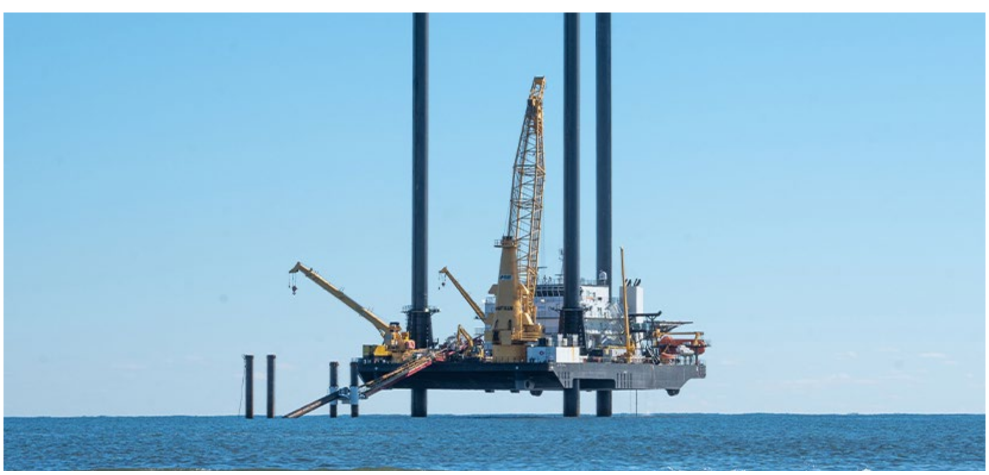
The PSC on Oct. 12 decided not to grant inflation-related cost adjustments to the Beacon, Empire and Sunrise offshore wind projects, along with 86 much smaller land-based wind and solar projects. (See *New York Rejects Inflation Adjustment for Renewable Projects*.)

Their developers had said they might not be able to commence construction without more money, as costs had increased greatly after they signed their contracts with New York state.

Long Beach became a rallying point because some residents do not want an underground cable running across the barrier island and their neighborhoods. (See *'What Did We Do to Deserve This?'*)

Under New York law, *conveying parkland* to a nonpublic entity or using it for something other than a park is called "alienation" and requires legislative authorization.

The language of the legislation authorized the city of Long Beach, at its discretion, to alienate roughly an acre of parkland. This left the choice to the city, and Hochul noted the city is opposed to alienation. But she went one step further in her veto message and denied even the choice to city leaders.



The liftboat Jill prepares cable installation for the South Fork Wind project off the Long Island shoreline in late 2022. | *South Fork Wind*

"It is incumbent upon renewable energy developers to cultivate and maintain strong ties to their host communities throughout the planning, siting and operation of all large-scale projects," she wrote.

Other projects have been snagged by the state's strong home-rule tradition, which can give local communities an outsized role in shaping large-scale development.

Critics of the route through Long Beach were pleased with the veto.

Rep. Anthony Esposito (R) cast it as a victory for a community fighting a deeply unpopular project being forced upon them.

He said in a news release: "Equinor's attempt to bypass Long Islanders' overwhelming opposition to the project by utilizing state legislators from New York City to force their corporate endorsed legislation on Nassau County was shameful. I am grateful Governor Hochul has listened to Long Islanders this time, but the fight to preserve our South Shore from Equinor's corporate greed will continue."

By contrast, the "planning" aspect of the Planned Offshore Wind Transmission Act was less emotional and more practical. It looks forward with the assumption that New York will want to expand offshore wind beyond the 9 GW of installed capacity goal that state law sets for 2035 and attempts to direct a more coordinated and cohesive transmission planning process to bring all that electricity to customers.

The legislation would have directed the New York State Energy Research and Development Authority to lead planning of independent transmission systems. Such shared transmission would minimize costs and environmental or community impacts, it said.

Hochul in her veto message said this is largely duplicative of existing planning requirements, such as New York's Accelerated Renewable Energy Growth and Community Benefit Act. The PSC has begun meeting its requirements, she wrote.

"To the extent that this bill's planning requirements are not duplicative, they would cause confusion by assigning contradictory and overlapping planning responsibilities to NYSERDA," she wrote.

"In light of these concerns, I am constrained to veto this bill." ■

PJM News

OPSI Annual Meeting Hears Calls for RTO Governance Changes

By Devin Leith-Yessian

COVINGTON, Ky. — The Organization of PJM States Inc. (OPSI) heard calls for increased transparency and new RTO governance rules at its annual meeting Oct. 17.

"Our energy sector is at a critical turning point, as renewable energy is more affordable, more reliable, more in demand than ever before and it is growing exponentially," Sen. Edward Markey (D-Mass.) said in a pre-recorded video for the meeting. "And we know we need more power lines to bridge the gap between clean power and the cities and towns that need it. We need a 21st century grid, not one recognizable by Thomas Edison, which is the one we have right now."

He said the Connecting Hard-to-reach Areas with Renewably Generated Energy (CHARGE) Act he sponsored in the Senate in July would increase public access, increase accountability, require independent RTO boards and limit "revolving door" appointments. He said the bill would also aid the clean energy transition while promoting reliability by requiring transmission planners to consider grid-enhancing technologies and account for severe weather scenarios, establish interregional minimum transfer requirements and build on the interconnection rules FERC put in place with its Order 2023. (See *Dems Introduce Bill on Transmission Planning, RTO Transparency*.)

"When operators get in a room and design the future grid, the doors are often closed to activists, to environmental justice groups and the general public. That has to change. My bill would require transparency and accountability in voting," Markey said.

Study Author Presents Recommendations on RTO Governance

The meeting also featured a discussion with Ari Peskoe, director of the Electricity Law Initiative at Harvard Law School, who authored a report last month arguing that current RTO governance preserves the status of larger incumbent market participants. The session was moderated by Michael Richard, of the Maryland Public Service Commission, and former FERC Chief of Staff Pamela Quinlan, principal of GQ New Energy Strategies — which she founded with FERC Chair Richard Glick this year.

The report, titled "Replacing the Utility Transmission Syndicate's Control," said representation of new and smaller market participants can be improved by revising the way RTO board members are selected, reworking membership sectors and expanding state and RTO filing rights.

Peskoe argued that the creation of a sixth member "innovation sector" would address the dilution of market entrants seeking to introduce new technologies that haven't been supported by larger companies he said dominate the stakeholder process, particularly in the lower committees, where they can use affiliate voting.

The report says the new sector could include "advanced transmission technology providers, distributed energy resource aggregators and storage developers." It notes that the commission issued a Notice of Proposed Rulemaking in 2002 that contemplated the six RTO membership categories, including an "alternative energy provider" sector (*RM01-12*).

Peskoe said FERC has pushed back against governance structures that give incumbent transmission owners the upper hand, particularly with orders related to storage and distributed resources. However, he said the commission hasn't connected the dots showing a connection between RTO decision making and the influence of investor-owned utilities.

The report states that RTOs' planning processes can give transmission owners an advantage in proposing projects and defining needs as local to limit the risk of a project being awarded to a non-incumbent developer through a competitive process. The amount of information available for supplemental projects at PJM's Transmission Expansion Advisory Committee has been an ongoing concern for state advocates.

He also said the transmission owners' filing rights — and the limited opposition their rate filings have seen from RTOs — subvert regional governance. He suggested that expanding RTOs' filing rights over regional cost allocation and local planning, as well as giving states filing rights, could counterbalance the special filing rights incumbent TOs possess.

Quinlan asked Peskoe what role the Independent Market Monitor has to play in moderating incumbent advantages and whether a counterpart on the transmission side could be a solution to the influence utilities have. He said the monitor does call out market design issues he believes should be addressed, but his recommendations have not always been

Michael Richard (left), of the Maryland Public Service Commission (PSC), and Pamela Quinlan, principal of GQ New Energy Strategies, moderated a discussion on RTO governance during the Organization of PJM States Inc. annual meeting on Oct. 17. | *© RTO Insider LLC*

adopted by the RTO and stakeholders.

He could envision a more limited role in the local planning process for a monitor to ensure the process isn't discriminating against any participants and to produce independent reports on the state of the network.

Jason Barker, Vitol's vice president of regulatory affairs, said PJM creates detailed voting reports showing how individual companies and sectors voted at the higher standing committees. He also argued that incumbent bias and the ability of larger companies to have staff at stakeholder meetings are counterbalanced by organizations that help members stay informed.

Peskoe said he isn't sure third-party representation and education are enough to counter the influence that companies with the resources to have representatives in the room wield in the stakeholder process.

LS Power Senior Vice President of Wholesale Market Policy Marji Philips said she doesn't believe companies that have not made significant investments in the PJM markets and region should have the same access as participants who have.

Peskoe responded that governance design should be focused on promoting competition, part of which includes displacing incumbents.

"We actually need to elevate new players more because the deck is stacked against them," he said. ■

Overheard at the OPSI Annual Meeting

COVINGTON, Ky. — Participants at the Organization of PJM States Inc. (OPSI) annual meeting debated PJM's recent capacity market filing and whether the RTO next needs to consider changes to its energy and reserve markets to ease the transition to increasing volumes of intermittent resources.

PJM Vice President of Market Design speaks at the Organization of PJM States Inc. (OPSI) annual meeting on Oct. 16. The panel also featured, from left, Katherine Peretick, of the Michigan Public Service Commission; Michelle Bloodworth, of America's Power; James Wilson, consultant for state consumer advocates; Paul Sotkiewicz, of E-Cubed Policy Associates; and David Scarpignato, of Calpine. | *© RTO Insider LLC*

Transparency Faulted on CIFP Filing

During a session discussing PJM's proposed capacity market changes, James Wilson, a consultant to state consumer advocates, said the Critical Issue Fast Path (CIFP) process that resulted in PJM's filing lacked the information sharing needed to adequately evaluate how specific provisions could impact rates or reliability. In particular, he said changes to the variable resource requirement curve would reduce the amount of unforced capacity (UCAP) available on the capacity market by around 25,000 MW. (See *PJM Files Capacity Market Revamp with FERC*.)

PJM Vice President of Market Design and Economics Adam Keech said the proposal would balance the reduced UCAP by reducing the amount of capacity that load will have to procure. Correlated outage risk, for instance, will be shifted from being on the demand side of the auction to supply.

"While, yes, the supply side is going down, I want to be clear that the demand side is going down," Keech said.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said he believes that the CIFP process tried to do too much too fast and said that when ISO-NE considered a shift to a seasonal capacity market — which was part of PJM's initial proposal which did not make it into the final filing — its stakeholder process spanned years with considerable data produced.

Sotkiewicz said changes to the capacity performance (CP) penalty structure and how it would interact with other market structures isn't fully understood. He noted that the proposal — which would redefine the annual stop-loss limit to be based on Base Residual Auction clearing prices, rather than the cost of new entry — comes on the heels of FERC's August approval of changes to the triggers that initiate the performance assessment intervals that expose resources to CP penalties. (See *FERC Approves PJM Change to Emergency Triggers*.)

Wilson said the CP changes could have a significant impact but that the amount of data that was presented during the CIFP process made it difficult for stakeholders to produce their own estimates of the effect on the capacity performance quantified risks that generators can include in their capacity offers.

"Is this a big thing or a little thing? I've never gotten a good answer," he said, adding that there's a potential for consumers to take on a significant amount of risk.

Michelle Bloodworth, CEO of coal lobby America's Power, said the risks present in the capacity market have been "vastly underestimated," particularly due the number of environmental rules recently enacted and being considered at the federal level. The coal resources present in PJM, which she said met 47% of the incremental increased demand during the December 2022 winter storm, would be particularly at risk if PJM doesn't consider those rules in its market design.

"With the coal fleet that we have we certainly don't want to cause more retirements," she said.

Both David "Scarp" Scarpignato, of Calpine, and Bloodworth said the shift to marginal effective load-carrying capability (ELCC) accreditation for all capacity resources would be an improvement. Scarp said ELCC goes beyond just addressing fuel security and would capture the risks of common mode failures.

PJM Chief Outlines Work to be Done Through Clean Energy Transition

PJM CEO Manu Asthana said the RTO is well positioned as it continues to adjust to the entry of renewable energy onto the grid, but there is more work to be done to ensure those resources keep pace with deactivating fossil generators and maintain reliability through extreme weather events.

At the top of PJM's efforts is the shift to a cluster approach for studying generation interconnection requests to clear a backlog with hundreds of GW in nameplate generation within a few years. He called it "an incredible engineering task" that is being aided by hiring additional planning staff and exploring ways of automating portions of the process.

He noted that PJM has also initiated new task forces focused on generation deactivations, reserve certainty and long-term transmission planning, as well as continuing efforts to harmonize the electric and gas markets.

Asthana said he's concerned that PJM's estimate that 43 GW of generation could retire due to federal environmental rules may be too low. The retirements are expected at the same time that load growth is poised to accelerate with hydrogen hubs and artificial intelligence fueling data center proliferation.

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While meeting the demand for that energy will require rapid development of new resources, Asthana said only a small number of resources that have cleared the interconnection queue have entered commercial service.

"We know that we have to continue to blaze through the interconnection queue and we're really laser focused on that, but there are a lot of issues beyond that which have to do with ... with cost pressures [and] supply chain pressures that may delay the rate at which those renewable generators show up."

In addition to seeking to accelerate the rate of new entry, PJM also will "advocate for what we think is critical: which is we're going to need thermal generation — which is going to include some coal and a lot of gas — to get us through this transition," he said.

Asthana said outages in other regions during extreme weather underlined how critical grid reliability is. Outages during the February 2021 storm in Texas caused an estimated $300 billion in lost economic activity, while Europe saw around 68,000 deaths last winter related to cold weather, some of which Asthana said was related to high energy prices causing people to not heat their homes adequately.

"The commodity that we provide to our customers is at the fabric of their everyday life," he said. "There's going to be no excuse if the lights go out for an extended period of time."

Panel Discusses Potential Changes to PJM Markets

Monday's sessions also included obstacles to the clean energy transition left unresolved by the CIFP filing and how to ensure that renewable resources are being developed at the pace they're needed.

Jason Barker, vice president of regulatory affairs for Vitol, said PJM's markets are the results of decades of fine tuning to the characteristics of thermal generators, which are not universally shared by the newer generation of inverter-based resources. Seasonal or time-of-day markets would more "surgically" capture their benefits and the introduction of storage promises to be a "game-changer" with the correct market design," he said. State policies could also play a major role in promoting the development of clean energy by setting a cost for carbon emissions, passing environmental legislation such as the Regional Greenhouse Gas Initiative and strengthening pathways for consumers to engage in power purchase agreements, he said.

"We think states should be more aggressive in setting these carbon valuations," he said.

Ensuring that renewable developments aren't held up in PJM's interconnection queue will also be necessary to allow new resource entry to keep pace with deactivations, Barker said.

Vice President of Planning Ken Seiler said that there are around 40 GW of projects with signed interconnection service agreements (ISAs) that have yet to go into service, while just 4 GW have been built so far this year, most of it gas-fired.

"We need to get generation connected to the system and we need to do it expeditiously," Seiler said during a Tuesday panel.

Abe Silverman, director of Columbia University's Non-Technical Barriers to the Clean Energy Transition Initiative, said the preliminary results of a survey he conducted of renewable developers with projects in PJM's interconnection queue suggest that are a multitude of challenges to getting steel in the ground even after receiving an ISA. One of the reasons he has heard cited is that some stages of the development process, including siting and permitting, cannot begin until developers have received an ISA from PJM. When there was more certainty about when their interconnection studies would be completed, developers could begin some preparatory work, but the uncertainty has increased alongside queue times. He also said developers have pointed to inflationary pressures, macroeconomic factors and the length of the queue in general.

"When we talk about the reliability issues of future retirements in PJM, we really need to talk about the ability to do interconnection as a critical reliability service," he said.

LS Power Senior Vice President of Wholesale Market Policy Marji Philips said that gas peaker plants will be required as a "last defense" for reliability, but are not receiving the price signals to stay in the market. One of the central challenges for gas resources remains the increased risk that they see over holiday weekends, when they may have to buy multi-day packages of fuel without knowing if they'll be dispatched and for how long.

She argued that ELCC accreditation works well for intermittent resources like wind and solar, but it doesn't capture the issues that affect gas-fired resource availability, namely dispatch uncertainty, fuel availability and winterization. The disparate contracts that generators have to procure their fuel and the circumstances under which it may not be delivered would be especially difficult to capture in ELCC, she said. PJM's CIFP proposal would expand the use of ELCC accreditation to all resource types.

"Peaker performance is dependent on dispatch," she said.

Calpine's Scarpignato said the interaction between state renewable energy credits (RECs) and PJM's energy market design results in many resources entering zero price offers and renewable resources being able to remain profitable even when energy prices are negative. For resources with fuel costs, he said that results in the capacity market becoming increasingly important for their revenues and makes them particularly sensitive to changes to the demand curve, which would be revised under PJM's filing at FERC.

Silverman said there is tension between states sending a price signal for meeting their clean energy goals and the wholesale energy markets and there will need to be harmonization between the two. Once states have enacted policies, he said they have to be able to understand how they will interact with PJM's market structures and how any changes contemplated by PJM could impact state goals.

Commissioner Danly Speaks on PJM Markets

Addressing attendees during Tuesday's lunch, FERC Commissioner James Danly said one of the most pressing issues in PJM's markets is ensuring that generators can reflect the costs and risks they see in taking on a capacity obligation.

"The first thing we have to do is make sure the generators are able to offer in costs to the markets that reflect their views of the risk assessment. To do otherwise is to place that basic function of a market into the hands of somebody other than the ones who have skin in the game, risks being assumed and profit being sought," he said.

PJM's markets should be insulated from external factors, including the "massive subsidies" created by states. He said that one could argue that some participants view PJM's markets less as a place to compete for energy prices than a forum for seeking subsidies, an issue he suggested is ripe for a filing and connected to the commission's past orders on the minimum offer price rule.

"One might even argue that the market is not even PJM or any of its mechanisms, the market really is these subsidies that are being chased after and people are attempting to harvest," he said.

Danly said the grid requires two types of infrastructure: transmission and gas pipelines, the latter of which he said will be needed under even the "most utopian view of what

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the resource mix may look like down the road." Building both on the timescale the infrastructure is expected to be needed will require states to undertake permitting reform, he said. In the meantime, PJM will have to position itself to adjust to the external difficulties of building transmission.

Questioned over the possibility of FERC extending its authority over pipelines to require winterization, Danly said that he doesn't believe there's a way for FERC to mandate changes. He said the potential for merchant pipeline development is slim given the financing issues established pipeline operators are experiencing.

Danly said the pipeline industry should be approached by groups like the North American Energy Standards Board (NAESB) with the recognition that its infrastructure was built with a different purpose in mind: maintaining the pressure needed to keep pilot lights on as, opposed to delivering large quantities of fuel to a relatively small number of gas generators.

Changes to Energy and Reserve Markets Discussed

Tuesday's sessions included a discussion of whether changes to PJM's energy and ancillary service markets are necessary to address issues PJM identified during the CIFP process and in its Resource Retirements, Replacements and Risks (4R) whitepaper released in February. (See "PJM White Paper Expounds Reliability Concerns," *PJM Board Initiates Fast-track Process to Address Reliability*.)

The whitepaper focused on a possible imbalance between thermal generation deactivations through 2030 and the development of new capacity, particularly intermittent resources that may lack the same capacity contribution per MW of nameplate. Initiating the CIFP process concurrent with the release of the whitepaper, the PJM Board of Managers focused the discussion on the capacity market, however many stakeholders said there are issues with other markets that could compromise reliability.

Much of the discussion was focused on the reserve market, which has seen a decline in the response rate since the two tiers of synchronized reserves were consolidated in a market overhaul implemented last October. The Reserve Certainty Senior Task Force (RCSTF) was created last month to explore further reworking several areas of the reserve market.

Sotkiewicz said generators have been receiving mixed signals from PJM during synchronized reserve deployments, with price signals indicating that they should decrease their output at the same time that PJM dispatchers are telling them to ramp up without any indication of what their output should be.

Rather than creating new products to account for the different characteristics of resources, he said PJM should ensure that the core needs met by reserves, frequency and voltage control can be fulfilled by the resources procured through the market. Not all of that capability needs to come from generation resources, he said.

PJM can tap into the largest battery on the grid — building air temperatures — by creating a market design that brings more load into the market. "We need to be forward looking with that and think outside the box," he said.

Susan Bruce, of the PJM Industrial Customer Coalition, agreed, saying that demand response, especially from smaller consumers, has been underutilized as reserves.

"It's a huge untapped part of the equation here. [We] should not just be thinking about the supply side. … We have a lot of load that's ready to be there," she said.

Referencing a presentation PJM gave outlining the responses it received from generation operators regarding their low response rate, Bruce said much of the issue appears to be based in operator error and incomplete understanding of how the markets function. Rather than focusing on market design changes, she suggested that providing education should be the starting point for addressing reserve performance. (See "Generators Cite Reasons for Low Synch Reserve Response Rate," *PJM OC Briefs: Oct. 5, 2023*.)

She cautioned that the urgency of ensuring that reserves are available shouldn't get in the way of having a full stakeholder dialogue to produce a fleshed-out solution that market participants understand and are prepared for.

"I think we all feel the press that solutions have to be here yesterday ... but at the same time when we go through the stakeholder process, it allows for issues to be vetted well and solutions to be well understood by the market," she said.

PJM's Becky Carroll said the RTO is considering ways of including demand more flexibly as it begins work in the RCSTF, where she said the focus is on thinking about all the tools that are available, as well as resource modeling and evaluating capability.

Independent Market Monitor Joe Bowring said some of the issues PJM cited in pushing for the creation of the RCSTF were misdiagnosed and he doesn't believe there's a need for a multi-year issue charge. He too expressed skepticism at the need for new products to account for the characteristics or flexibility of resources, stating that attempts to create ramping products in other RTOs have not been successful. Forward commitment and dispatch can fill the desire for more flexibility by allowing PJM to anticipate the need for reserves and call upon resources based on their ability to respond, he said.

Instead of creating more demand for reserves by increasing the amount it procures — a step PJM took in May when it increased the synchronized reserve requirement by 30% — Bowring argued that PJM should only pay resources when they have successfully responded to reserve deployments.

ReliabilityFirst's Brian Thiry said no single class of generators can meet all the reliability characteristics the grid requires. He said he is concerned that PJM lacks the incentives to maintain the diverse and flexible generation fleet it needs.

As an example, he said, an analysis of California's black start resources found that when existing resources retire they can be replaced, but grid recovery times could go from a number of hours to days.

"I encourage everyone to keep an open mind on all the capabilities, all the possibilities that are out there," Thiry said, mentioning dynamic line ratings, distributed energy resources, virtual power plants and new technologies like carbon capture and small modular reactors. ■

— Devin Leith-Yessian

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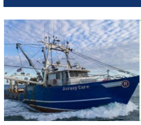

Opponents to NJ OSW Project Sue BOEM To Stop Project

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PJM News

FERC Delays Ruling on Vistra Purchase of Energy Harbor

Multiple Parties Raised Market Power Concerns over Merger

By James Downing

Beaver Valley Nuclear Power Station in western Pennsylvania. | *Energy Harbor*

FERC issued an order Oct. 13 giving itself more time to review the proposed $6.3 billion purchase of Energy Harbor by Vistra, saying it will now rule on the application by April 11, 2024 (*EC23-74*).

Commissioner James Danly said he would file a dissent on the order "tolling time for action" at a later date.

FERC issued a deficiency notice on the initial application in August.

The application had faced opposition from the Office of the Ohio Consumers' Counsel, who argued it would impact the retail market in the state. PJM's Independent Market Monitor and the U.S. Department of Justice urged FERC to ensure it did not lead to market power issues in the RTO. (See *Vistra's Deal for Energy Harbor Runs into Opposition at FERC*.)

Vistra owns 9,200 MW of fossil fuel generation in PJM's territory, including in Ohio and Pennsylvania, the two states where Energy Harbor's 4,000 MW (largely three nuclear plants) are located.

In comments filed in August, the Justice Department said FERC should focus on the interaction of Vistra's Richland plant, a 369-MW gas-fired combustion turbine in Ohio, with Energy Harbor's three nuclear plants. The plant runs 10 to 15% of the time, and Vistra often offers it near the clearing price, it said. Combined with the nuclear assets, which run all the time and are price takers, the Richland plant gives Vistra the ability and incentive to withhold power to raise the prices that the much larger nuclear plants get, the department said.

Both DOJ and the Monitor have argued FERC must look at smaller geographic markets because the nuclear plants and some of Vistra's existing generation are not able to sell to the entire PJM footprint because of transmission constraints.

Vistra has said that no local market power concerns exist because there are no frequently-binding transmission constraints that would limit its ability to sell power from the plants far and wide in PJM.

DOJ wants FERC to use a supply curve analysis in its review of the application, which is something the department argued for when the commission issued a Notice of Inquiry on its merger reviews in 2016. That NOI was never acted upon by FERC, and Vistra argued it would be unfair and lead to regulatory uncertainty to change the rules for its specific merger case.

In comments filed earlier that week, the IMM said that FERC's own deficiency notice recognized that the local market power issues "cannot be ignored."

Vistra has proposed selling off the Richland plant and a much smaller Stryker plant (a 16-MW oil-fired plant) to ease market power concerns, but the IMM said that week that the divestitures — even to a firm that owns no capacity in PJM — would do little to quell them. The sales would cut market power in some local markets created by transmission constraints, but the combined firm would still fail the three-pivotal-supplier (TPS) test too often.

"But the reduction in the number of hours that Vistra fails the TPS test is not large enough to conclude that the proposed divestiture of the Richland and Stryker units would resolve the market power concerns," the Monitor said. "Even with the divestiture, Vistra would have market power with respect to local constraints in the PJM market. Exercise of that market power to raise prices would raise energy market revenues for the Energy Harbor nuclear units."

Vistra also argued that its ownership of the three nuclear plants will put them in a better financial position, ensuring their continued operation and the local jobs and tax benefits they bring. Ohio Senate Majority Leader Rob McColley (R) wrote FERC a letter early this month extolling those economic benefits.

"All of Ohio will benefit from the operations and preservation of these plants by a capable and responsible owner like Vistra, which successfully operates other electric generation plants, including nuclear, across Ohio and the country," McColley wrote. ■

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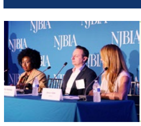

Car Industry: NJ Consumers Wary EV Adopters

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PJM News

Settlement over PJM Elliott Penalties Receives Broad Support

By Devin Leith-Yessian

A proposed settlement to reduce generators' nonperformance penalties for the December 2022 winter storm received support Thursday from PJM stakeholders, who urged FERC to approve it to reduce legal uncertainty (EL23-53, *et al.*).

A pair of Pennsylvania coal generators filed what is so far the lone protest against the settlement, which would reduce the penalties for nonperformance by nearly 32%. (See *PJM OKs 32% Cut in Elliott Penalties in Proposed Settlement*.)

In their *objection*, Chief Keystone Power and Chief Conemaugh Power argued that reducing the total penalties assessed against generators that did not meet their capacity obligations during the Winter Storm Elliott performance assessment intervals (PAIs) would deprive generators that invested in maintenance and on-site fuel of the Capacity Performance bonus payments they expected to receive under the tariff.

Under the CP construct, the $1.8 billion in penalties would be distributed to generators that exceeded their expected performance during the emergency conditions. The settlement would reduce the penalties to $1.23 billion by requiring bonus payment recipients, including the Chief companies, to return a portion of their share and resolve the 15 complaints generators filed against PJM related to the charges.

The Chief companies countered the argument made in several complaints that PJM had not followed the required steps before initiating a PAI by stating that market participants are able to access equal or superior weather and load forecasts than those that RTO dispatchers rely on and therefore should have been prepared for a potential emergency.

"Here is a settlement negotiated by PJM and a group of generating companies that failed to meet their obligations during a severe weather emergency because, among other things, they decided not to conduct necessary maintenance or procure firm gas deliveries in advance of the emergency and so were unable to generate when non-firm fuel was unavailable," the companies argued. "The fact that many of the nonperforming companies obtained fuel but failed to operate due to mechanical failures raises questions about maintenance and diligence in winterizing programs."

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They also argue that by resolving the complaints against PJM without a full investigation, the commission might foreclose on an opportunity to learn of any faults in the RTO's markets or generation fleet that could be improved on before they can disrupt system operations again.

If the commission were to approve the settlement, the Chief companies called for it to make the settlement binding only for those companies that were parties to the agreement.

"PJM proposes that approval of the settlement will relieve it from 'all claims' for its actions or inactions before, during and after the Winter Storm Elliott. That 'release' in conjunction with other settlement provisions is intended to preclude PJM from having to pay to performing companies the payments that are due under the tariff. While that may be appropriate for those who sign the settlement agreement, it must not apply to those that prefer to exercise their legal rights."

Support

In its *comments* supporting the settlement, the Coalition of PJM Capacity Resources — a group of generators that is party to the agreement — argued that it would avoid disrupting the RTO's markets with "unprecedented" penalties and protracted litigation that was likely to result from the complaints while still providing bonus payments to resources that had earned them.

The group said that many of the complainants sought a larger reduction, or complete rejection, of their CP penalties but agreed that avoiding years of uncertainty around the allocation of penalties and bonuses was preferable.

"If approved, this settlement will allow the parties to the Winter Storm Elliott complaints — PJM, the complainants and intervenors — to avoid the risks and burdens of time-consuming litigation so that PJM and market participants can focus their attention on capacity market reforms, maintaining reliability and encouraging investments in the PJM region," the coalition said.

It noted that 81 parties had signed on to the agreement with their support, with "many more" indicating that they don't oppose it, showing a belief among market participants that it is just and reasonable.

"Although the settlement was not agreed upon by all participants to the settlement negotiations, the settling parties include a broad array of market participants, including net nonperformance charge payors, net performance payment recipients, renewable resources, thermal generators, and small and large PJM market participants. This broad support across market participants is indicative that the settlement as a whole is just and reasonable," the coalition wrote.

Several companies submitted comments stating that they do not contest the settlement in the hope that it can provide market participants with more certainty about their bonus and penalty standings.

In its *comments*, Avangrid said its preferred outcome would be the implementation of the full penalties and bonus payments outlined in PJM's tariff, but it sees benefits in market certainty provided by the settlement.

"The primary driver for Avangrid choosing to be a non-contesting party is its recognition that there is value in settling disputes in a streamlined and timely manner," the company wrote. "Additionally, Avangrid hopes in earnest that this potential value of settling these issues — such that members may focus on forward-looking, and not retroactive, initiatives — comes to fruition." ■

PJM MRC/MC Preview: Oct. 25, 2023

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

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

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Endorse proposed *revisions* to Manual 3A: Energy Management Systems Model Updates and Quality Assurance (QA) with the aim of clarifying how transmission owners should submit modeling data to capture outages that aren't linked to have a network model ticket. The changes, resulting from the manual's periodic review, also aims to clarify definitions of monitored priorities. (See "Periodic Review Revisions to Several Manuals Discussed," *PJM OC Briefs: Oct. 5, 2023*.)

C. Endorse proposed *revisions* to Manual 19: Load Forecasting and Analysis to require that load forecast adjustments include a 15-year forecast and more granular hourly load history to be provided. Electric distribution companies and load-serving entities (LSEs) also would be required to include a public document outlining how the forecast adjustment was calculated. (See "More Extensive Guidelines for Load Forecast Adjustment Endorsed," *PJM PC/TEAC Briefs: Oct. 3, 2023*.)

Endorsements (9:10-10:30)

1. Capacity Offer Opportunities for Generation with Co-located Load (9:10-9:30)

PJM's Jeff Bastian is set to review a *proposal* to define how generators with co-located load not interconnected with PJM's grid may enter into the capacity market. The language would allow the resource to retain its full capacity interconnection rights, rather than reducing its accreditation by the amount of energy supplied to the co-located load and would define the generator as an LSE for the load, subject to all applicable credits and charges. (See "Stakeholders Endorse Proposal on Co-located Load," *PJM MIC Briefs: Aug. 9, 2023*.)

The committee will be asked to endorse the proposal.

2. 2023 Reserve Requirement Study (9:30-9:45)

PJM's Patricio Rocha Garrido will review the recommended *values* for the installed reserve margin (IRM) and forecast pool requirement (FPR) produced by the annual reserve requirement *study* (RRS). The IRM, which sets the targeted capacity level above expected loads, would rise from 14.7% for the 2026/27 delivery year in the 2022 study to 17.6% for the 2027/28 DY. The FPR, which includes forced outage rates, also would increase from 9.18 to 11.65% for the corresponding delivery years. (See "Stakeholders Endorse Reserve Requirement Study Values," *PJM PC/TEAC Briefs: Oct. 3, 2023*.)

The committee will be asked to endorse the recommended values.

3. Outage Coordination (9:45-10:05)

PJM's Paul Dajewski will review a *proposal* and corresponding manual revisions to increase coordination between utilities and PJM to identify potential extended transmission outages. (See "Stakeholders Endorse Outage Coordination Manual Revisions," *PJM OC Briefs: Oct. 5, 2023*.)

The committee will be asked to endorse the proposed solution and corresponding revisions to Manual 38: Operations Planning.

4. Local Considerations in Net Cost of New Entry (10:05-10:25)

PJM's Gary Helm will review a *proposal* and corresponding tariff revisions to create a fifth cost of new entry (CONE) area for the Commonwealth Edison (ComEd) zone, breaking it out of CONE Area 3. The proposal is the result of a stakeholder discussion on if and how to account for state or local policies that impact the inputs for calculating CONE for a region, in this case focusing on the Illinois Climate and Equitable Jobs Act. (See "Creation of Fifth CONE Area Endorsed," *PJM MIC Briefs: Oct. 4, 2023*.)

The committee will be asked to endorse the proposed solution and tariff revisions. Endorsement from the Members Committee also is to be considered Wednesday.

Members Committee

Endorsements (1:25-1:35)

1. Local Considerations in Net Cost of New Entry (1:25-1:35)

PJM's Gary Helm will present a *proposal* and corresponding tariff revisions to create a fifth CONE area for the ComEd zone.

The committee will be asked to endorse the proposed solution and tariff revisions. ■

— Devin Leith-Yessian

Markets+ Stakeholders Make Gains on Governance

By Elaine Goodman

As SPP moves closer to finalizing the governance structure of its Markets+ day-ahead offering, the grid operator hosted an Oct. 19 webinar focused largely on a committee that will nominate members of the Markets+ decision-making body.

The committee will put forth candidates to serve on the five-member Markets+ Independent Panel (MIP), described as the highest level of authority for Markets+ decisions. The SPP Board of Directors will have oversight of the MIP.

MIP members must be independent from Markets+ participants and stakeholders. Panel members will be elected by the Markets+ Participants Executive Committee (MPEC), which will consist of representatives of each Markets+ participant and stakeholder.

A slide presented during an MPEC meeting in Portland, Ore., in August led some to mistakenly believe the nominating committee was being eliminated, according to Paul Suskie, SPP's executive vice president of regulatory policy and general counsel. Instead, the nominating committee will have an expanded role to also conduct "periodic reviews" of the Markets+ governance structure.

"It's not eliminated. It's actually expanded in its duties," Suskie said during the Markets+ governance webinar.

The name of the committee has been changed to the Markets+ Nominating and Governance Committee (MNGC) to better reflect its roles and eliminate confusion. Most stakeholders who have weighed in support the committee's expanded role.

Day-ahead Competition

The discussion comes as competition is heating up between two day-ahead offerings: SPP's Markets+ and CAISO's Extended Day-Ahead Market (EDAM). Governance is an issue that often arises when the two are compared, raising debates about independence. (See *In Contest for the West, Markets+ Gathers Momentum – and Skeptics*.)

In August, CAISO filed tariff revisions to implement EDAM with FERC. (See *CAISO Files EDAM Proposal with FERC*.)

The Markets+ governing documents will be included as an attachment to the Markets+ tariff, expected to be filed with FERC early next year.

But before the FERC filing, the governing documents will be presented to the MPEC next month. Stakeholders still have a chance to submit proposed amendments through Nov. 17.

SPP staff will recommend that the MPEC approve tariff language at its December meeting. From there, it's expected to go to the interim MIP, with the SPP board of directors voting on it in January.

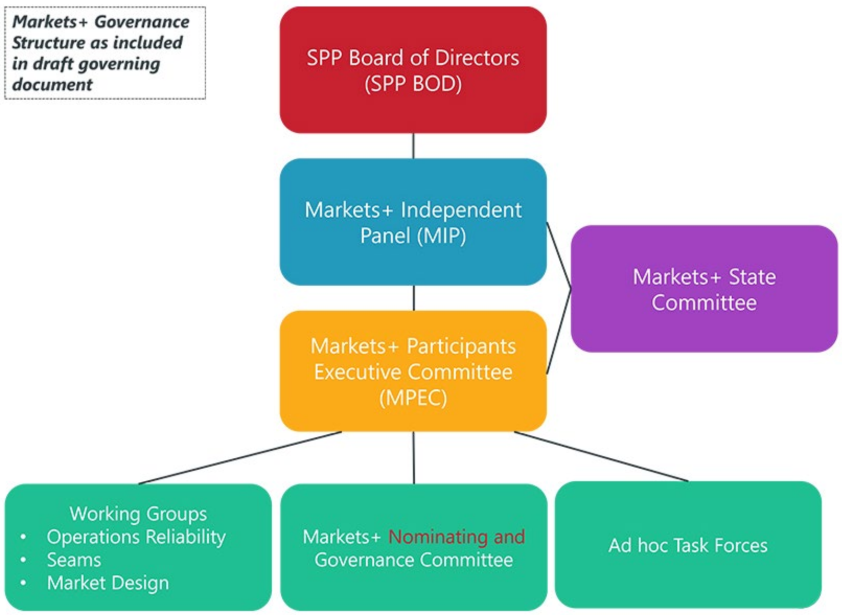

Diagram illustrates the draft governance structure for SPP's Markets+. | *SPP*

The newly dubbed MNGC will include a representative from each of 12 sectors, such as independent power producers, cooperatives, municipal utilities and federal agencies. The latest governance proposal has added a representative of state agencies and provincial entities.

Suskie said one issue still to be worked out is how to prevent the MNGC from becoming geographically lopsided. As an example, he said, the sectors could potentially all select a representative from Colorado.

SPP is looking at ways to avoid such a scenario.

"It's something we're going to think through, reach out to some folks, and maybe propose something for the MPEC to consider," Suskie said.

The MNGC will nominate candidates to vacant seats on the MIP. Candidates may also be nominated with support from at least 20% of MPEC representatives.

The MNGC will also be able to make recommendations to the MPEC regarding governance changes. Proposed changes would need a four-fifths vote from the MIP before being filed with FERC.

State-based Advisory Panel

Yet another committee in the governance structure is the Markets+ State Committee (MSC), an advisory panel to the MIP, MPEC and task forces or working groups.

As now proposed, MSC members will come from each state in which a Markets+ participant has generation or load. Some stakeholders have argued that states with MSC representation should be required to have load.

BPA supports the participation in MSC of states with "generation or load." In written comments, BPA said the committee's advisory role "is strengthened by the inclusivity of states in the Markets+ footprint, both generation and load."

But AEPCO argued that only states with load in the Markets+ footprint should be eligible to participate in the MSC.

"A state with only generation should not be eligible, as a single generator in a non-contiguous state that contracts with Markets+ could otherwise trigger MSC eligibility," AEPCO said in written comments. ■

FERC Approves Extension for Oklahoma Solar Farm


| Bureau of Land Management

FERC has granted a solar developer's request for a 28-month extension of its commercial operation deadline, finding that it acted in good faith to develop the facility (*ER23-2603*).

Twelvemile Solar Energy requested the extension in August for its planned 100-MW solar farm in Oklahoma that will interconnect with the SPP system. It executed a generator interconnection agreement with SPP and Oklahoma Gas and Electric in January 2019, reflecting a December 2020 commercial operation date. That date was extended in January to this December because of schedule disruptions caused by the COVID-19 pandemic and U.S. trade restrictions on imported solar equipment.

The developer said the pandemic and trade action created a "constrained" market in which demand for utility-scale PV panels considerably exceeds available supply.

The GIA included a provision that it could be terminated should Twelvemile Solar fail to meet the commercial operation date for three consecutive years.

FERC said in an Oct. 19 ruling that the request meets the commission's criteria for granting waivers: The developer acted in good faith to develop the facility in accordance with the GIA; the waiver was limited in scope and applied only to the deadline; it addressed a concrete problem; and granting it would not result in undesirable consequences. ■

— Tom Kleckner

SPP News

FERC OKs NextEra Ask to Recover Abandoned Tx Costs

Commissioner Christie: Order 679 May Force Commission to Overlook 'Used and Useful' Requirement

By Tom Kleckner

FERC on Oct. 13 granted NextEra Energy Transmission (NEET) Southwest's request to recover 100% of "prudently incurred costs" to construct a competitive transmission project in New Mexico, should the project be abandoned or cancelled for reasons beyond its control (*ER23-2630*).

The commission agreed with NEET Southwest's contention that the project faces certain regulatory, environmental and siting risks beyond the developer's control that could lead to its abandonment. FERC said its abandoned plant incentive will address those risks by protecting NEET Southwest.

"Thus, we find that NEET Southwest has demonstrated a nexus between its requested incentive and its planned investment and that NEET Southwest has tailored its incentive rate request to its identification of risks and challenges associated with the project," the commission said.

SPP awarded the NextEra subsidiary the Crossroad-Hobbs-Roadrunner 345-kV project in July. The project, 135 miles of double-circuit 345-kV lines at either end of the Hobbs generating substation, is estimated to cost $291.6 million and has a proposed in-service date of May 2026. (See *SPP Awards NextEra 3rd Competitive Project*.)

In August, NEET Southwest filed a request with FERC under Section 205 of the Federal Power Act and the commission's 2012 policy statement on transmission incentives for incentive rate treatment.

The commission previously accepted the developer's 2017 filing for a formula rate designed to be incorporated into SPP's tariff. In its order, FERC also granted NEET Southwest's request for several incentive rate treatments: a 50 basis point return on equity incentive for participating in an RTO or ISO; a regulatory asset for prudently incurred pre-commercial and formation costs for later recovery; and a hypothetical capital structure of 60% equity and 40% debt until its first transmission project is commercialized.

Commissioner Mark Christie concurred in a separate statement, but also called for FERC to revisit "the array of incentives offered to transmission developers." Those include construction-work-in-progress and hypothetical capital structure incentives, and RTO participation adders.

"A core principle of utility law and regulation for decades is that consumers can only be forced to pay costs for assets that are 'used and useful' to them," he wrote, noting that under *Order 679*, the commission may have to overlook that principle to address the "substantial challenges and risks" in building transmission facilities.

Christie said he previously questioned the commission's determination of "whether 'substantial challenges and risks' exist when granting the abandoned plant incentive and other incentives has become nothing more than a check-the-box exercise." ■

The Crossroads-Hobbs-Roadrunner competitive project. | *SPP*

SPP Markets and Operations Policy Committee Briefs

Members Endorse PBA, ELCC, Rejecting Compromise Position

LITTLE ROCK, Ark. — SPP stakeholders last week approved two revision requests following a lengthy discussion that set resource adequacy policies.

The Markets and Operations Policy Committee first rejected a compromise position recommended by two stakeholder groups. They urged that one of the two revision requests, which details SPP's proposed performance-based accreditation (PBA) policy (*RR554*), be modified to use seven years of historical data, rather than 10, in calculating conventional resources' accredited capacity.

That motion received only 57% approval during MOPC's two-day meeting. Replacing the seven years of historical data with 10 years resulted in 84% approval for RR554 and *RR568*, which lays out an effective load-carrying capability (ELCC) policy, with all 14 transmission owners voting yes.

RR568 is a response to *FERC*'s rejection earlier this year of SPP's first attempt to add ELCC (the amount of incremental load a resource can dependably and reliably serve during peak hours). The revision reduces a three-tiered structure to just two, firm and non-firm transmission service. Staff will study only firm service in its ELCC analysis. (See *FERC Grants Rehearing of SPP Capacity Accreditation Proposal*.)

SPP's Market Monitoring Unit initially proposed five years of historical data but settled on the seven-year compromise during a September meeting with the Resource and Energy Adequacy Leadership (REAL) Team. (See *SPP REAL Team Compromises on PBA, ELCC Revisions*.)

"It's important that we have an accurate assessment of historical performance. We feel that [five years] is a much more accurate representation of an assessment period," MMU's executive director, Keith Collins, said. "As you think about going forward, are you doing things to improve the performance of your resource?"

Smaller utilities sided with the 10 years of historical data, saying it would give them and their smaller fleets more time to meet resource requirements.

"They're facing an entirely different risk profile in this RTO going forward, and that can't be overstated enough. The risk now is substantial in the loss of a unit over a period of time," Golden Spread Electric Cooperative's Mike Wise said.

"It is a balancing act," SPP's Casey Cathey, senior director of grid asset utilization, said. "It's a question of if we can provide more accurate, responsible performing resources through maybe a shortened timeframe, then that might lessen the socializing of an increase in [planning reserve margin]. But to the extent that we can better accredit those resources, then it more accurately applies that to the individual resources as opposed to socializing them."

MOPC also approved a Supply Adequacy Working Group policy paper on demand response (DR) that will be converted into a revision request and the stakeholder group's direction on fuel assurance. Both motions passed with more than 91% approval.

The SAWG plans to develop a policy that facilitates diverse DR programs by considering the potential for increases in large loads that may claim its accreditation. Its members say SPP must accurately accredit DR resources according to their reliability contribution and develop qualification standards to drive consistency.

The group also voted to develop policy that incorporates PBA weighting based on critical system periods and considers modifications to the out-of-management-control exceptions related to fuel-related outages. The SAWG also will consider a policy for PBA and ELCC adjustments to reflect new reliability investments and it recommends SPP improve operational dispatch strategies to start units before extreme cold weather and keep them online.

Cathey said he hopes the changes can be implemented before the 2026-27 winter season.

SPP's Casey Cathey kicks off the discussion of PBA and ELCC policies. | © *RTO Insider LLC*

Sunflower Waiver Request Rejected

Members rejected Sunflower Electric Power's request that four byway transmission upgrades be allocated 100% to the entire pool, based on their regional use, under a cost-allocation methodology that FERC rejected earlier this year.

SPP's largest transmission owners pushed back against the measure, saying allocating costs of existing facilities should not be done on an ad hoc basis by the RTO's state regulators. They said deconstructing the grid operator's highway/byway process with one-off reassignments sets a troubling precedent for future requests.

Eight of 12 TOs voted against the measure and six others abstained. Half of the transmission users voted for RR584. It failed with 50.8% approval.

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"There's no actual methodology associated with this. This is just some power facilities being moved into the tariff and being elevated to highway funding without clear direction or a repeatable process also being applied to it," Southwestern Public Service Co.'s (SPS) Jarred Cooley said. "We at SPS are very concerned that this is going to set an ad hoc precedent on how cost allocation is performed moving forward on an ad hoc basis. It's a repeatable process and without a methodology or a firm waiver process."

FERC in July unanimously reversed a 2022 decision that established a process for SPP to allocate "byway" transmission projects on a case-by-case basis without prejudice. (See *FERC Reverses Course on SPP Byway Cost Plan*.)

Sunflower, a "wind-rich" cooperative that long has felt unduly burdened with transmission costs for renewable energy that benefits others, has filed a rehearing request with FERC and asked the U.S. Court of Appeals for D.C. to review the case (*ER22-1846*).

The cooperative submitted its waiver in November 2022 from SPP's base-plan allocation methodology for upgrades between 100 kV and 300 kV, or byway projects. The process allocates one-third of the cost of byway projects to the RTO's full footprint, with customers in the transmission pricing zone where the project is built being allocated the rest. "Highway" projects — those larger than 300 kV — are allocated RTO-wide.

The Cost Allocation Working Group (CAWG) approved Sunflower's waiver request in May. In September, it recommended to SPP state regulators that they approve and send to the board a revision request (*RR584*) allowing SPP to make a Section 205 filing at FERC that permits the four Sunflower upgrades be regionally allocated on a prospective basis.

The Regional Tariff Working Group approved RR584 later in September in a 9-5 vote, with five abstentions.

SPP's Ben Bright, the CAWG's staff secretary, said the group intends to continue working on the issue with the Regional State Committee (RSC), which has ultimate decision-making authority over SPP's rates.

"The filings at FERC are still in limbo," Bright told the MOPC. "Once those are more complete, then we will take up looking at a more comprehensive process, whether that be in the form of a waiver or just some sort of an assessment."

The CAWG intends to make the same recommendation during the next RSC meeting.

Project Withdrawn, ITP Passes

MOPC approved two stakeholder groups' (Transmission Working Group, Economic Studies Working Group) 2023 Integrated Transmission Plan (ITP) and its *10-year assessment*, but not before members withdrew a $92 million, 48-mile, 115-kV joint economic project in Nebraska between the Western Area Power Administration's Rocky Mountain Region and the Nebraska Public Power District.

The TWG's motion failed with 53% approval when the project was included but passed with 97% approval when it was removed. The move gives SPP staff more time to find the right solution.

The Municipal Energy Agency of Nebraska's Brad Hans motioned to add a notice to construct (NTC) for the Alliance-Victory Hill project. According to the assessment, the line would be congested by several elements in the area. Staff evaluated several alternatives, but timely rebuilds would be with non-SPP facilities, limiting viable solutions.

The 2023 ITP addresses reliability and economic issues on its seams. It recommends NTCs for 44 projects. The portfolio includes 150 miles of new transmission — 51 miles for 345-kV lines — and 93 miles of rebuild for a total engineering and construction cost of $735.5 million and a reduced 40-year adjusted production cost of nearly $3 billion.

Natalie McIntire, representing the *Sustainable FERC Project* and Natural Resources Defense Council, compared the portfolio's size with that of recent MISO portfolios approaching $10 billion and suggested a third more aggressive future be used.

"The levels of expected increase in electrification [and] the rapid change in our generation mix across the country, seem to me to indicate that we're going to need a lot more transmission. We're going to need a much more robust grid," she said. "I'm just concerned that SPP is going to find themselves behind the eight-ball in terms of meeting their members' needs and maintaining a reliable system under this transition that we're going through."

Natasha Henderson, SPP's director of system planning, said the grid operator has been doing economic planning for "some time," resulting in small portfolios. She agreed the RTO must use accurate study inputs and said some of the more aggressive forecasts she's seen for electrification triples the load.

"That makes my heart stop," she said. "I stopped breathing for a little bit when I think about where we are and where we might be. I can't necessarily say that, 'Yeah, we're going to triple the load by X time,' but we really need to think about how we can proactively plan going forward."

Natalie McIntire, NRDC | © *RTO Insider LLC*

As is, the assessment says wind growth continues to outpace ITP projections. The 2023 ITP's emerging technologies case projects 46.1 GW of in-service wind in 10 years, a nearly 25% increase from the 10-year assessment just two years ago. SPP had 37.1 GW of in-service wind resources when 2023 began.

MOPC also endorsed:

- The TWG's recommendation to modify the shortfall process for both the 2024 ITP and the 2025 ITP for Year 10 summer. SPP developed the process to address the potential for a network customer's load to exceed their available designated network resources, The changes include using expected conventional resource additions from the generator interconnection queue, ensuring the replacement process is considered for current planned retirements and increasing firm service renewable amounts based on alternative historical time periods.
- The PCWG's proposal for a $12.3 million (47%) baseline increase for an American Electric Power-Oklahoma Gas & Electric 345-kV project in Oklahoma. The project's costs escalated because a substation will need to be built nearly two miles farther than originally sited. "There's not a lot of flat area in a canyon location," OG&E's Mark Barbee explained.

Update Delays Reduced

AEP's Brian Johnson, the PCWG's chair, said stakeholders, staff and the MMU have spent much of this year addressing transmission

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upgrade delays that have frustrated some renewable energy developers.

A revision request (*RR574*) is wending its way through the stakeholder process. It refines the task of identifying project in-service dates when a notification to construct is accepted and establishes routine project updates to stakeholders and governance groups and advanced notification of delays.

"Transparency and situational awareness ... we're looking for increased accuracy from [transmission operators] in that quarterly update," Johnson said, noting project costs often have been the focus instead of service dates.

EDP Renewables' David Mindham said it was apparent SPP is doing a "really, really good job" of building the construction it commits to and thanked Johnson for the work, but asked SPP be given more authority in the process.

"A lot of us have made very large investment decisions based on those transmission upgrades coming into service ... Those upgrades need to be prioritized and SPP needs to have the authority to help mitigate those issues and, if the TO cannot build it for whatever reason, find a way to reassign that," Mindham said. "I think it's worthy of a discussion in this forum because we need more than just transparency. We need a clear message that these transmission lines are important. They've been approved by the SPP board to benefit SPP consumers and they need to be built."

"When you have a project that is delayed and maybe causing economic issues, there's a cost to that," Johnson responded. "If there are alternatives available, maybe they cost some more money but save you time, those need to be vetted and understood and an informed decision made."

Up to $610M in Annual RTO West Savings

Bruce Rew, senior vice president of operations, said SPP will see between $100 million and $610 million in annual value when its RTO West goes live in April 2026, primarily through the better use of seven DC ties the grid operator would manage between the Eastern and Western Interconnections.

SPP secured RTO West commitments in September from nine utilities, culminating three years of work with western parties. SPP's Board of Directors already has approved 15 terms and conditions for new members. (See, *WAPA, Basin Electric Commit to SPP's RTO West* "Board OKs Western Expansion, GI Queue Plan," *SPP Board of Directors/Members Committee Briefs: July 26-27, 2021*.)

SPP's expansion into the West will result in a single balancing authority with two BA areas under a single tariff, Rew said. The SPP West BAA will operate as a member of the Western Power Pool Reserve Sharing Group. Single-market solutions will be optimized across the DC ties' 510 MW of bi-directional capacity.

Several West-only working groups will be formed to help draft the estimated 15 revision requests that will go into the initial tariff changes that will be filed next year at FERC. Accommodating western differences in planning reserve margins and resource adequacy requirements will necessitate several supplemental filings.

"You will begin seeing a lot of engagement at the working group level," Rew said. "There's definitely a lot of work to do between now and April of 2026."

Alluding to an image of the ceremonial golden spike ceremony marking the first transcontinental railroad's completion in 1869 that Rew included in his presentation, MOPC chair Alan Myers asked, "Do you get to drive the Golden Spike when this comes together?"

Rew demurred, saying that task likely would fall to CEO Barbara Sugg.

JTIQ Costs Up to $1.67 Billion

SPP staff said the cost of its joint targeted interconnection queue (JTIQ) portfolio with MISO has increased from $1.06 billion two years ago to an "updated estimate" of $1.67 billion. That is staff's rough attempt to reflect the total costs submitted in its Department of Energy funding application and adjusting for a replacement project.

"Just a caveat, we've refreshed these costs and benefits numbers, but they shouldn't be necessarily considered final. They're simply estimates of costs and benefits," said Clint Savoy, manager of interregional strategy and engagement.

The JITQ portfolio and its five transmission lines was one of several grid resilience and improvement projects to be awarded DOE funding last week from the Infrastructure Investment and Jobs Act. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

MISO and SPP staff will hold a joint stakeholder meeting on the JTIQ proposal in November and bring a revision request to January's MOPC meeting. Kelley said the RTOs will file three tariff revisions at FERC: one for each grid operator and the third to revise their joint operating agreement.

SPP Membership Now 111

MOPC welcomed SPP's newest two members, non-transmission owning members Pine Gate

SPP's Natasha Henderson (left) and Evergy's Derek Brown present the 2023 ITP to MOPC. | *© RTO Insider LLC*

Renewables and Sierra Club. North Carolina-based Pine Gate was the latest to join the RTO, doing so last Friday.

SPP now has 111 members. They include 22 generation and transmission cooperatives, 20 independent power producers, 16 investor-owned utilities, 13 municipal systems, six state agencies, 13 independent transmission companies, 11 power marketers, four large retailers, three public-interest entities, two alternative power entities and one federal agency.

Annual VRL Analysis Endorsed

The committee's consented agenda endorsed the 2023 annual *violation* relaxation limits analysis; aligning the PCWG's scope with business practice language that adds transmission service projects where the cost is 100% directly assigned to one or more customers as an applicable project it can review; and a more than $16 million decrease (20.2%) for a Basin Electric 230-kV project in North Dakota.

The consent agenda also included 13 RRs that would:

- *RR556*: Clarify market participants registering auxiliary load is consistent with any legal or regulatory requirements applicable to the auxiliary load or the entity serving the load.
- *RR558*: Modify the Integrated Marketplace's protocols and the tariff to allow an adder, not to exceed 10% of verifiable costs or cost expectations, in mitigated offers when those verifiable costs or cost expectations exceed $1,000/MWh.
- *RR564*: Clarify managing the effective limit of flowgates and dispatching during congestion is part of maintaining system reliability.
- *RR570*: Align demand response registration with registration timing requirements.
- *RR571*: Modify the real-time make-whole payment commitment period amount's existing formulation by summing all multi-configuration combined cycle resource (MCR) adjustments across all of the applicable intervals before adding it to the overall make-whole payment amount. Compensation still should be given for these MCR adjustments, even if the make-whole payment is $0.
- *RR572*: Update the planning criteria with a definition for "qualified change" that reflects the new NERC mandatory reliability standard FAC-002 (*Facility Interconnection Studies*).
- *RR575*: Compile the annual update of grandfathered agreements to remove expired or terminated GFAs and update termination dates and changes in buying or selling parties.
- *RR576*: Remove vendor-specific requirements from the ITP manual's fuel prices section to allow more flexibility in choosing data that is used in the ITP assessments.
- *RR579*: Add language to the market protocols to clarify that in the event of a 0- MW effective limit, those constraints will have the highest VRL value ($/MW).
- *RR580*: Improve the SmartQ online portal (*https://smartq.spp.org/*) to handle generation interconnection request submissions and align data requirements to the evolving IC requests.
- *RR581*: Comply with FERC Order 895 by allowing additional credit-related information to be shared among SPP and other commission-authorized market operators beyond existing confidentiality provisions. The information shared would be treated as confidential, as defined within each market operators' tariff.
- *RR585*: Correct current footnote to correctly reflect business practice 7250's (GI Manual) process for both steady state and stability if requests are electrically equivalent.
- *RR586*: Provide examples of what is and what is not considered a non-transmission solution technology in SPP's effort to expand "transmission" as improving the use of existing assets and modify planning processes to allow use of non-transmission expansion solutions. ■

— Tom Kleckner

Company Briefs

Navigator Cancels CO2 Pipeline

Navigator CO2

Navigator CO_2 last week announced it is nixing plans for a 1,300-mile pipeline to take carbon dioxide from ethanol plants across five states to be sequestered in Illinois.

"The development of Navigator CO_2's pipeline project has been challenging. Given the unpredictable nature of the regulatory and government processes involved, particularly in South Dakota and Iowa, the company has decided to cancel its pipeline project," Navigator said in a statement.

More: *Energy News Network*

Another Delay, Cost Increase for Mountain Valley Pipeline

Equitrans Midstream Corp. last week pushed back the service date of the Mountain Valley Pipeline from the end of this year to the beginning of 2024.

The expected cost of the pipeline also increased from $6.6 billion to $7.2 billion. The disclosures were made in a filing with the Securities and Exchange Commission.

"Certain unforeseen factors have substantially affected the pace of construction and account for more than half of the increase in estimated project costs," Equitrans said in the filing.

More: *The Roanoke Times*

Summit: Pipeline System Won't be Operational Until 2026

SUMMIT CARBON SOLUTIONS

Summit Carbon Solutions last week pushed back the estimated operational date of its carbon dioxide pipeline system to 2026 following permit setbacks in the Dakotas.

The company initially indicated its five-state, 2,000-mile system would be in operation sometime in 2024 and would transport captured carbon dioxide from ethanol plants for underground sequestration in North Dakota. However, regulators in North and South Dakota rejected Summit's permit requests in recent months. The company's permit process with the Iowa Utilities Board has also been ongoing for more than two years.

More: *Iowa Capital Dispatch*

VC Summer Onsite Manager Sentenced to Home Detention

Carl Churchman, a former Westinghouse executive and onsite project manager of the doomed expansion of the V.C. Summer nuclear plant in South Carolina, was sentenced to one year of probation, including six months of home detention, for lying to federal investigators.

Churchman pleaded guilty back in June 2021 as part of a plea deal, agreeing to cooperate with federal investigators and testify before grand juries.

During an interview with an FBI agent in May 2019, Churchman was asked a series of questions about the completion dates for the two reactors. He claimed he did not know the dates before they were reported and did not know who made the decision to report the dates to the owners. Investigators later obtained emails and documents related to the project that showed Churchman had received and discussed the dates in early 2017.

More: *The Post and Courier*

GM Delays Orion Transition for EV Truck Production by a Year

GM

General Motors last week announced it is pushing back the launch of electric trucks at its Orion Assembly plant by one year to late 2025, meaning the Michigan factory will be idled for up to two years.

GM said it is pushing back one year "to better manage capital investment while aligning with evolving EV demand. In addition, we have identified engineering improvements that we will implement to increase the profitability of our products."

More: *The Detroit News*

Federal Briefs

FERC OKs Natural Gas Pipeline Expansion in Pacific Northwest

FERC last week approved the expansion of a natural gas pipeline in the Pacific Northwest despite protests from environmental groups and top officials in West Coast states.

The project, known as GTN Xpress, aims to expand the capacity of the Gas Transmission Northwest pipeline that runs through Idaho, Washington and Oregon.

TC Energy, the owner of the pipeline, plans to modify three compressor stations along the route.

More: *The Associated Press*

IEA: Grid Must Double in Size by 2040 to Hit Climate Goals

Fatih Birol, the executive director of the International Energy Agency (IEA), last week said that the equivalent of the entire global electricity grid must be added or refurbished by 2040 to hit climate targets and ensure reliable power supplies.

Furthermore, global investment in grids needs to double to more than $600 billion a year by 2030 to hit national climate targets after "over a decade of stagnation at the global level," the IEA said.

The IEA also warned that delays in grid investment and reforms would increase reliance on gas, pushing up carbon emissions and putting a goal of limiting global heating to 1.5C above pre-industrial levels "out of reach." It said that the world's electricity use needed to grow 20% faster in the next decade than it did in the previous one to hit stated goals.

More: *The Guardian*

Labor Department Finds Health, Safety Violations at GM Battery Plant

The Labor Department last week said investigators found 19 safety and health violations at a General Motors joint venture EV battery plant in Ohio during a two-week period this year.

The Labor Department said inspectors found that Ultium Cells didn't comply with federal safety standards for use of personal protective equipment. They also found that the company didn't install guards on machines or train workers in procedures to control hazardous energy, and it failed to provide eye wash stations, emergency showers and hand protection, among other violations.

The department's Occupational Safety and Health Administration has proposed fining Ultium Cells $270,091 for the alleged violations. Ultium Cells has 15 business days from the date it received the citations to comply, request an informal conference or contest the findings with an independent commission.

More: *The Associated Press*

EIA: US is World's Biggest LNG Exporter

The U.S. exported more liquefied natural gas than any other country in the world in the first half of 2023, according to the Energy Information Administration.

The U.S. exported an average of 11.6 billion cubic feet per day, while Australia and Qatar exported 10.6 and 10.4 billion cubic feet, respectively.

Two-thirds of the LNG exports went to European Union countries and the U.K., in large part to compensate for the lack of Russian gas as the war in Ukraine grinds on.

More: *Canary Media*

State Briefs

CALIFORNIA

Trucking Assoc. Sues State ARB Over Zero-Emissions Goal

The state trucking association last week sued the Air Resources Board over a new regulation affecting big rigs, claiming the state cannot begin regulating trucking emissions without getting permission from EPA.

The state's "advanced clean fleets" regulation aims to make sure all new trucks sold after 2045 are zero-emission vehicles. The trucking association wants the regulations to be declared invalid and contrary to law. It is also asking for an injunction to stop the board from enforcing the regulations.

More: *KCRA*

COLORADO

AQCC Mandate: 82% of Car Sales Must be EVs by 2032

The Air Quality Control Commission last week passed a mandate requiring EVs make up 82% of car dealer lots by 2032.

Colorado has an existing clean cars mandate that expires in 2025 with dealer inventory in EVs set at 25%.

The Environmental Defense Fund said Colorado is the ninth state to adopt the second phase of California's clean car rules, and the first in the Mountain West.

More: *The Colorado Sun*

FLORIDA

Duke Energy Asks PSC to Pass Along Hurricane Idalia Costs to Customers

Duke Energy last week filed a proposal with the Public Service Commission seeking to pass along $91.9 million in costs from Hurricane Idalia to customers in 2024.

If the overall proposal is approved, Duke would collect $166.1 million in storm-related costs from customers in 2024.

Duke in April began recovering what is expected to be $431.4 million for costs from hurricanes Ian, Nicole, Elsa, Eta and Isaias and Tropical Storm Fred. Those costs were slated to be recovered over a yearlong period through March 2024. As part of last week's proposal, the remaining costs from those storms would be spread throughout 2024, rather than collected only during the first three months.

More: *Tampa Bay Times*

ILLINOIS

Piatt County Approves County's First Wind Farm

The Piatt County Board voted 4-2 last week to approve a special use permit for the county's first wind farm despite several members making it clear they were approving the project reluctantly.

A new state law sets guidelines for wind and solar farms and Board member Michael Beem said as long as the Prosperity Wind project meets those guidelines, the county cannot refuse it.

Construction is expected to last throughout 2024, with potential operations beginning as early as November or December of next year.

More: *IPM News*

INDIANA

Marshall County Passes 1-Year Moratorium on Utility-Scale Batteries

Marshall County Commissioners last week passed an ordinance to enact a 12-month moratorium on utility-scale battery energy storage systems.

The moratorium was enacted to allow the county time to create standards and regulations in the Zoning Ordinance for the proposed storage system and any others that may consider the county in the future.

More: *WTCA*

URC Approves I&M's Request to Build 4 Solar Plants

The Utility Regulatory Commission last week approved Indiana Michigan Power's plan to build four solar farms totaling 749 MW.

The company said it will invest about

$1 billion in the two largest plants, Lake Trout and Mayapple, which I&M will own and operate. I&M will then purchase the power generated from the Sculpin and Elkhart County plants, which will be independently operated.

The Elkhart County and Sculpin plants are expected to be operational by the end of 2025, with the other two set to be completed by spring 2026.

More: *WPTA*

IOWA

Iowa City Begins Charging Users for EV Charging Stations

Iowa City last week began charging a 16 cents per kWh for people charging their EVs at public charging stations.

The fee is result of a new state tax that was recently added to EV charging in non-residential locations. The purpose behind the state tax is to recoup some revenue lost from diesel and gasoline taxes as more people switch to EVs. The new tax is 0.026 cents per kWh and it took effect on July 1.

The city has 12 charging stations with two additional stations being added next year.

More: *The Daily Iowan*

MICHIGAN

House Panel Passes Renewable Permitting Package

The House Energy, Communications and Technology Committee last week voted 9-7 to refer a package of bills that would move permitting of large-scale solar energy developments to the Public Service Commission.

Under the bills, the PSC would be the main avenue for permitting large-scale renewable projects, although developers could still pursue approval from a local planning authority.

The bills will move to the House floor for consideration.

More: *Michigan Advance*

NEW MEXICO

Lujan Grisham: State Agencies Must Switch to All-EV Fleet by 2035

Gov. **Michelle Lujan Grisham** (D) last week signed an executive order directing state agencies to switch to an all-electric vehicle fleet within the next 12 years.

The order directs departments to purchase zero-emission vehicles for all new acquisitions where one or more options are available. Exceptions to the order include law enforcement vehicles, firefighting trucks and some other heavy-duty vehicles.

More: *The Associated Press*

OHIO

Solar, Wind Farms Banned Entirely in Columbiana County

All 18 townships in Columbiana County have effectively banned large solar and wind farms.

County commissioners last week approved bans for the last three townships not already covered, which means large energy arrays generating more than 50 MW are prohibited in the county.

One project that began before the bans went into effect is still going forward, however commissioners took action to reserve their right to file questions or objections on it with Power Siting Board.

More: *WKBN*

Supreme Court OKs Construction of 2 Solar Farms in Preble County

The Ohio Supreme Court last week approved the construction of two large solar farms in Preble County.

The court found the Power Siting Board in June 2021 properly authorized the certificates to build Alamo Solar I and Angelina Solar I. Concerned Citizens of Preble County had appealed the board's approval.

Each solar farm will have a capacity of about 50 MW.

More: *Dayton Daily News*

PUC Says RPA Energy Cannot Do Business in State

The Public Utilities Commission last week ruled that New York-based RPA Energy, also known as Green Choice Energy, can no longer do business in the state and faces a $1.44 million fine for 159 violations.

A PUC investigation said RPA Energy forged customer signatures and altered recorded sales calls.

Green Energy President and CEO Brian Trombino said the company plans to appeal to PUCO and, if necessary, the Ohio Supreme Court.

More: *The Center Square*

WEST VIRGINIA

AG Asks Supreme Court for Emergency Stay of 'Good Neighbor Plan'

Attorney General Patrick Morrisey (R) last week asked the U.S. Supreme Court of Appeals to issue an emergency stay of the Biden administration's "Good Neighbor Plan."

West Virginia was joined by the states of Ohio and Indiana in seeking the emergency high court intervention. The rule, if allowed to take effect, would empower EPA to regulate downward emissions from the individual states. Earlier this year, Morrisey secured a temporary stay from the Fourth Circuit of EPA's disapproval of the state's related implementation plan.

More: *Bluefield Daily Telegraph*

WYOMING

State Sues EPA For Not Acting on Coal Ash Plan

Wyoming last week sued EPA for not acting on its coal ask plan within 180 days of its submission.

The Wyoming Solid Waste Disposal Act requires EPA to approve, in whole or in part, a state's permitting plan for disposing of coal ash within 180 days of the state submitting that plan. The state's Department of Environmental Quality sent EPA its coal-ash disposal permitting plan on Feb. 6. That would have given EPA until Aug. 5 to decide.

Other than acknowledging that Wyoming sent the plan, EPA did nothing, the petition alleges. On Aug. 10, five days after EPA's deadline passed, Wyoming warned EPA it was bracing to sue the agency after 60 days more.

More: *Cowboy State Daily*