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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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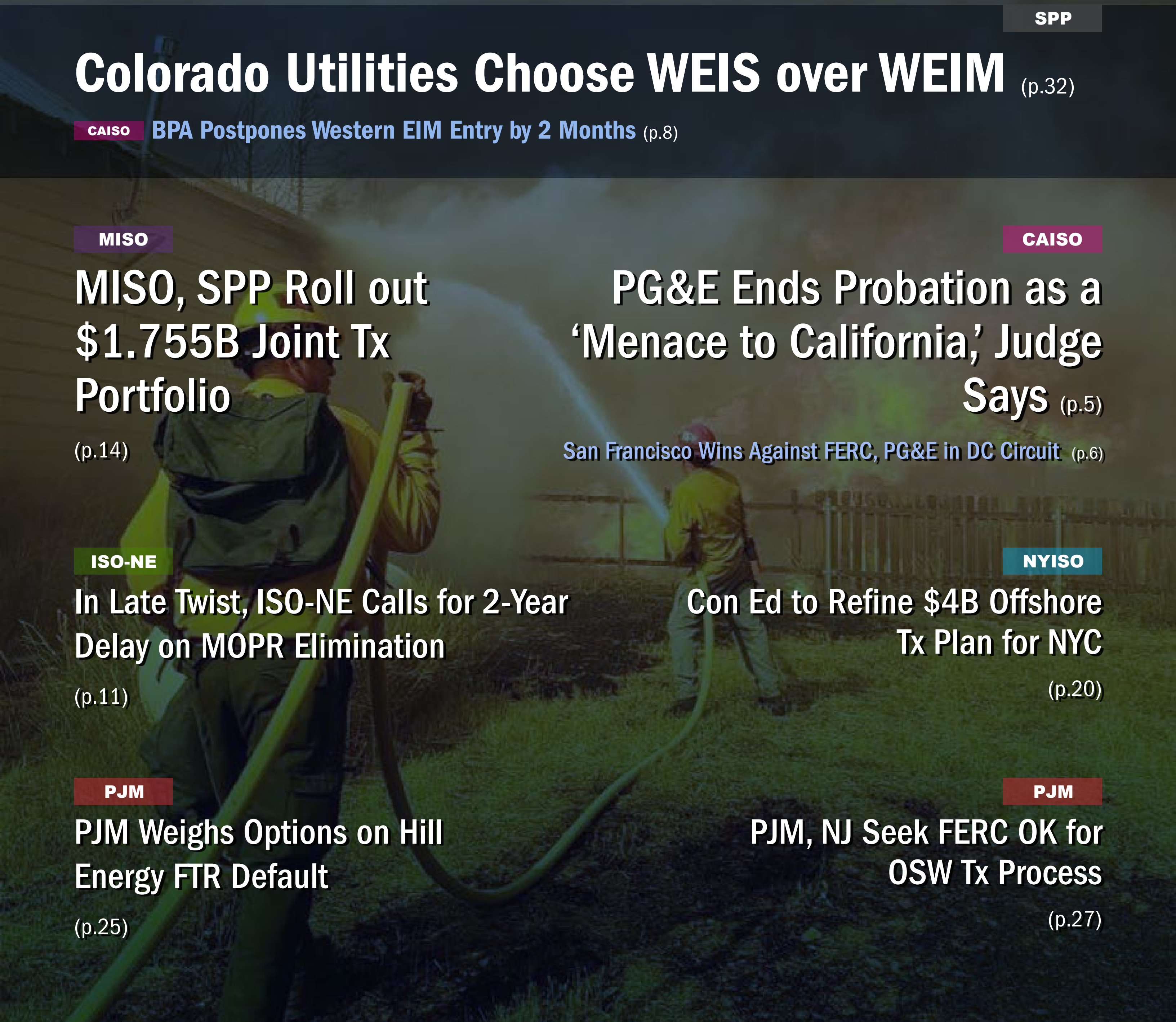

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In this week's issue

Correction

A Jan. 24 article, *FERC Denies Co-ops' $79M Complaint vs. SPP*, incorrectly said two cooperatives alleging SPP "misapplied" tariff provisions requested that the "grid operator be assessed $2.2 million in reliability unit commitment penalties." The sentence should have read, "The cooperatives also requested the grid operator assess them $2.2 million in reliability unit commitment penalties."

FERC/Federal News

Robo Stepping down as NextEra's CEO

Company's Share Price down 8% on the News

By Tom Kleckner

Jim Robo is stepping down after 10 years as NextEra's CEO. | *© RTO Insider LLC*

Jim Robo on Jan. 25 said he is stepping down after almost 10 years as CEO of NextEra Energy, concluding what he characterized a "long-term succession process" he has undertaken with the board of directors during the last six years.

"It has been an honor and a privilege to serve as CEO. I'm as excited as I've ever been about the future prospects of NextEra Energy and NextEra Energy Partners," Robo, 59, said during NextEra's quarterly earnings conference call with financial analysts.

Saying part of a CEO's legacy is the "new leader in the next-generation leadership team that follows," Robo introduced as his successor John Ketchum, a 19-year NextEra veteran, CEO of NextEra Energy Resources (NEER) and president of NextEra Energy Partners.

Ketchum said he intends to remain "intensely focused" on delivering and building upon NextEra's "long track record of success."

"I believe there is no company better positioned to lead our country's energy transformation than NextEra Energy," he told analysts.

Under Robo's guidance, NextEra has become the world's largest generator of renewables, operating more than 17 GW of wind and solar energy. With a market cap of over $147 billion, it is bigger than any other utility in the world. However, efforts to acquire other utilities, including Hawaii Electric and Texas' Oncor, fell short before it acquired Gulf Power from Southern Co. in 2018.

Robo joined NextEra in 2002, becoming CEO in July 2012. Since then, the company's share price has gone from $17.08 to more than $300 in 2020, surpassing even ExxonMobil before a four-for-one stock split that October.

The company's share price plunged on the news, dropping 4.5% from $81.87 when the market opened. Shares closed at $75.10, down $6.77 (8.3%).

Robo will serve as NextEra's executive chairman during a brief transition period expected to end in April.

The Florida-based company *announced* several other leadership changes, effective March 1:

John Ketchum | *NextEra Energy*

- Eric Silagy, president and CEO of NextEra subsidiary Florida Power & Light, will become the utility's chairman.
- CFO Rebecca Kujawa was named president and CEO of NEER, succeeding Ketchum.
- Kirk Crews, NEER's vice president of business management, was named NextEra's CFO, replacing Kujawa.

NextEra also *reported* its fourth-quarter and year-end earnings Jan. 25. It said quarterly earnings were $1.2 billion ($0.61/share), compared to 2020's fourth-quarter loss of $5 million. Analysts polled by FactSet had expected adjusted earnings of 39 cents/share; they came in at 41 cents.

For the year, earnings came in at $3.6 billion ($1.81/share), compared to $2.9 billion ($1.48/share) in 2020. ■

NextEra Energy's corporate headquarters in Juno Beach, Fla. | *© RTO Insider LLC*

FERC/Federal News

Electric, Gas Revenues Drive Xcel's 2021 Earnings

Xcel Energy said Thursday higher electric and natural gas revenues aided the company in meeting its earnings guidance for the 17th straight year.

Xcel *reported* year-end earnings of $1.6 billion ($2.96/share), up from 2020's performance of $1.47 billion ($2.79/share). For the quarter, earnings were $315 million ($0.58/share), compared to $288 million ($0.54/share) in last year's fourth quarter.

"We had a solid year delivering earnings … and achieving our earnings guidance for the 17th consecutive year. We are well positioned for the future," CEO Bob Frenzel said in a statement.

Analysts had expected fourth-quarter earnings of 56 to 57 cents/share.

Earnings were partially offset by increases in electric fuel and purchased power, costs of natural gas sold and transported, additional depreciation and lower allowance for funds used during construction.

Xcel Energy's Sagamore Wind Project in New Mexico | *Xcel Energy*

The Minneapolis-based company reaffirmed its 2022 earnings forecast of $3.10 to $3.20/share.

Xcel is banking on clean energy to meet its guidance. It has filed resource plans in Minnesota and Colorado that it says will accelerate its exit from coal-fired generation in those states by 2030 and 2034, respectively. The company last year said it had reduced carbon emissions by 50% from 2005 levels and is on track to reach an 80% reduction by 2030.

Xcel's share price closed up Thursday at $68.94, a $1.32 increase from the previous close. ■

— Tom Kleckner

National/Federal news from our other channels

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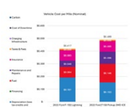

Report: EVs at Price Parity with ICE Vehicles in 2022 — NetZero Insider

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CAISO/West News

PG&E Ends Probation as a 'Menace to California,' Judge Says

By Hudson Sangree

Pacific Gas and Electric ended five years of probation Jan. 25 with the judge in charge lamenting that California's largest utility had caused more damage on probation than it had before it was sentenced.

PG&E was placed on probation in January 2017 after being convicted of six felonies related to the San Bruno gas explosion, which killed eight people and destroyed a suburban San Francisco neighborhood in September 2010.

"While on probation, PG&E has set at least 31 wildfires, burned nearly 1.5 million acres, burned 23,956 structures and killed 113 Californians," Judge William Alsup, of the U.S. District Court for Northern California, *wrote* in his parting comments on the case.

The utility pleaded guilty to 84 manslaughter charges in the 2018 Camp Fire, which leveled the town of Paradise, Alsup said. It faces five felony counts in the 2019 Kincade Fire in Sonoma County and four manslaughter charges from the 2020 Zogg Fire in Shasta County. The Dixie Fire, ignited by PG&E equipment last summer, was the second largest in state history at nearly 1 million acres and will likely result in lawsuits and possibly criminal charges, he said.

"So, in these five years, PG&E has gone on a crime spree and will emerge from probation as a continuing menace to California," Alsup said.

"Rehabilitation of a criminal offender remains the paramount goal of probation," he said. "During these five years of criminal probation, we have tried hard to rehabilitate PG&E. As the supervising district judge, however, I must acknowledge failure."

Alsup told federal prosecutors on Jan. 3 that he would give "serious consideration" to a request for more probation time based on the state criminal charges against PG&E, but the U.S. Attorney's Office decided not to seek an extension. (See *Judge Refrains from Adding Time to PG&E Probation*.)

PG&E Responds

In a November court *filing*, PG&E assessed its own progress on probation, often in contrast to the judge's remarks.

"PG&E acknowledges, deeply regrets and owns the tragic consequences of the wildfires caused by its equipment," it said. "The company has taken a stand that catastrophic wildfires shall stop." But during the past four years, thanks in part to the court's supervision, its "electric grid is fundamentally safer."

"PG&E believes it is on the right path," it said. With its 70,000-square-mile service territory and the speed at which climate change appears to be impacting Northern California, there are "no fast or fail-proof options," but the utility insisted it has changed.

PG&E is now "led by a board and senior management team that is new compared to those in place at the time of the San Bruno tragedy, the North Bay fires [in October 2017] and the Camp Fire," it said. "Recognizing the need for the best thinking on operations, safety and risk, the company has hired leaders from stable, safe and operationally excellent utilities around the country," including new CEO Patti Poppe, former head of CMS Energy in Michigan.

PG&E cited its use of public safety power shutoffs to prevent ignitions, which it did not use in 2017 but now employs widely in fire season along with fast-trip sensors to shut down power lines when faults occur.

The utility contended it has greatly improved its vegetation management. Trees and limbs falling on power lines have caused many of the major fires in the past five years.

"Between 2017 and 2021, PG&E increased spending on vegetation management from approximately $440 million a year to approximately $1.4 billion, representing an over 200% increase," it said. "The total number of employees and contractors dedicated to vegetation management rose from 4,446 in 2019 to 10,265 in 2021.

"These unprecedented monetary and workforce investments have resulted in a significant amount of additional work," it said. "In 2021, PG&E has removed or trimmed over 1.63 million trees as of Oct. 31 and forecasts it will remove or trim 1.82 million trees in total by year-end, a 20% increase over the 1.52 million trees worked in 2019."

Alsup, however, said tree trimming remains one of the utility's biggest problems.

"We remain trapped in a tragic era of PG&E wildfires because for decades it neglected its duties concerning hazard-tree removal and vegetation clearance, even though such duties were required by California's Public Resource Code," Alsup said. "In time, this neglect led to hazard trees and limbs falling on its distribution lines and sparking wildfires or becoming 'ground faults,' wherein the tree remains against a live wire and conducts sufficient electrical power to the earth to overheat and explode in flames.

Firefighters try to protect a home in Greenville, Calif., a community destroyed by the Dixie Fire in August. | *National Forest Service*

"PG&E's backlog of unattended trees and vegetation was staggering at the outset of probation," he said. "As probation ends, PG&E remains at least seven years, [in] my estimate, from coming close to being current. During its criminal probation, all or virtually all of the wildfires started by PG&E distribution lines have involved hazard trees."

The Camp and Kincade fires were started by broken transmission lines that ignited dry vegetation, he noted.

Alsup said he believes a "systemic cause" of distribution-line fires has been PG&E's outsourcing of tree trimming and line inspections.

"A large part of the wildfire problem, as the [court-appointed] monitor has pointed out, has been sloppy inspection and clearance work, almost exclusively outsourced to independent contractors," he said. PG&E should hire and train "as many arborists as are needed to fully comply with California's Public Resource Code," and the state should outlaw or restrict outsourcing.

The utility's size is another problem, Alsup continued. PG&E operates 107,000 circuit miles of distribution lines and 18,500 miles of transmission lines, with about half its territory in high fire-threat districts.

Alsup said he has "come to fear" that PG&E should be split into at least two entities, one to serve fire-prone areas and one or more to serve the rest of its 5.5 million electric customers.

"Less sprawling utilities would be easier to train and to instill practices and procedures that truly put safety first." ■

CAISO/West News

San Francisco Wins Against FERC, PG&E in DC Circuit

Cases Involved PG&E's Distribution System in City

By Hudson Sangree

The D.C. Circuit Court of Appeals overturned FERC on Jan. 25 in two cases brought by the city and county of San Francisco against Pacific Gas and Electric for failing to deliver electricity to customers in violation of its wholesale distribution tariff (*20-1084*).

In one case, the city contested PG&E's refusal to provide lower-voltage secondary service to many sites within the city. San Francisco filed a complaint with FERC in January 2019 alleging PG&E had consistently refused to make new interconnections at secondary voltage unless the total electricity demand was less than 75 kW.

PG&E instead offered to connect higher-voltage primary service, which requires the installation of transformers and carries higher fixed costs for ratepayers, San Francisco said. The city argued that the practice violated PG&E's tariff because it requires the utility to offer secondary service when requested and to expand its infrastructure where necessary.

The company argued that it did not categorically deny secondary service in cases where demand exceeded 75 kW and said its denials in some cases were based on technical, safety and reliability concerns.

FERC denied San Francisco's complaint, ruling that PG&E should decide what level of service is appropriate for customers.

"While the [wholesale distribution tariff] does not preclude a … customer from requesting the level of service that it wishes to take, PG&E, as the wholesale distribution service provider, is ultimately responsible for the safety and reliability of its distribution system," FERC wrote in its April 2020 order (*EL19-38*). "Accordingly, we find that it is appropriate for PG&E, as that provider, to have discretion to determine what level of service is both appropriate and available based upon the status and configuration of its existing wholesale distribution system facilities and the nature and location of the interconnection request."

| Shutterstock

The initial decision, as well as its order on rehearing that upheld it later in September, were unanimous among the commissioners at the time, which included current Chair Richard Glick (D) and Commissioner James Danly (R).

But in an opinion written by D.C. Circuit Judge Judith Rogers, a three-judge panel found that FERC failed to scrutinize the safety and reliability risks cited by PG&E. The judges also rejected PG&E's contention that it decides appropriate voltages case by case.

"Evidence before the commission showed that since 2015, many of San Francisco's new interconnection requests exceeding 75 kW have been denied secondary service by PG&E, and that the proportion of new interconnections above 75 kW receiving primary service has increased since 2015," the court said. It cited a July 2019 letter written by PG&E to San Francisco saying it was no longer "willing to make additional accommodations" for secondary service.

"The July 1, 2019, letter hardly indicates that PG&E intends to evaluate San Francisco's applications on a case-by-case basis," the court wrote.

On rehearing FERC had said the "75-kW threshold is merely a 'guidepost,' while reaffirming its position that PG&E makes case-by-case determinations of which voltage to provide," the court noted.

"Even if the 75-kW threshold is a guidepost, however, that kind of numerical threshold is the type of requirement that the 'rule of reason' requires be stated in the tariff," the court said.

"Because the commission did not adequately explain any operational or engineering rationale justifying PG&E's 75-kW 'guidepost' and did not explain why that guidepost did not need to be in the filed tariff, the court vacates the voltage orders and remands the case to the commission for further proceedings consistent with this opinion," it said.

Grandfathering Service

In the second case, which was consolidated with the first, San Francisco argued that PG&E had denied service to delivery points that were eligible for it under a tariff grandfathering provision.

In interpreting the provision, PG&E cited the tariff's reference to Federal Power Act Section 212(h), which prohibits mandatory retail wheeling with certain exceptions.

"No order issued under this chapter shall be conditioned upon or require the transmission of electric energy directly to an ultimate consumer … unless such entity was providing electric service to such ultimate consumer on Oct. 24, 1992," the FPA says.

PG&E said that meant it had to serve end users it served in 1992 but not those that had moved. San Francisco argued the tariff requires PG&E to serve even those customers that had relocated since 1992.

A FERC administrative law judge interpreted the FPA, given prior FERC orders, as supporting San Francisco's argument "that grandfathering applies to the class of customers that was eligible to receive wholesale distribution service on Oct. 24, 1992, regardless of where in the city those customers may be located now or in the future."

FERC reversed the ALJ's decision, agreeing with PG&E's interpretation of the tariff's grandfathering provision.

The court, however, said FERC's interpretation of the tariff was too narrow and its "attempts to defend its interpretation [were] unpersuasive."

"That the tariff references 'points of delivery' does not necessarily imply that only specific points of delivery may be grandfathered, and those references to 'points of delivery' do not change the fact that the tariff expressly references the criteria of Section 212(h)(2)," it said.

The court criticized FERC's orders in the case as demonstrating a "troubling pattern of inattentiveness to potential anticompetitive effects of PG&E's administration of its open-access tariff." Faced with claims that PG&E was refusing service to San Francisco customers, FERC "fell short of meeting its duty to ensure that rules or practices affecting wholesale rates are just and reasonable," it said. ■

CAISO/West News

Dueling Bills Seek Opposing Fates for Wash. Siting Council

By John Stang

Two Washington bills seek opposite outcomes for the state's Energy Facility Site Evaluation Council (EFSEC).

The council, comprising representatives from several state agencies, makes recommendations to the governor for final decisions on the placement of solar farms, wind turbines and other energy resources.

If a wind or solar developer opts to seek state approval instead of obtaining county permits, it can bypass county governments by going through EFSEC. Or a developer can choose to have the appropriate county government handle the permitting, sidestepping EFSEC.

Rep. Mark Klicker (R) has introduced one bill (*HB 1871*) to stop EFSEC from reviewing solar and wind projects until late 2023 after a task force studies the issue.

Klicker represents much of Benton County, where heavy opposition has surfaced to the Horse Heaven Hills wind turbine proposal — mostly because many residents of Washington's Tri-Cities area don't want to see windmills on their southern horizon. (See *Wind Project Sows Controversy in Horse Heaven*.) That bill showed up at a Jan. 25 public hearing before the House Environment and Energy Committee.

The committee that day also heard testimony that mostly supported a bill (*HB 1812*) by Rep. Joe Fitzgibbon (D) that would bolster the authority of EFSEC while also boosting tribal participation in reviews when needed. Fitzgibbon is the committee's chairman, meaning his bill has the better chance of moving beyond the committee.

On Knicker's bill, testimony stressed that Eastern Washington residents believe that wind and solar farms chip away at their tax bases and that their region is being unfairly targeted to provide most of the state's alternative energy sources. Critics of EFSEC argue the council is not receptive to local concerns. Habitat concerns did not pop up in the hearing.

"You guys are in too big of a hurry to meet climate change goals," said Klickitat County Commissioner Dan Christopher. Josh Weiss, a lobbyist for Benton County said, "Local planning is capable of dealing with these projects."

"It does things to the people of rural Washington instead of doing things for them," said Dave Barta, representing the Farm Bureau for Klickitat and Yakima counties.

However, EFSEC Chair Kathleen Drew said the council has approved only three wind and solar projects so far with only a handful still under review. "The vast majority of wind and solar [projects] have gone before the county governments. I believe [EFSEC's] siting process is the most thorough environmental review."

Testimony on Fitzgibbon's bill was overwhelmingly in favor of the legislation. There was very little overlap between the people testifying on the two bills. The bulk of the support came from labor and environmental organizations.

"We're for any effort to bring speed and certainty to the process," Matt Steuerwalt of NextEra Energy Resources said. Kelly Hall of Climate Solutions said, "We need to consolidate bringing new jobs to the state."

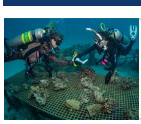
The bill would take EFSEC out of the umbrella of the Washington Utilities and Transportation Commission and provide it with its own separate budget. It would also add pipelines to its jurisdiction, streamline some procedures and bolster tribal participation in matters affecting the Native American tribes.

Opposition to EFSEC has arisen in part because of the controversial proposed development of large-scale wind farms in Washington's Horse Heaven Hills area. | *Wines of Washington State*

The hearing also produced the only mention of concerns about solar and wind projects encroaching on sensitive wildlife habitat. The Washington Department of Fish and Wildlife said routing the process through EFSEC would provide stronger protections for habitat.

The Tulalip, Yakama and Puyallup nations warned against streamlining the review process too much, not wanting the state to rubber-stamp proposals. ■

West news from our other channels



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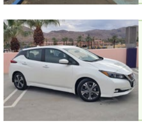

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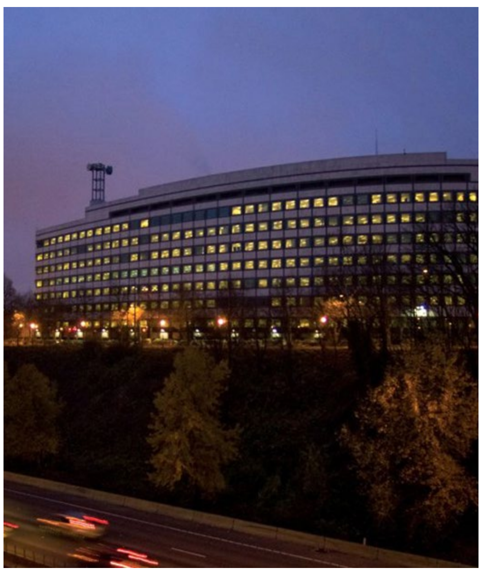
CAISO/West News

BPA Postpones Western EIM Entry by 2 Months

By Robert Mullin

The Bonneville Power Administration will delay its entry into the Western Energy Imbalance Market (WEIM) by two months to work out technical and training issues, the federal power marketing agency said Thursday.

BPA was scheduled to begin trading in the WEIM on March 2 but is now pushing its "go-live" date to May 3, citing customer requests for more testing and training on the computer systems being used to integrate the agency's operations into the market.



BPA headquarters in Portland, Ore. | *DOE*

Speaking Thursday during an agency workshop, Chief Business Transformation Officer Nita Zimmerman said the "short delay" provides BPA with additional time "to ensure the most successful go-live outcome" and "to appropriately address some of the remaining functionality needed for some of the systems that we're still bringing online."

Zimmerman cited "continued challenges" with metering data, outage management, market settlement allocation and billing among its customer base of publicly owned utilities. Early participants in the WEIM have cautioned potential members on the complexity of integrating into the CAISO-operated market and the high level of "discipline" needed to prepare for joining. (See *PacifiCorp Offers Lessons for Future EIM Participants*.)

"Building in this additional time does demonstrate the care and rigor that we're taking — along with our vendors — in bringing this initiative along," Zimmerman said.

But Zimmerman and EIM Program Manager Roger Bentz both assured BPA customers that the agency is "pedal to the metal" and "continuing full-throttle" in its efforts to meet the May 3 timeline.

Bentz pointed to the progress BPA has made in implementing WEIM systems and practices over the past two months, including commencing parallel operations with the market on Dec. 1. The parallel production environment provides new participants the ability to practice under real market conditions, allowing them to submit bids and base schedules, collect e-tags and learn how to adapt operations to real-time developments.

BPA has also successfully tested end-to-end transfers with two adjacent WEIM entities and finished testing the software that will allow it to "donate" transmission capacity to WEIM operations.

Additionally, the agency has also fully staffed and trained its EIM entity scheduling coordinator and operations desks, Bentz said.

Bentz said he was unsure what impact BPA's postponement would have on Avista and Tacoma Power, the two other entities slated to join the WEIM on March 2.

"The latest information we have [is] they are likely to stay with their current schedule of March 2," he said.

"The Tacoma Power team is quickly doing an analysis today and should have more details [Friday]," utility spokesperson Rebekah Anderson told *RTO Insider*.

Avista did not respond to an inquiry about the effect of BPA's delay on its WEIM timeline.

If the two utilities stick to their current timelines, BPA will be modeled out of parallel operations early this month and then rejoin in early March, Bentz said. ■

West news from our other channels

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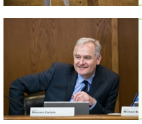

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CAISO/West News

New Tech Needed for 100% Clean Energy, WECC Says

Resources that Act Like Gas-fired Plants Required for Ramping, Inertia

By Hudson Sangree

The West can reach 90% clean energy by 2040 with a combination of renewable resources and batteries, but the last 10% will require new types of flexible resources that can operate like natural gas plants to provide ramping, regulation and inertia on the grid, a study published Friday by WECC found.

"The results of the study indicate that clean energy above 90% will not be achieved economically and efficiently without including additional ECF [emerging clean and flexible] candidate resources," WECC said in its *2040 Clean Energy Sensitivities Study*. "These ECF resources will need to have performance characteristics similar to those of displaced gas-fired generation resources."

The study did not give examples of the kind of resources that might replace gas plants.

"There are many promising clean energy technologies emerging that may provide the same performance characteristics as gas-fired generation resources," it said. "No one can predict what new clean energy technologies may emerge by 2040 or what their performance characteristics will be other than to assert that they will be needed to achieve high levels of clean energy."

The reason for the need, the study said, is that as renewable resources are added to the grid, it will eventually become saturated so that batteries are full, and "excessive" curtailment of wind and solar power takes place around the clock.

"At very high penetrations of variable-energy resources, the number of hours available to dispatch [battery storage systems] diminishes to a point at which curtailments occur at all hours of the day, especially on light load days," it said. "With curtailments occurring at all hours of the day, there are plenty of hours for [batteries] to be charged, but no hours to be dispatched."

"Under these conditions, very little charging of batteries took place after an initial charge, since the energy from an initial charge could not be dispatched, negating the need for future charging," the study said. "As a result, the ability of [batteries] to minimize curtailments is negated."

In the same scenario, "gas-fired generation is being dispatched at all hours of the day in response to congestion and ramping requirements."

"This observation further illustrates the need for resource flexibility from gas-fired resources or some other non-charging resource type with similar performance characteristics as gas-fired generation resources," it said.

A relatively small percentage of gas-like resources "will go a long way to mitigate challenges … [such as] variability, misalignment with load, ramping requirements, and congestion."

The study was the first phase of a two-part project to examine clean energy scenarios through 2040. Phase 2, due later this year, will take a deeper dive into emerging technology and other matters, WECC Senior Staff Engineer Michael Bailey, the report's primary author, said in a *podcast* last week.

WECC made it a priority to analyze potential reliability risks in the Western Interconnection following the events of summer 2020, when CAISO ordered rolling blackouts in a severe heatwave that also strained other areas of the Western grid.

The ERO issued its second *Western Assessment of Resource Adequacy* in December, saying the West faces potential resource shortfalls by 2025 due, in part, to an increase in weather-dependent renewable resources. (See *WECC Warns West Heading for Resource Shortfalls by 2025*.)

The latest study noted that the "current trends toward clean energy are introducing dramatic changes to the [bulk power system] in the West."

"With these changes," it said, "the long-term energy future of the West is becoming less certain and less predictable." ■

In a 90% clean-energy scenario, high curtailments occur (right) unless new emerging clean and flexible (ECF) resources replace gas plants. | *WECC*

ERCOT News

ERCOT, SPP Prep for Latest Wintry Blast

By Tom Kleckner

ERCOT System Operations Vice President Dan Woodfin monitors the Texas grid from his office. | *© RTO Insider LLC*

ERCOT and SPP, the two grid operators that bore the brunt of last February's winter storm, both issued advisories Monday in advance of a cold front that is expected to sweep across the region and bring with it extremely low temperatures and wintry precipitation.

The Texas grid operator published a notice of "extreme cold weather event with potential icing conditions" Wednesday evening through Sunday. SPP meanwhile issued a cold weather advisory for its entire Eastern Interconnection footprint, effective Wednesday through Saturday.

ERCOT's meteorologist *said* temperatures will likely be the winter's lowest, reaching the teens in North Texas and low- to-mid 20s in Central Texas on Friday and Saturday morning. Icy precipitation is expected in West Texas, where most of the state's wind farms are located.

As of Monday afternoon, ERCOT was expecting demand to peak at 72.5 GW on Friday morning, perilously close to the levels that brought the system to its knees nearly a year ago.

The demand projections have bounced around with the weather models. Last Friday's prediction of nearly 73 GW for this Friday had been reduced to 68.7 GW on Monday morning, when models were predicting North Texas temperatures in the teens, rather than single digits.

"Load forecasts are driven by the weather," Dan Woodfin, ERCOT's system operations vice president, told stakeholders Monday. "We'll continue to plan for a little higher [demand] than that."

Woodfin, briefing the Technical Advisory Committee, said staff will continue to maintain conservative operations, setting aside enough operating reserves to cover demand.

Strong winds accompanying the front will increase wind production to about 25 GW, Woodfin said. Vendors responsible for wind forecasts believe that icy conditions will reduce that to 17 GW on Friday.

"At this point, we still look OK for Friday morning," Woodfin said. "We haven't made the decision yet, but we could be asking for more ancillary services."

Concerns over the lack of public outreach were raised again last week when *The Dallas Morning News* *reported* that the grid operator had notified "many stakeholders" Friday morning "indicating that they have begun contacting state agencies and other authorities and are implementing an 'aggressive grid management plan.'"

However, ERCOT has yet to issue a press release or use social media. The Texas Public Utility Commission on Sunday *tweeted* that it was "working closely" with the Texas Division of Emergency Management and other "critical state agencies to keep Texans safe."

ERCOT did not respond to a request for comment on winter advisories, but it has issued the following statement:

"Because of the landmark reforms by the Texas Legislature and implemented by the Public Utility Commission, the grid is more resilient and reliable than it has ever been. ERCOT is confident it will be able to meet electric demand as a result of the rigorous new preparation and resiliency requirements."

Stoic Energy President Doug Lewin, referencing temperatures that are not expected to be as low or as enduring as last February's, said there should be no outages this week.

"If there are, the system's far worse off than anyone thought," he said.

SPP's Advisory its Lowest Level

SPP's is expecting potential icing effects, followed by lower-than-normal temperatures in its region.

The National Weather Service has issued a winter storm watch for central Oklahoma for late today through Thursday. It expects ice and snow will accompany a "significant drop" in temperatures, with highs falling to below freezing Wednesday and Thursday.

An SPP weather advisory is only a step beyond normal operations. They are only issued when staff expect extreme weather in the reliability coordinator service territory, and they do not require conservation measures.

The NWS said the main difference between this winter storm and last February's is that the snowfall is expected to fall continuously and then move out, unlike last year's intermittent precipitation.

The RTO will declare a resource advisory and then conservative operations before entering energy emergency alert levels. ■

ISO-NE News

In Late Twist, ISO-NE Calls for 2-Year Delay on MOPR Elimination

By Sam Mintz

The Mystic Generating Station in Everett, Mass. | *Fletcher6, CC BY-SA 3.0, via Wikimedia Commons*

After months of moving forward with a plan to eliminate the minimum offer price rule (MOPR), ISO-NE is changing course and proposing a two-year transition period that would maintain the rule for the next two capacity auctions.

In a memo ahead of this week's NEPOOL Participants Committee meeting, ISO-NE COO Vamsi Chadalavada wrote that the new plan is based on stakeholder suggestions for a "more gradual" removal of the MOPR that reduces risk.

Under the transition proposal, which Chadalavada said is "clear and predictable," 700 MW of capacity from state-subsidized resources would be able to enter the market through the renewable technology resources (RTR) exemption in FCAs 17 and 18, and the MOPR would be fully replaced by FCA 19.

Specifically, the plan, which closely mirrors *a proposal from Calpine and Vistra*, allows for 300 MW of RTR exemptions in FCA 17 and 400 MW in FCA 18. The exemption is designed to let a limited amount of renewable resources offer into the auction at prices lower than those set by the MOPR.

"The transition proposal will not impede the ability of the sponsored resources under long-term contracts to continue their path towards commercial deployment," Chadalavada said.

The decision could reignite a debate over renewables and reliability, as ISO-NE explicitly states that its intention with the transition is to slow the entry of renewable resources into the capacity market in the interest of energy security.

"The proposed MOPR transition sets a steady pace for new, sponsored technologies to displace existing resources over two auction cycles. More certainty around the quantity of sponsored resources entering the market should attenuate the potential for inefficient retirements and the ensuing reliability risk," Chadalavada wrote. "The two-year, 700-MW transition should help quell a sudden, voluminous and permanent shift that could otherwise occur between entering and exiting resources that may not equivalently contribute to reliability in the commitment period."

The reliability risks, which have been a longtime subject of debate by stakeholders in New England, lie at the intersection of "inefficient" retirements by existing generators and a lack of ability to measure the contributions of new technologies, the memo says.

ISO-NE pointed to conditions in other regions to justify its decision.

"Insufficient dispatchable (natural gas-fired) generation contributed to [California's] inability to serve load during August 2020, and it continues to pose challenging summer operating conditions in that region," Chadalavada wrote. "As the MOPR is eliminated in New England, stakeholders should seek to avoid similar reliability consequences as the region's growing sponsored resources prompt accelerated resource retirements."

The change of plans could lead to a contested vote at the PC meeting this week; the Calpine/Vistra plan was voted down by the Markets Committee in its last meeting. (See *NEPOOL MC Approves ISO-NE Plan to Eliminate MOPR*.)

And it could also put ISO-NE at odds with the FERC majority, which has pushed for removal of the MOPR and last month called again for it to be eliminated "expeditiously." (See *FERC Weighs in as ISO-NE Prepares for Capacity Auction*.) ■

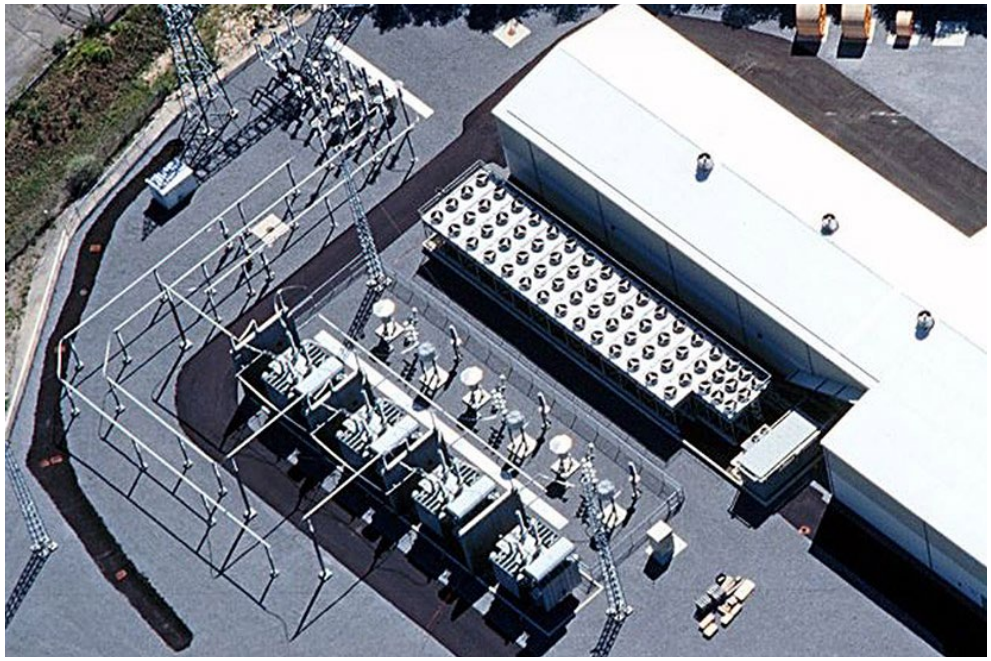
ISO-NE News

DC Circuit Shoots down NE Utilities on CIP Cost Recovery Cutoff Date

By Holden Mann

The D.C. Circuit Court of Appeals on Friday sided with FERC over Cogentrix Energy Power Management and Vistra on a 2020 order that authorized compensation to New England generators and transmission operators for compliance with NERC reliability standards.

FERC's order approved ISO-NE adding a Schedule 17 to its tariff, permitting owners of assets that are critical to the derivation of interconnection reliability operating limits (IROLs) to seek compensation for the costs of complying with NERC's Critical Infrastructure Protection (CIP) standards (*ER20-739*). (See *FERC OKs Payment Rules for IROL Facilities*.) ISO-NE identified 27 generation units at 15 plant locations and one merchant transmission facility that were IROL-critical facilities.

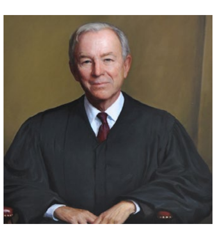


Cross-Sound Cable Co., which operates a 24-mile submarine cable under Long Island Sound to connect the New England and Long Island electric grids, is a merchant transmission facility that ISO-NE has designated as IROL-critical. The 330-MW HVDC line terminates on Long Island at the Shoreham converter station (pictured). | *Cross-Sound Cable Co.*

Under the commission's ruling, facility owners could seek cost recovery as of March 6, 2020; however, FERC ruled that utilities could only recover costs incurred on or after the effective date of their rate filings under Section 205 of the Federal Power Act. A group of utilities, including Cogentrix and Vistra, objected to this cutoff, saying they had already spent "several million dollars" on meeting the CIP requirements and should be allowed to collect all historic costs.

The commission rejected the utilities' rehearing request, clarifying that while "IROL-critical facility owners may seek recovery of the undepreciated costs of … past capital expenditures to comply with the IROL-CIP requirements," it cited its rules against retroactive ratemaking. It also said that the companies had not shown that their inability to recover historic CIP compliance costs in the ISO-NE markets would interfere "with their opportunity to earn a reasonable return in the future." Following the rejection, Cogentrix and Vistra appealed to the D.C. Circuit.

Court Sides with FERC on All Counts



Senior Circuit Judge Arthur Raymond Randolph wrote the opinion. | *D.C. Circuit Court of Appeals*

In its *ruling*, the court agreed with FERC that Schedule 17 "does not address whether costs incurred before the effective date of the critical facility's [Section] 205 filing can be recovered." Writing for the court, Senior Circuit Judge A. Raymond Randolph pointed out that Schedule 17 expressly limits recovery for a particular facility only to costs found in the Section 205 filing for that facility; while this does not forbid recovery of prior costs, it does not permit such recovery as the plaintiffs claimed.

Cogentrix and Vistra also argued that FPA Section 219 requires the commission to "allow recovery of … all prudently incurred costs" of complying with NERC standards, with no reference to the time those costs were sustained. FERC responded that Section 219 cost recovery must be consistent with Section 205, including its "prohibition against retroactive rate recovery."

The utilities countered that the rule against retroactive ratemaking is not explicitly stated in Section 205, but the court shot this argument down as well, pointing out that the Supreme Court has "recognized repeatedly that the filed-rate doctrine and the rule against retroactive ratemaking play an important role in helping the commission fulfill its statutory responsibility."

"The commission could not ensure that rates are just and reasonable if the rates are not on file with the commission for a period of time before the rates go into effect," Randolph wrote. "FPA [Section] 219 … therefore incorporates the filed-rate doctrine and the rule against retroactive ratemaking."

Cogentrix and Vistra's final argument claimed that FERC could not apply its rule against retroactive ratemaking "because there was no rate on file for medium-impact [cyber asset] reliability costs prior to Schedule 17." The court responded that cost recovery for prior CIP compliance investments amounted to changing their rates "for a service that has already been rendered" and therefore was a retroactive action.

While FERC typically uses "historical costs to set current rates," the court said that the utilities were not seeking to estimate future costs based on historical ones. Instead, they were looking to use new rates to recover costs "going back to 2014." This is forbidden by the FPA because it amounts to utilities charging more to make up for previous under-collection, it said.

"Cogentrix and Vistra received transmission rates under the ISO New England tariff during the relevant period," the court said. "That the companies failed to recover mandatory reliability costs does not allow an exception to the rule against retroactive ratemaking." ■

ISO-NE News

FERC Denies NTE's Last-ditch Effort on Killingly

FERC on Friday turned down NTE Energy's last-ditch attempt to hang on to its capacity supply obligation for the Killingly Energy Center, which was terminated by ISO-NE in November (*ER22-355-001*).

The commission had accepted that ruling by the RTO earlier in January, agreeing that the development of the Connecticut plant is not on track to meet critical milestones by 2024 and fulfill its obligations under the CSO obtained in Forward Capacity Auction 13. (See *FERC Accepts ISO-NE Request to Terminate Killingly CSO*.)

NTE's latest move had been to file a motion requesting that the order be stayed, asking for 120 days to show that it can complete the project in a timely manner and an expedited ruling so that it could still take part in next week's FCA 16.

But FERC again sided with ISO-NE over the developer, writing in its order that NTE has not met the standard of proving that being removed from the capacity market would cause "irreparable harm."

"NTE's speculation on these matters falls far short of the substantiation needed to show irreparable harm absent a stay," the commission wrote.

The New England Power Generators Association had *joined* ISO-NE in asking FERC to deny the stay, writing that allowing Killingly to take part in FCA 16 as a "phantom" resource unlikely to enter commercial operation would cause significant harm to other capacity resources participating in the auction. ■

— Sam Mintz

Environmental activists protest Connecticut's approval of the Killingly Energy Center in 2019. | *© RTO Insider LLC*

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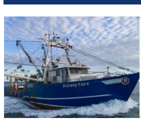

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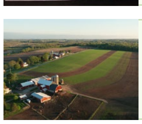

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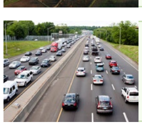

Conn. Advocates Seek 'Upgrades' to 2008 Climate Law NetZero Insider

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MISO News

MISO, SPP Roll out $1.755B Joint Tx Portfolio

Collaborative Effort Proposes 7 Projects; Would Save Customers $971M

By Tom Kleckner

MISO and SPP staff on Friday gave stakeholders their first chance to discuss and comment on the Joint Targeted Interconnection Queue (JTIQ) *study*, the culmination of a rare collaboration by the RTOs that began in 2020.

Staff said during a joint stakeholder meeting that the study resulted in seven projects that would cost an estimated $1.755 billion and "fully resolve" its targeted transmission constraints. The projects, six 345-kV transmission lines and a 345-kV bus reconfiguration, would deliver $724 million and $247 million of adjusted production cost (APC) benefit to customers in the MISO and SPP footprints, respectively, with a cumulative benefit-to-cost ratio of 0.56.

Four of the transmission projects are in MISO's footprint in the Dakotas and Minnesota; one is in SPP's; and the last crosses the seam. The bus reconfiguration is in SPP's region.

David Kelley, SPP's director of seams and tariff services, said he was unsure whether other grid operators had undertaken a similar collaborative effort to produce what he called "pretty exciting" information. (See *MISO, SPP to Conduct Targeted Transmission Study*.)

"I wanted to just mention briefly how cool, honestly, it has been to be part of such a novel study that has never been conducted before, at least between SPP and MISO," he said. "You guys get to see the work as it's taking place … but you all really miss, I think, the interaction that takes place on a week-to-week basis between what has been a really good team of engineers, analysts and a number of other supporting cast members that have … worked so closely together to bring to you the product that we're very happy to share with you today."

SPP's power-flow models found the projects could enable as much as 53 GW of generating capacity for new interconnection projects on the seam. MISO's models came up with 28 GW of new capacity.

Asked why the RTOs' models were off, Kelley said their planning processes are "fundamentally different."

"We even started with somewhat of a different future in the production cost modeling," he said. "Even when you call the futures the same thing, different assumptions go into them. It's more indicative and should be viewed as qualitative."

David Johnson, an Indiana Utility Regulatory Commission staffer, asked to see the numbers in dollars per megawatt to interconnect to the system "because it says it's an interconnection study."

"Tell me what the [bogey] would be if all of these projects that are connected individually along the way and those interconnection costs," he said. "All these studies make tons of assumptions."

Staff agreed with Johnson that it would be a "monumental task." MISO's Andy Witmeier, director of resource utilization, said the capacity enabled calculations included generation enabled by JTIQ-mitigated constraints and additional generation by using unused capacity on mitigated constraints and the study's projects.

Witmeier said a supplemental study conducted by an SPP consultant found that, consistent with the JTIQ analysis, 60% of the constraints assigned to MISO interconnection customers for mitigation could be addressed by the joint portfolio. The consultant's work also indicated the portfolio alleviated the need to mitigate 44% of the constraints — representing more than $301 million of the assigned network upgrade costs — in an SPP study cluster.

Cost allocation conversations are ongoing and additional stakeholder meetings will be scheduled in the first quarter, staff said.

"I believe it's important to continue cost allocation discussions, but under the banner of the JTIQ," Witmeier said. "We want to come up with cost allocations to hopefully get these projects built."

Staff have already run modifications revising the joint operating agreement's queue priority through the stakeholder process in both RTOs. A joint filing at FERC is expected in the next couple of weeks.

Stakeholders have until Thursday to provide feedback on the JTIQ study; a final report is expected Feb. 10.

The JTIQ study began as a mechanism to identify transmission projects required to address the significant transmission limitations restricting the interconnection of new generation near the SPP-MISO seam. Recognizing that large-scale transmission often provides multiple benefits, the study's "novel" approach meant simultaneously considering whether transmission necessary to unlock the RTOs' bulging generation interconnection queues could also provide economic and reliability benefits to their transmission customers.

The team closely coordinated the grid operators' technical analyses, using each RTO's respective transmission and generation planning methodologies to determine the project requirements that would cost-effectively resolve the transmission constraints inhibiting new generation near their seam. Staff performed reliability, economic and transfer capability studies and coordinated with stakeholders to develop solutions that met the study's objectives. ■

JTIQ Portfolio	Location by RTO	Cost ($M)
Bigstone – Alexandria – Riverview – Quarry – Monticello 345 kV	MISO	530
Jamestown – Ellendale 345 kV	MISO	165
Bison – Hankinson – Big Stone South 345 kV	MISO	476
Brookings Co – Lakefield 345 kV	MISO	331
Raun – S3452 345 kV	MISO - SPP	144.4
Auburn – Hoyt 345 kV	SPP	90.5
Sibley 345 Bus Reconfiguration	SPP	18.8
Total Cost of Portfolio of Projects	MISO - SPP	1,755.70

The draft JITQ portfolio of projects | *MISO, SPP*

MISO News

MISO Hosts First In-person Meetings amid Pandemic

By Amanda Durish Cook

CARMEL, Ind. — MISO last week pulled off a series of in-person meetings at its three offices almost two years since the COVID-19 pandemic began.

The RTO held on-site committee *meetings* simultaneously in its offices in Carmel, Ind.; Eagan, Minn.; and Little Rock, Ark. Stakeholder attendance was sparser than usual with the Omicron variant peaking and company travel budgets bouncing back. Some speakers appeared through video conferencing.

"I will have to relearn to stand at a podium in front of stakeholders. It's been nearly two years," MISO's Jeremiah Doner said in opening a Jan. 24 presentation on transmission cost allocation.

The grid operator required proof of full vaccination or a recent negative COVID test before admitting stakeholders into its conference rooms. Masking was optional, lunches were boxed and stakeholders had the option to sit more than six feet apart.

The grid operator gathered stakeholders in-person and off site late last year in Orlando, Fla., for its final quarterly board meeting of 2021. (See *MISO Board of Directors Briefs: Dec. 9, 2021*.)

MISO kicked off its first major meeting week of 2022 with a review of important subjects it plans to cover through the summer. It was the RTO's inaugural executive update, which it plans to hold on a near-monthly basis to keep its stakeholder community abreast of its goals and work timeline.

MISO's return to in-person meetings at its Carmel, Ind., headquarters Jan. 24 | *© RTO Insider LLC*

Wayne Schug, vice president of strategy, said MISO will debut a rolling 12- to 18-month management plan that lays out committee tasks, time reserved for analysis and filing deadlines.

Leadership said the footprint's rapid clean energy transition supports its case for long-term transmission planning and seasonal capacity auctions. It also said stakeholders should expect ongoing discussion in the first half of 2022 on its new participation models for energy storage and distributed resources; implementation of dynamic transmission line ratings; upgrades to its market-clearing engine; and an accreditation process for renewable, storage and hybrid resources.

Seventeen MISO utilities have emissions reduction targets greater than 80%, and five states in the footprint are considering 100% clean energy goals.

The topics will be explored under a lighter meeting schedule that calls for the RTO's main stakeholder committees to hold eight meetings each per year. MISO plans to evaluate the meeting schedule's effectiveness in May. (See *MISO Modifies Stakeholder Meeting Schedule*.)

Some stakeholders have objected to the slimmed-down schedule, arguing that MISO is facing industry changes that necessitate in-depth discussion and that stakeholders are supposed to dictate the frequency of meetings, not the RTO. ■

MISO Finalizes Long-range Tx Cost-sharing Plan

By Amanda Durish Cook

CARMEL, Ind. — MISO last week wrapped up discussion on its plans for sharing the costs of the first group of projects identified under its multistage long-range transmission plan.

The grid operator said it planned to file its cost allocations for long-range transmission projects with FERC by the end of January. The plan employs a 100% postage stamp allocation to load, limited to either MISO Midwest or MISO South subregions. Projects must have a minimum 100-kV rating, cost at least $20 million, and demonstrate a 1:1 benefit-to-cost ratio.

The cost-allocation design is predicated on the belief that initial projects coming out of the RTO's first long-range planning cycle are unlikely to produce benefits that seep into MISO South unless MISO increases the capacity of its subregional transmission transfer. (See *MISO to Test Long-range Tx Allocation Benefits*.)

Currently, MISO can only contractually flow 3,000 MW in the Midwest-to-South direction and 2,500 MW in the South-to-Midwest direction.

The grid operator plans to submit the long-range projects for board approval in mid-June. The first smattering of projects will be limited to Midwestern locations. (See *MISO Promises Long-range Tx Project Reveal Soon*.)

During a Jan. 24 meeting of the Regional Expansion Criteria and Benefits Working Group (RECBWG), MISO's Jeremiah Doner said the proposal has the support of most of the footprint's transmission owners.

Brattle: South Benefits Unlikely from Midwest

The Brattle Group, tasked with testing the benefits spread from MISO's last long-range projects in 2011 to see if they delivered advantages to MISO South, said the region saw only small advantages.

Brattle Group Principal Johannes Pfeifenberger said had members of MISO South — which only dates back to Entergy's membership in 2013 — been assigned project costs, it would not have met FERC's roughly commensurate benefit threshold. However, Pfeifenberger recommended that the grid operator keep a systemwide cost-allocation option open for projects that increase transfer capability between the two subregions or are physically located in both.

MISO said it will make a separate filing later to FERC where it will propose an evaluation method testing whether a project's costs should be shared on a subregional or systemwide basis. The RTO said it will allocate long-range projects' costs to the entire footprint if systemwide benefits can be proven through analysis.

"We understand that there aren't zero benefits that can go between the Midwest and South or vice versa," Doner said.

MISO's cost-sharing filing will arrive at FERC as multiple Midwestern states are either trying to or have passed rights of first refusal for their incumbent transmission owners. Wisconsin lawmakers last month introduced a bill that would prohibit the grid operator from awarding construction contracts to competitive developers. Michigan, Minnesota and Iowa have already enacted similar legislation.

MISO, meanwhile, is currently accepting applications from transmission developers to become qualified to bid on competitive projects.

Stakeholders: More Meetings on Cost Allocation

In addition to tweaking the long-range plan's cost allocation, the RECBWG also plans to establish draft allocation designs this year for a possible new MISO and SPP Targeted Market Efficiency Project category and projects stemming from the RTOs' Joint Targeted Interconnection Study. Those studies are aimed at getting interregional transmission projects built to clear up congestion on both sides of their seam and interconnect new generation.

Multiple stakeholders said they doubted that the RECBWG could accomplish those aims with only eight meetings scheduled in 2022. MISO is debuting a more infrequent stakeholder committee meeting schedule as it charts a return to in-person meetings during the coronavirus pandemic. (See *MISO Hosts First In-person Meetings amid Pandemic*.)

"Cost-allocations discussions are challenging. I don't think we have enough meetings on the calendar," Clean Grid Alliance's Natalie McIntire said.

"To be blunt, all we accomplished over 14 meetings [last year] was to dust off the [Multi-Value Project] allocation," WPPI Energy's Steve Leovy said of proposed long-range allocation. "I'm not confident we're going to be able to make progress given this calendar."

Doner said the meeting cadence allows MISO engineers to return to their offices and conduct analyses on and test allocation designs. He said the RTO will discuss the possibility of adding more RECBWG meetings this month. ■

| Xcel Energy

MISO News

MISO Weighing New Capacity Accreditations for Renewables, Storage

By Amanda Durish Cook

CARMEL, Ind. — MISO's resource adequacy stakeholder group is starting the new year by tackling new capacity accreditations for renewable and energy storage resources.

Lynn Hecker, senior manager of resource adequacy coordination, said the RTO hopes to have some new accreditation designs drafted by the end of the year.

She said during a Resource Adequacy Subcommittee (RASC) meeting Wednesday that a "fundamental shift" continues in the resource mix, with the generator interconnection queue dominated by renewable energy. Hecker said the footprint's record-breaking, weather-dependent generation warrants a fresh look at accreditation.

Hecker asked stakeholders for suggestions on what new accreditation designs might look like for renewables, storage and hybrid formats that are combinations of both.

Currently, a new availability-based accreditation for thermal resources is pending before FERC. MISO did not propose a new accreditation design for renewable or storage resources as part of its recent capacity auction redesign. Instead, it kept its effective load carrying capability (ELCC) method in place for wind resources, explaining that the calculation already accounts for output that varies by season. (See *MISO's Seasonal Capacity Proposal Opposed at FERC*.)

Some stakeholders have said that using two different methodologies for fossil fuel-fired and intermittent resources constitutes unfair treatment. RASC meetings during 2021 saw contentious debate on the appropriateness of applying an accreditation based on historical availability to fossil resources, with many members critical of the idea.

MISO plans to evaluate the usefulness of its wind resources' ELCC method . Staff said it might not accurately capture capacity contributions during the footprint's highest reliability risks.

The grid operator only has about 2 GW of solar currently participating in its markets, not enough yet to provide the historical data the ELCC relies on.

Hecker said solar is poised for explosive growth. "We feel like this is the appropriate time for us to start looking into solar accreditation changes," she said.

Lapeer Solar Park | *DTE Energy*

Hecker also said MISO will first focus on renewable energy accreditation before proposing capacity credit treatment for storage resources.

When pressed by stakeholders, she said she couldn't yet pin down a gigawatt threshold for participating energy storage before MISO would need an accreditation method.

"The magnitude of it cannot be overstated. We're seeing more rapid change of the industry than at any point in our careers," said the Brattle Group's Sam Newell, who was contracted by the RTO to give advice on accreditation.

Newell called out record wind and solar additions, increasing demand response, changing daily load shapes and climate change as affecting capacity contributions.

"And now we're in the news about reliability, about the transformation to clean energy," he said. "Accurate accreditation is key to verifying adequate supply, signaling adequate planning … and identifying the economic tradeoff between resources."

Newell said an ELCC calculation still "makes a lot of sense." He said grid operators will need "quite a few years of data" to model energy-limited and intermittent resource performance. He also said they must consider that load is also weather driven.

"We're going to have to argue about this a lot. That's the business we're in," Newell told the RASC.

Staff Preps for Annual Auction

MISO is gearing up for possibly its final annual capacity auction. In advance of the auction, stakeholders have asked whether the RTO can share information on capacity resources that plan to take seasonal outages. Staff said it might provide that data at the local resource zone level to avoid revealing proprietary information.

For the 2022-23 planning year, the grid operator *anticipates* a 121-GW coincident systemwide peak with 157 GW in total installed capacity and almost 128 GW in total unforced capacity.

Fleet-wide, MISO's wind capacity resources will have a 15.5% capacity credit in 2022-23, down one percentage point from the prior planning year.

MISO will conduct the Planning Resource Auction in early April. ■

MISO News

MISO Moves to Restrict Emergency Commitments

By Amanda Durish Cook

CARMEL, Ind. — MISO has come up with one possible fix on how it could more easily access its resource stack outside of emergencies: prohibiting some resources from using an emergency commitment status.

The tightened ruleset is poised to affect units that have been designated to meet the grid operator's resource adequacy requirements (RAR). Currently, such resources can use an emergency commitment status in the energy markets, making their entire output unavailable unless there's a generation emergency. The emergency commitments don't affect the resources' capacity credits.

MISO says wider access to its capacity is crucial to "ensure reliable and efficient market outcomes."

The RTO's Dustin Grethen said during a Resource Adequacy Subcommittee Wednesday that restricting those units from making emergency-only offers could make a noticeable difference in the footprint's resource adequacy.

Dustin Grethen, MISO | © RTO Insider LLC

Some stakeholders asked that MISO not altogether prohibit RAR resources from making emergency offers, especially for the top-end, emergency range of their output.

"We thought this should affect their accreditation instead of them just not being able to do it," MISO Independent Market Monitor Michael Chiasson said of RAR units' emergency-only statuses.

Customized Energy Solutions' David Sapper said MISO's proposal was "draconian."

"It does seem to me there's a difference between a resource that's in an emergency commit status for two days versus one that's in for two months," WEC Energy Group's Chris Plante said, noting that he was not communicating his company's position.

Some stakeholders also pointed out that state emission regulations dictate that some generators only run in emergency situations.

MISO has spent several years searching for solutions that will improve its resource availability, which it says has been steadily worsening. It says it needs a clearer picture of what capacity is accessible to it and when.

The RTO's Reliability Subcommittee plans to discuss and finalize the proposal in the second quarter. ■

MISO News

MISO Market Subcommittee Briefs

MISO Continues Dual-use Storage Considerations

CARMEL, Ind. — MISO is making slow progress on its plans to handle electric storage assets that aim to provide transmission services while also offering into the energy markets.

During a Market Subcommittee meeting Thursday, American Transmission Co.'s Bob McKee said his company intends to use the $8.1 million, 2.5-MW Waupaca Area Storage Project in Wisconsin for market and transmission purposes. The project was approved under MISO's 2019 Transmission Expansion Plan as the RTO's first — and currently only — transmission-only storage asset. It's expected to be in service late this year.

"We want a clear path to know what we need to do to pursue this," McKee said, referencing MISO's allowing the project to furnish market services when it's able. "We would urge MISO not to delay."

MISO's Michael Robinson said the grid operator might pursue one-off service agreements for its first dual-use energy storage projects instead of trying to finish lengthy tariff edits in time for interconnection.

"We think we have a defined path for where we're going here," Robinson said.

MISO has said for several years that it likely will require dual-use storage to first enter the generator interconnection queue before submitting energy offers, like any other generation asset seeking grid treatment. The Waupaca project has yet to apply to enter the queue.

Robinson said storage serving as transmission assets will be free to participate in any market, provided it can still address a transmission need.

But he said MISO and stakeholders still have work ahead regarding how the resources will collect both market compensation and transmission revenue requirements without being overcompensated. Robinson also said MISO must figure out whether storage assets should prioritize their market obligations or their transmission obligations during maximum generation emergencies.

Multiple stakeholders urged MISO not to rush tariff changes. Clean Grid Alliance's Natalie McIntire asked for a "robust" stakeholder process that "fleshes out all details" before it drafts an overarching revision filing.

Market Interface Retirement Postponed

MISO has delayed retiring its aging market user interface (MUI) until Feb. 15 to accommodate members who haven't yet switched to the new system.

"Everyone knows the end is near for the legacy MUI," MISO's Shawn McFarlane warned. "I think this is it; there won't be any further pushback in terms of dates."

Staff originally intended to retire the interface on Jan. 18, but some market participants have been slow to migrate their operations to the new system. The grid operator has been running both the old and new interfaces in parallel since early September.

Roughly 300 MISO customers use the non-public MUI to make energy offers and bids in the MISO markets. The upgrade is part of the RTO's ongoing market platform replacement.

The grid operator is entering the fifth year of a multistage swap of its older, more rigid market platform for a newer modular one that can host more complex market offerings.

2 Conservative Ops Declarations in January

Frigid weather compelled MISO to declare conservative operations twice in late January.

The grid operator issued the alerts Jan. 20-21 for its South region and again on Wednesday for the northern part of its Midwestern footprint. Neither alert escalated into a maximum generation emergency or warning.

Under conservative operations, MISO requests members return generation and transmission facilities undergoing maintenance to service, if possible.

The RTO earlier declared conservative operations and a maximum generation emergency warning in the first week of January for its Central and North regions. Cold weather was again the culprit behind the close shave. (See *Near-emergency Follows MISO's Winter Warnings*.)

MISO has been warning stakeholders since last fall that a generation emergency was a real possibility in January. While it experienced one close call, the month is nearly over and the system remains emergency-free.

MISO Independent Market Monitor David Patton said he has observed more coal-fired generation usage in the footprint with high natural gas prices. However, he said some facilities have been conserving coal to preserve their winter inventories, as railroad coal deliveries remain dogged by labor shortages.

Patton said that strategy will likely reduce coal capacity factors in winter. He added that he's working with resource owners so that coal resources' facility-specific reference levels "reflect the opportunity costs associated with maintaining winter coal inventory." ■

– Amanda Durish Cook

Sebree Station in a snowstorm in 2021 | *Big Rivers Electric Corp.*

NYISO News

Con Ed to Refine $4B Offshore Tx Plan for NYC

By Michael Kuser

Consolidated Edison must resolve several regulatory concerns before being authorized to build a new $4 billion substation complex in New York City dedicated to interconnecting offshore wind projects.

Those concerns took shape when the New York Public Service Commission issued a Jan. 20 *order* directing state solicitations for OSW proposals to require "mesh-ready" transmission plans, part of the broader effort to develop rules implementing the Climate Leadership and Community Protection Act (CLCPA), which requires that 70% of the state's electricity generation come from renewable resources by 2030 and that generation be 100% carbon-free by 2040.

The PSC also asked Con Edison to supply detailed plans for a wind energy interconnection hub — and specifically one in lower Manhattan allowing the connection of up to 6 GW of OSW projects (Case No. *20-E-0197*). (See *NYPSC Mandates Meshed Offshore Tx Grids*.)

"We look forward to providing more details on the benefits of these projects," Con Edison spokesman Karl-Erik Stromsta told *RTO Insider*.

Changing Landscape

"Time is of the essence," the commission said in its order, noting that the PSC and Con Edison are both aiming at moving targets in their efforts to identify the location for a substation. For example, the Rainey substation, which the state's three-part power grid *study* last January identified as a good candidate to integrate OSW, has since been claimed by the Clean Path New York (CPNY) project to bring upstate solar and onshore wind into the city.

"The CPNY project is expected to carry generation associated with up to 1,300 MW of capacity, making it highly unlikely that the same substation can feasibly accommodate an additional 1,250 MW of offshore wind generation as assumed in the base case of the OSW study," the commission said.

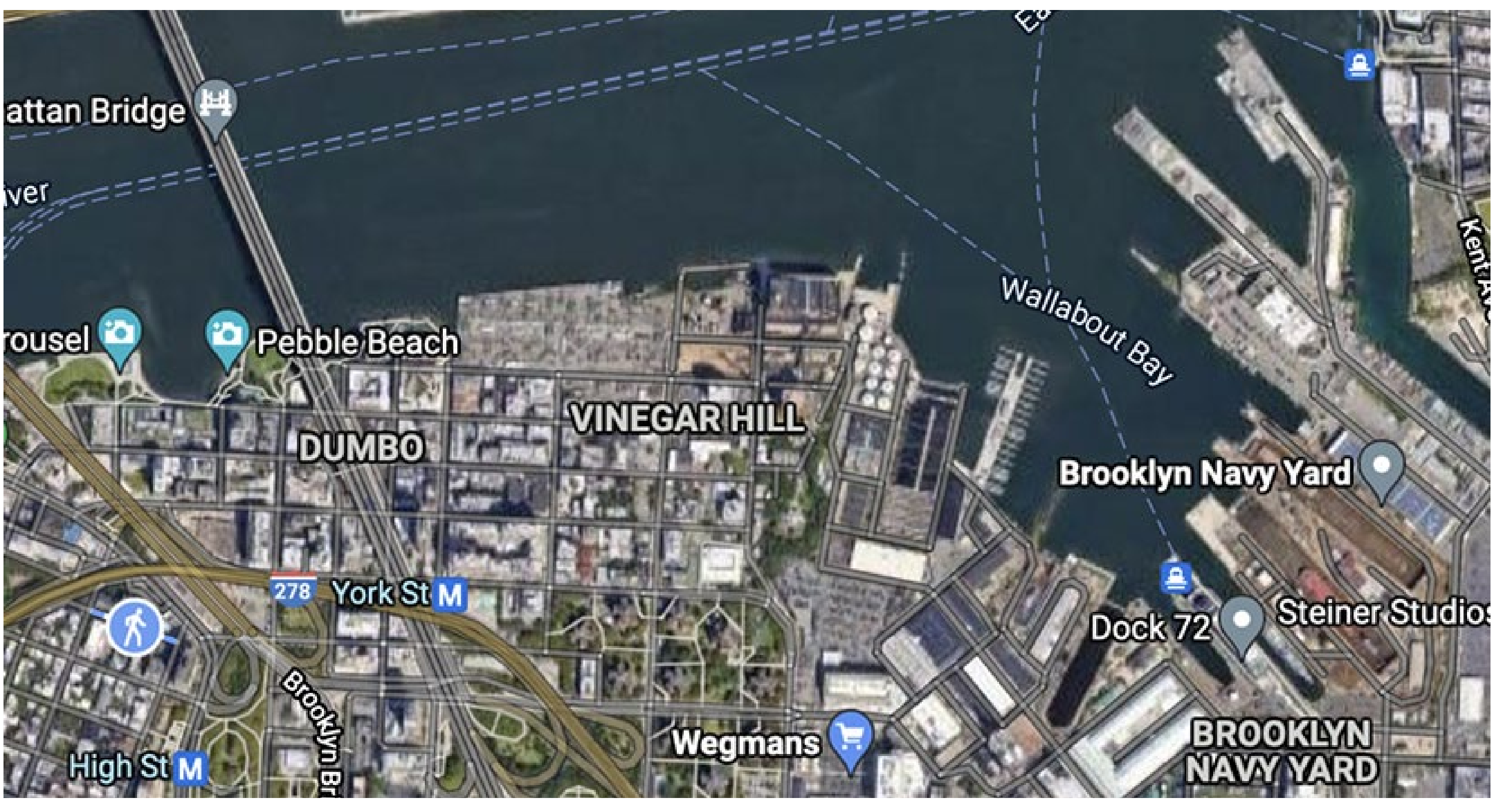
In March 2021 *comments* on the grid study, Con Edison reiterated earlier proposals for two New York City Clean Energy Hubs.

The first hub would create points of interconnection (POIs) for four 750-MW connections — or 3,000 MW total — and could be placed in commercial operation by summer 2027.

The second hub would create POIs for two new connections for about 1,500 MW total and simultaneously transfer load from three other constrained load pockets on Con Edison's 138-kV system, relieving transmission constraints and reducing the load's dependency on local fossil fuel power plants to maintain local system reliability. This project could be placed in commercial operation by summer 2029.

Con Edison first proposed the hubs in a local transmission and distribution *report* filed by all the state's utilities in November 2020. The various utilities reported on their T&D status and proposed Phase 1 projects — traditional utility investments that address system reliability or resilience issues — and Phase 2 projects intended primarily for achieving CLCPA goals.

The PSC last April approved $800 million in cost recovery by Con Edison for three Phase 1 projects known collectively as the Transmission Reliability and Clean Energy (TRACE) projects. The projects are needed for reliability in 2023 and 2025 because of the retirement or unavailability of 399 MW of peaking generation made to comply with the state Department of Environmental Conservation's "peaker rule," new NOx regulations that go into effect



Map shows the area between DUMBO and the Brooklyn Navy Yard where Con Edison may site a new substation to inject up to 6 GW of OSW energy into the city. | *Google*

NYISO News

May 1, 2023 (*19-E-0065*). (See *NYPSC OKs $800 Million Tx Cost Recovery for Con Ed*.)

Climate Resilience

Con Edison is also collaborating with the Long Island Power Authority to consider ways to interconnect 9 GW of offshore wind. The grid study and ensuing analysis identified scenarios in which 6,000 MW of interconnections into New York City and 3,000 MW into Long Island minimized onshore transmission system upgrades and involved very limited OSW curtailments. The OSW portion of the study evaluated every New York City area and Long Island substation above 69 kV.

In addition, Con Edison identified the need to construct new feeders to redistribute the renewable energy throughout its local transmission system to both supply local loads and export to upstate load areas to prevent OSW curtailment.

The OSW analysis base case selected four POIs — with their injection capacities — in NYISO's Zone J (NYC): Farragut (1,400 MW), Rainey (1,250 MW), Mott Haven (1,250 MW) and West 49th St. (1,200 MW). Still unresolved is whether those POIs have the physical space necessary to accommodate the upgrades for the planned injections.

Given the cost and difficulty of finding land for new electrical equipment and operations in lower Manhattan, Con Edison is proposing to build its first hub on land it already owns next to the Farragut substation on the East River in Brooklyn.

The commission is requiring all OSW proposals to include plans for HVDC transmission to make the best use of limited space available for cables in the Narrows and the harbor. It asked Con Edison for "a reasonable forecast" of where it will put an onshore HVDC converter station and the costs of routing an AC transmission line from there to the hub.

The commission also asked the utility to describe its measures to enhance resiliency, given that the hub would be "geographically concentrating, at a minimum, 3,000 MW of offshore wind interconnections at a single substation that would sit directly adjacent to another large substation (Farragut)."

Specifically, the commission asked for further information on how Con Edison will mitigate the risk of storm damage to the co-located substations; how the substations can be protected from exposure to sea-level rise and static or dynamic flooding; and how the utility will comply with all applicable reliability criteria, including NERC standards for "extreme contingencies" as specified in NERC Standard TPL-001-4.

The PSC also wants the utility to document how it is considering use of advanced technologies in its analysis.

The commission noted comments by LS Power and NextEra Energy Transmission New York in response to the utility study that said despite sufficient detail for regulatory action, Con Edison's hub proposal should nonetheless be referred to the NYISO public policy planning process because it cannot be considered a local transmission project.

"While the commission expects to address procedural matters following its review of the additional information, the availability of the NYISO process should not interfere with our broad planning authority and review of the options for establishing cost-effective POIs in service of our overarching goal of meeting CLCPA mandates at the least cost to ratepayers," the commission said in its Jan. 20 order.

The PSC in October 2020 designated the New York Power Authority's $1 billion Northern New York transmission line as a high priority for meeting the state's renewable energy goals, bypassing NYISO's public policy transmission planning process and adopting criteria for identifying other such "priority transmission projects." (See *NYPSC OKs NYPA Project, 'Priority' Tx Criteria*.) ■

Project Name	Zone	Terminal A	Terminal B	Project Description	Estimated Project Benefit (MW)	Proposed In-Service Date	Order of Magnitude (OOM) Cost Estimate
NYC Clean Energy Hub #1	J	TBD	TBD	Clean Energy Hub to provide additional POIs into local system	3,000	2027	-
NYC Clean Energy Hub #2	J	TBD	TBD	Clean Energy Hub to provide additional POIs into local system and enable load transfer	2,180	2029	-
NYC Feeder 1	I, J	TBD	TBD	Each is a new local Feeder to unbottle renewable supplies	700	2027	-
NYC Feeder 2	J	TBD	TBD		700	2030	-
NYC Feeder 3	J	TBD	TBD		700	2030	-
Load Transfer	J	TBD	TBD	Rebuild 2 Area Stations; Load Transfer	406	2030	-
						Total:	$4.05B

Con Edison estimates from 2020 on approximately $4 billion in Phase 2 projects to bring renewable energy into the city from from both upstate and offshore. | *Con Edison*

NYISO News

NYISO Management Committee Briefs

Sector Meetings Postponed to April

In-person stakeholder meetings will resume March 1 at the earliest, and annual sectoral meetings have been pushed back a month to mid-April to allow them to proceed in person as much as possible, NYISO CEO Rich Dewey told the Management Committee on Wednesday.

"We continue to look at infection rates related to the pandemic, and we're starting to see some declines that we're hopeful that we'll be able to get back in person on March 1," Dewey said.

The sector meetings are an "exceedingly valuable" opportunity to meet with each of the individual sectors, he said, and they constitute the practical kickoff of the ISO's strategic planning process. The meetings give staff a chance to meet directly with stakeholders according to their line of business or sector for open conversation about what the ISO's priorities should be, he said.

"Those meetings are far more effective if we can do them in person, so in order to try to maximize or increase the potential that we can actually hold those meetings in person, we're going to push them back to the early and mid-April time frame," Dewey said.

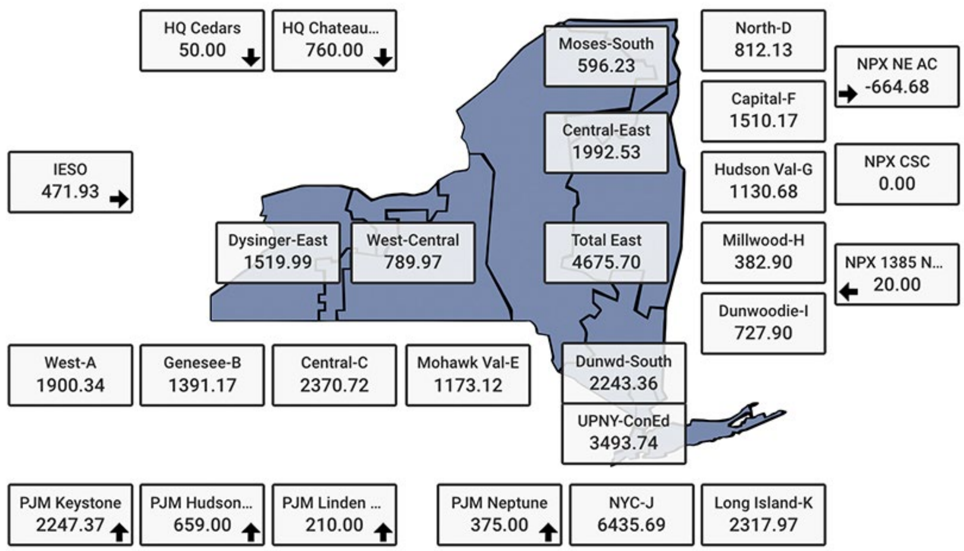


Chart shows NYISO zone loads and interface flows at mid-morning Jan. 26, 2022. | *NYISO*

Cold Weather Ops Going Fine

Since the second week of January, New York has experienced colder than average weather conditions — but not extreme cold — and the peak so far came in above 23,000 MW, about 97% of the ISO's forecasted peak winter load, COO Rick Gonzales said.

Natural gas prices during January were significantly elevated and have ranged from $15 to $25/MMBtu, reaching as high as $35/MMBtu for some of the eastern New York gas hubs, he said.

"That has translated into significantly higher energy clearing prices in eastern New York and even throughout the state. ... You might be aware we've often seen $200/MWh energy prices and higher throughout eastern New York," Gonzales said.

New York and New England usually have slightly higher energy prices than neighbors Ontario, Quebec and PJM, he said.

"Quebec is actually almost not an importer to New York during these colder weather periods, but we are actually exporting to Quebec," Gonzales said. "And Ontario and PJM power transfers are typically into New York, so the market systems are doing what we would expect, but ... we are seeing the ties being fully utilized in almost all directions."

NYISO is continuing to allow certain transmission work to proceed, except for on very cold days, he said. ■

— Michael Kuser

Northeast news from our other channels

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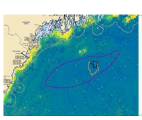

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NYISO News

NY Officials, Stakeholders Discuss Utilities' Tx Planning Process Proposal

By Michael Kuser

New York's local transmission and distribution system owners on Thursday recommended that state regulators approve a coordinated grid planning process (CGPP) and revised benefit-cost analysis (BCA) method as *proposed* by them in December (*20-E-0197*).

The New York Public Service Commission in September *established* a category of public policy transmission investments and directed investor-owned utilities to revise their proposed benefit-cost analyses. (See *New York Adopts Groundbreaking Tx Investment Rules*.)

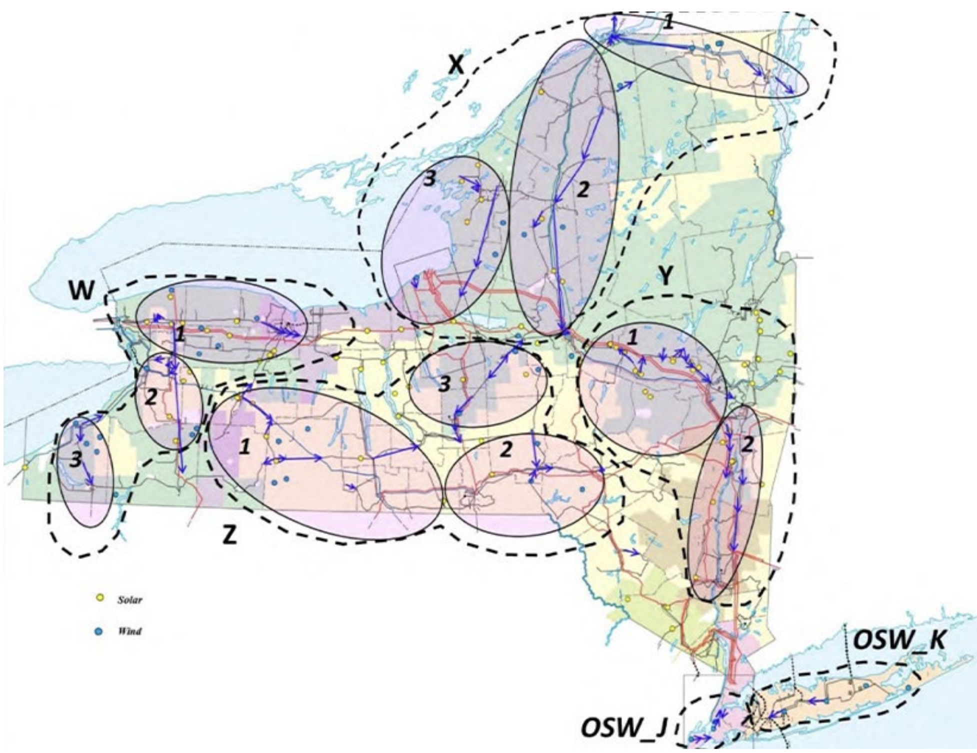
"The CGPP will facilitate technical collaboration between planning authorities and vetting of the existing system studies to ensure consistency between all studies, eliminating confusion and potential conflicting information," Bart Franey, National Grid supervisor of regulatory strategy, said to more than 220 participants at a technical conference held by the PSC.

"Once established, the CGPP will align system representation planning tool assumptions and other key constraints to drive consistency between all CLCPA-based studies [and] will be used to inform the market policymakers on the cost and viability of future interconnections," Franey said, referring to the Climate Leadership and Community Protection Act, which requires that 70% of New York's electricity generation come from renewable resources by 2030 and that generation be 100% carbon-free by 2040.

The utilities group include the state's IOUs, as well as the Long Island Power Authority. Staff from the Department of Public Service (DPS), the New York State Research and Development Authority (NYSERDA) and NYISO helped shape the proposals, on which interested parties can *submit* comments until March 21.

The revised BCA approach would use capacity expansion analyses. Costs would be evaluated on a dollars-per-megawatt basis for transmission and non-wire alternatives (NWAs). Benefits would be evaluated as the incremental amount of energy delivered to load as a result of reduced curtailments and the capacity of additional renewable generation that can be interconnected.

Projects would be ranked on the basis of metrics and criteria to be developed in collaboration with DPS staff, the utilities said.



The PSC's Phase 2 Order cited this NYISO graph depicting renewable generation pockets in the New York Control Area. | *NYISO*

New Technologies and More

The utilities considered several new and emerging technologies in their potential projects, including power flow control devices, dynamic line ratings and energy storage, the commission said, noting several "areas of concern" characterized by the presence of existing renewable generation that is already experiencing curtailments and a strong level of developer interest that exceeds the capability of the local transmission system.

FERC in December ordered transmission owners to stop the use of static line ratings in evaluating near-term transmission service, which it said will improve accuracy and transparency, and increase utilization of the grid. (See *FERC Orders End to Static Tx Line Ratings*.)

"Modifying the rating of a given transmission line throughout some given period rather than solely having seasonal based ratings, as is the conventional practice, can be taken into consideration in operations and planning, so that's a very recent order," said Zach Smith, NYISO vice president of system and resource planning. "From NYISO's perspective we're looking at it and considering what we do on compliance for that."

PSC orders in this proceeding have specifically pointed to DLR as a technology that may help the state get more CLCPA benefit at low cost, said Elizabeth Grisaru, deputy director of the DPS' Office of Electric, Gas and Water. "The commission has specifically pointed to [DLR] as one of the technologies our utilities should be considering when developing and proposing" their projects.

The crux of the grid analysis is to identify the placement of generation that can optimally use existing transmission on both the bulk and non-bulk systems, and those siting assumptions and land-use assumptions are going to be critical, Franey said.

Transmission providers are hoping for long-sought-after changes on FERC's Advance Notice of Proposed Rulemaking, a wide-ranging inquiry into the commission's rules on transmission planning, cost allocation and generator interconnection. (See *Transmission Industry Hoping for Landmark Order(s) out of FERC ANOPR*.)

The ANOPR proceeding will likely have impacts not only on the comprehensive system planning process, but on the way that that interacts with various policies, such as the interconnection process and how the system

NYISO News

is planned as a whole relative to generation coming forward, Smith said.

"Depending on what comes out of that FERC proceeding, presumably an order at some point, it could be a great opportunity for the NYISO, our stakeholders, for all of us to be working together on what's the most efficient planning process," Smith said.

Advisory Council Makeup

The utilities also proposed creating a new advisory council to manage the planning cycles.

The scope of work would be developed in the first stages of the CGPP by the council, said Martin Paszek, section manager for transmission planning at Consolidated Edison.

"I would try to keep the council as one group and maybe with subgroups ... but not have two separate groups that are losing the coordination we're trying to achieve," said Bill Acker, executive director of New York Battery and Energy Storage Technology Consortium (NY-BEST).

A planning group with a distribution subgroup would work well, agreed Zack Dufresne, executive director of the New York Solar Energy Industries Association (NYSEIA).

The proposed process is two-pronged, with the first being NYISO's local transmission owner planning process, wherein utilities' specific content and technical information regarding transmission investments would be reviewed and discussed openly, Franey said.

"The second prong to our stakeholder engagement plan really adopts a couple of models that exist in New York today such as the New York State Reliability Council or the Climate Action Council, [which] are very useful at leveraging stakeholder input on a more tactical basis," Franey said.

The council would invite information that utilities aren't experts in, such as generation development and land use, so it would consist of representatives not only from utilities and the state, but also from community organizations and renewable energy trade associations, he said.

"We envision that these industry organizations or groups would nominate a rep and an alternate to set up a lot of the critical input that would then translate into assumptions for modeling purposes," Franey said.

In thinking about stakeholder engagement, the DPS considered its own Interconnection Policy Working Group and Interconnection Technical Working Group structures, which "are pretty good models," Grisaru said.

One important group that wasn't in the proposal is consumers, who "absolutely" need to have a voice in the process, said Couch White attorney Kevin Lang, representing New York City.

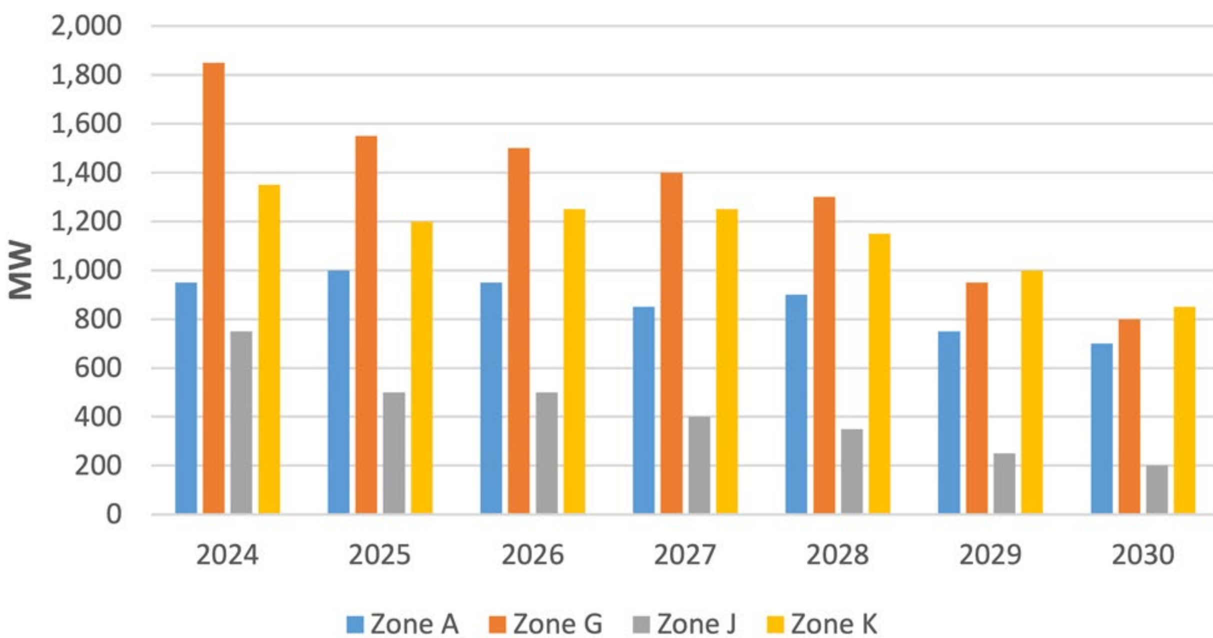
"I believe there are a lot of people that are participating this morning who are not active in the NYISO process, and if what we're talking about is distribution and local transmission, which is under PSC purview, I question whether or not a NYISO process that looks at the bulk system is the right venue to be talking about distribution and local transmission issues and whether or not the audience is even the correct audience for those discussions," Lang said.

Lang had an ally in Erin Hogan of the state's Utility Intervention Unit.

"Allowing developers to select sites very remotely and then have the expectation that consumers will be recouping costs and the investments that might need to expand the headroom does not seem to be wise, leaving consumers too far out of the loop," Hogan said.

She suggested informing county executives of the planning discussions so they can share the information and make communities knowledgeable about the decisions being made and how people might be able to participate.

"I want to be clear today that this is the starting point for this effort," said Tammy Mitchell, director of the DPS Office of Electric, Gas and Water. "Much more work and stakeholder input will be needed to fill out the details of the process and align [utilities] and New York ISO activities to support holistic views of CLCPA needs, so there will be many other opportunities to ask questions and provide input in the planning process." ■



NYISO analysis found tightening margins across the New York grid through time, with a margin of only 200 MW in New York City (Zone J) and only 700 MW in western New York (Zone A) by 2030. | *NYISO*

PJM Weighs Options on Hill Energy FTR Default

By Michael Yoder

PJM is requesting input from stakeholders on a course of action after a member defaulted on its portfolio in the financial transmission rights market, potentially leaving members having to cover millions of dollars.

Nigeria Poole Bloczynski, PJM | © *RTO Insider LLC*

At Wednesday's Markets and Reliability Committee meeting PJM's Chief Risk Officer Nigeria Poole Bloczynski *reviewed* the timeline of events that led to the default of Hill Energy Resource & Services, a member of the RTO since 2012.

"We are committed to transparency, and we're just as committed to providing as many opportunities as we can to provide feedback," Bloczynski said.

New rules in PJM initiated after the GreenHat Energy default in 2018 were designed to provide more information to members on defaults in the financial markets. GreenHat acquired the largest FTR portfolio in PJM between 2015 and 2018 but defaulted on the portfolio in June 2018, leaving PJM stakeholders to cover more than $179 million in the market. When the company defaulted, GreenHat had only $559,447 in collateral on deposit with PJM. (See *Doubling Down — with Other People's Money*.)

Timeline

Bloczynski said PJM issued an approximate $921,000 margin call on Jan. 10 to Hill because its December positions, which had a positive value, rolled off the RTO's books. The margin call was due by 4 p.m. on Jan. 11; Hill did not make it and was subsequently declared in default.

PJM withheld payment to Hill of outstanding December and January settlement amounts totaling $735,000 to partially satisfy collateral call. The RTO currently holds $6.1 million in collateral cash from Hill against the defaulted portfolio.

An additional margin call went unmet on Jan. 13, and Hill defaulted on a payment Jan. 24.

Bloczynski said Hill has been in good standing since it joined the RTO in 2012 and has been adequately collateralized. PJM completed a "Know Your Customer" (KYC) procedure and background check on Hill in 2021 with no adverse findings.

Its FTR portfolio represented 0.3% of PJM's overall FTR market transactions as of Dec. 31. "It was a relatively small portfolio considering the overall size of the FTR market," Bloczynski said.

Prior to the Dec. 22 FTR auction, Bloczynski said Hill had a "substantial amount of excess collateral" posted with PJM. After the auction, Hill requested a return of excess collateral, leaving $5.4 million in place against a requirement of $5.1 million. Its portfolio had a positive mark-to-auction value and an FTR credit requirement of $5.1 million, including a $4.1 million FTR requirement and $1 million in additional restricted collateral.

The portfolio goes through May 2025. The company only participated in the FTR market and did not serve any load.

"There were no red flags identified and no previous payment or collateral default history within PJM or what we uncovered through the KYC and background check," Bloczynski said.

Evaluating the Exposure

Following default, PJM began an analysis of open positions of Hill's portfolio to assess exposure. The initial analysis showed a subset of the portfolio experiencing "volatile congestion losses" in January because of a short position on the Greys Point-Harmony Village constraint in the Dominion zone. Work started on the line at the beginning of January and is expected to go until December 2023.

As of Jan. 24, PJM had issued about $83 million in collateral calls related to the volatility on the constraint. Approximately 20 impacted companies satisfied the calls, but not Hill. The company's short position across the constraint path extends from last month through May 2023 for a total of approximately 174 GWh, Bloczynski said, creating risk of "significant degradation" of portfolio value from the December mark-to-auction values. PJM is reviewing other portfolios that may be experiencing losses and issuing collateral calls.

Jan. 10 – PJM issued an approx. $921,000 margin call to Hill because its December positions, which were positive, rolled off our books. Margin was due Jan. 11.

Jan. 11 – Hill did not meet collateral call and declared in default. PJM withheld payment to Hill of outstanding December and January settlement amounts of $735,000 to partially satisfy collateral call. PJM currently holds $6.1 MM in cash from Hill.

Jan. 12 – Members notified of default.

Jan. 13 – PJM issued additional collateral calls.

Jan. 24 – Payment default

Timeline of Hill Energy default in PJM | *PJM*

PJM News

Bloczynski said there are already known losses of $2.8 million from the beginning of January through Jan. 20 on the defaulted portfolio. Depending on market conditions of day-ahead prices, the final January dollar numbers could be "more or less."

PJM anticipates an estimated loss of $300,000 from February through May based on the latest February FTR auction for the balance of the planning year and a $4.6 million loss from June through the end of the FTR portfolio in May 2025.

That brings the total of estimated losses to $7.2 million in losses, against the $6.1 million PJM holds in collateral.

"It's very likely the amount that we have will be inadequate given the unusual congestion patterns we've seen so far," Bloczynski said.

Options

Tim Horger, PJM | © RTO Insider LLC

Tim Horger, director of PJM's forward market operations and performance compliance department, provided some of the options available in the RTO's "toolbox" to deal with the default, as required under Schedule 1 of the Operating Agreement. They include allowing the positions to go to settlement, or liquidating the positions by offering them for sale in an upcoming auction.

Horger said the January and February positions in the portfolio will go to settlement because of the timing of the default. But "there could be a combination of different ways to handle" the other positions, he said.

The OA language was adopted by stakeholders last year, and PJM is still waiting to hear from FERC on approval of its filing (*ER22-797*). (See *PJM Stakeholders Endorse Initial Margining Proposal* and *Stakeholders Endorse PJM ARR/FTR Market Changes*.)

Horger said the first option is to allow the positions to go to settlement against day-ahead prices for a certain period or throughout the life of the portfolio through May 2025. He said if the positions are allowed to go to settlement, it could result in a "significant loss" depending on how the congestion on the line in the Dominion zone materializes over the next three years.

"It might not be practical to let them go to settlement for these longer-term positions because at that point the membership will be at risk of potentially higher costs," Horger said.

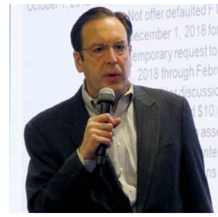
The positions can be liquidated in a normal or special FTR auction. Offering the portfolio for sale in a normal FTR auction allows the market to determine the value of the portfolio, Horger said, and it also removes the risk of future exposure because the positions are being taken off the books.

A special auction, Horger said, would be conducted in almost a "silent auction" fashion with only individual paths in the defaulted portfolio being bid on instead of being inserted into the larger FTR market.

Horger said PJM is interested in how much advance notice stakeholders would want before liquidating the portfolio in an auction. "The goal is to minimize losses to members."

Legal Update

PJM General Counsel Chris O'Hara gave an



Chris O'Hara, PJM | © RTO Insider LLC

update on the legal procedure in the default.

The RTO believes Hill was "adequately capitalized" and had "sufficient" capital to satisfy the margin calls, O'Hara said. It filed a complaint and request for expedited discovery against the company and its principal Lijin Chen, who had notified it that the company does not currently have sufficient funds to cover the defaulted portfolio.

O'Hara said PJM filed the court case in Texas to "eliminate personal jurisdiction issues" with Chen. Claims in the lawsuit include breach of contract, taking actions to avoid credit obligations and "piercing the corporate veil/alter ego." The RTO is pursuing an injunction to "seek to secure funds in the amount of the unsatisfied collateral calls," he said.

PJM CFO Lisa Drauschak said section 15.2.2 of the OA establishes a default allocation assessment formula to be used at the direction of the board. Ten percent of the default would be charged to every PJM member with a $10,000 annual cap, and 90% of the allocation is based on gross market activity, itself based on three months of gross billings. For the Hill default, the factor would include gross billings from November, December and January.

PJM will discuss the proposed settlement timetable at the Feb. 24 MRC meeting. A special session of the Members Committee is also scheduled for this Wednesday to further discuss the approach to the default with stakeholders. ■

PJM News

PJM, NJ Seek FERC OK for OSW Tx Process

State Would Fund Projects

By Rich Heidorn Jr.

PJM and the New Jersey Board of Public Utilities asked FERC on Thursday to approve their plan for using the "state agreement approach" (SAA) to build transmission to deliver the state's planned 7,500 MW of offshore wind (*ER22-902*).

Under the proposal, New Jersey would commit to paying 100% of the cost of the transmission but could seek to allocate some costs to other generation projects that use the additional capacity. PJM and the BPU said the SAA agreement, which they asked FERC to approve by April 15, is "an innovative and significant step forward" in meeting New Jersey's goal of developing offshore wind.

PJM proposed the state agreement approach to comply with Order 1000's requirement for procedures to address transmission needs driven by public policy requirements in the regional transmission planning process.

As approved by FERC, "the SAA mechanism is not a rigidly defined process in the PJM Operating Agreement," PJM noted. "Rather, the SAA process is intended to provide the flexibility needed to accommodate the breadth of policies that a state might wish to pursue and to allow that state to select the transmission solution(s) that best addresses its public policy goals."

The filing is a milestone in a process that began when New Jersey asked PJM on Nov. 18, 2020, to open a competitive window to solicit transmission proposals to connect its OSW. The window, opened last April, closed Sept. 17, 2021. (See *PJM, NJ Staff Brief Stakeholders on State Agreement Approach*.)

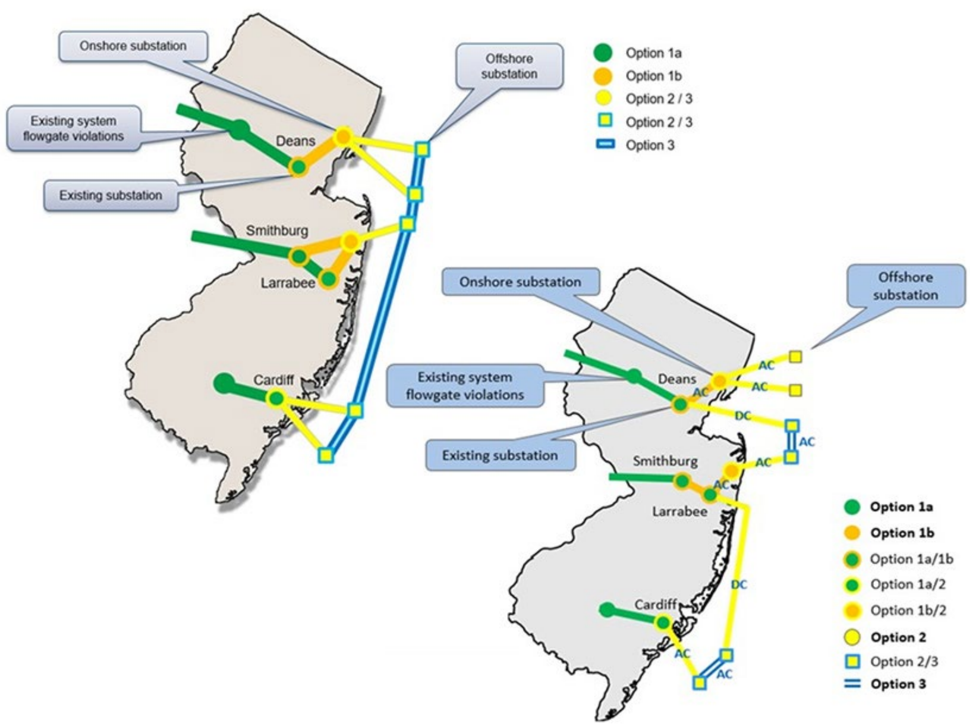
BPU President Joseph L. Fiordaliso called the filing "a critical next step on the pathway for efficient offshore wind interconnection between the approved wind farms and the onshore grid."

"New Jersey is once again leading the way on offshore wind through this agreement approach, which unlocks the potential for drastically minimizing community impacts while saving money for New Jersey's ratepayers," he added.

After PJM completes its review of the bids, they will be sent to the BPU to determine which, if any, of the proposed projects the state will agree to fund. According to PJM's filing, "BPU's competitive bid evaluation process will review price, risk, environmental and other factors."

"PJM's proven competitive process will allow the Board of Public Utilities to select an optimized, comprehensive solution that maintains electric reliability while advancing the state's energy policy goals," PJM CEO Manu Asthana said in a statement.

The BPU has awarded more than 3,700 MW of offshore wind generation: Ørsted's Ocean Wind 1,100-MW project and a combined 2,658 MW for EDF/Shell's Atlantic Shores Offshore Wind and Ørsted's Ocean Wind II.



PJM gave an example of how proposals to New Jersey's solicitation for offshore wind transmission projects may look. | *PJM*

Request

Specifically, PJM asked the commission to approve:

- the assignment of transmission capability created by SAA projects to OSW generators selected through New Jersey's solicitations;
- the requirement that OSW generators will be studied through PJM's interconnection queue;
- the granting of any incremental rights, if eligible, associated with any incremental transmission capability created by SAA projects;
- New Jersey's ability to obtain cost sharing from entities other than OSW generators that seek to utilize facilities created as part of an SAA project, including offshore transmission facilities and extensions to the onshore grid; and
- the ability of the BPU to assign some or all of the capability created by SAA projects to public policy resources other than OSW generators.

"Importantly, the SAA agreement does not consent to the selection of any SAA project(s), designated entities, or cost allocation methods by which to allocate the costs of any SAA project(s) to New Jersey customers," PJM said. "Before the NJ BPU can follow through with any of those next steps, it needs to know whether the commission will accept the terms and conditions contained in the SAA agreement. Commission acceptance of the SAA agreement would provide the NJ BPU the regulatory certainty needed to select and sponsor

PJM News

any suitable SAA project."

Future Filings

If the state selects one or more projects, there would be additional FERC filings specifying the project's scope, estimated cost, the entity or entities selected to construct it, construction milestones and proposed cost allocation.

PJM said it created the SAA agreement with the BPU "to reflect the complex realities and timelines associated with the development of offshore wind generation and any potential SAA project(s), while at the same time preserving the open access provisions of Order No. 888 and ensuring fair treatment of all other generators in PJM's interconnection queue."

"Since New Jersey's request to inject up to 7,500 MW of offshore wind into New Jersey via an SAA project(s) was known to customers entering the queue after Nov. 18, 2020, such circumstances are appropriately factored into the interconnection study process and may form the basis for assigning the customer new facilities to build or for allocating specific costs to subsequent customers," PJM said.

Solicitation	Capability Target (MW)	Capability Awarded (MW)	Issue Date	Submittal Date	Solicitation Award Date	Estimated Commercial Operation Date
1	1,100	1,100	Q3 2018	Q4 2018	Q2 2019	2024-25
2	1,200	2,658	Q3 2020	Q4 2020	Q2 2021	2027-29
3	1,200	N/A	Q3 2022	Q4 2022	Q2 2023	2030
4	1,200	N/A	Q2 2024	Q3 2024	Q1 2025	2031
5	1,342	N/A	Q2 2026	Q3 2026	Q1 2027	2033

NJ BPU offshore wind solicitation schedule | *PJM*

"PJM and the NJ BPU urge the commission to recognize the steps they have taken both to preserve fair opportunities for other generators in the queue and open access requirements while, at the same time, ensuring that both the generation and transmission components of the NJ BPU's SAA proposal can be effectuated on a coordinated and timely basis to meet the state's public policy goals. PJM urges against efforts to strictly 'pigeonhole' each component as being either a part of the interconnection process or the [Regional Transmission Expansion Plan] process without recognizing the important relationship between the two processes under the SAA process, as the failure to do so would render the SAA process meaningless." ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Dead Bus Replacement Logic Changes Endorsed

PJM stakeholders unanimously endorsed changes to the dead bus replacement logic for assigning prices to de-energized pricing nodes (pnodes) at last week's Markets and Reliability Committee meeting.

Vijay Shah, PJM | © RTO Insider LLC

Vijay Shah, lead engineer in PJM's real-time market operations department, *reviewed* revisions to *Manual 11: Energy and Ancillary Services Market Operations* designed to incorporate the changes that were introduced as part of a problem statement on five-minute dispatch and pricing in July 2020. (See *PJM Stakeholders OK 5-Minute Dispatch Proposal*.)

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

The new logic is based on Dijkstra's algorithm, an industry standard, to find a suitable replacement for de-energized pnodes. The manual changes include updated language to reflect the new logic.

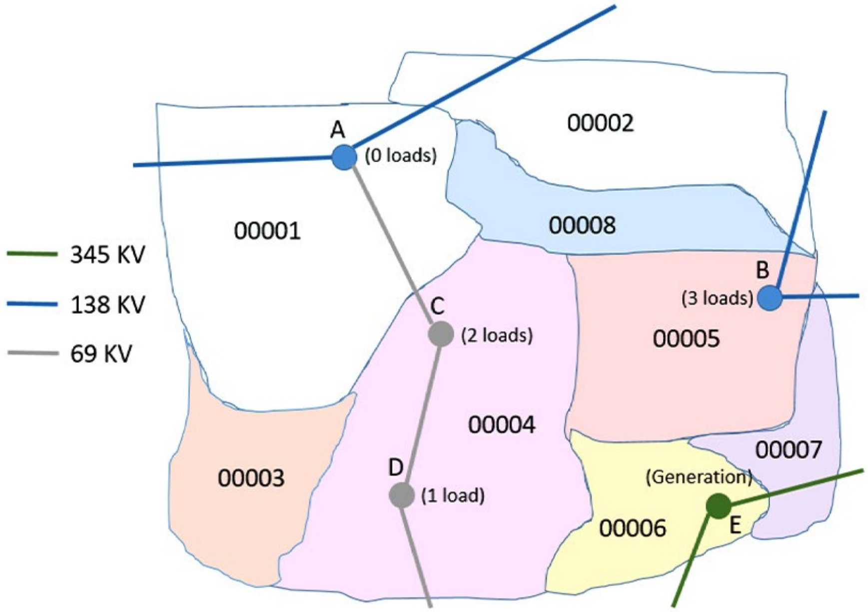
Shah highlighted a change to section 9.1.1: Intraday Offers Optionality that was not included in the first read at the December MRC, which clarifies language to state that a generation resource's fuel-cost policy only needs to be updated when opting into intraday updates for the cost-based schedule.

"We already had an ongoing effort to update the language in Manual 11, and we thought it would be good to include these changes as part of that," Shah said.

The new dead bus replacement logic and manual revisions will take effect March 1.

Fuel-cost Policy Standard Clarifications Endorsed

Members unanimously endorsed a joint PJM/Independent Market Monitor proposal regarding fuel-cost policy standards and penalty language.



Example of pnodes modeled in the PJM footprint. | *PJM*

Melissa Pilong, senior analyst in PJM's performance compliance department, *reviewed* the *proposal* clarifying fuel-cost policy standards in *Manual 15* and Schedule 2 penalty language of the *Operating Agreement*. The proposal was endorsed at the December Market Implementation Committee meeting. (See "Fuel-cost Policy Standards Proposal Endorsed," *PJM MIC Briefs: Dec. 1, 2021*.)

The changes would require that generation unit market sellers verify that all intraday offer triggers are specified in the unit's fuel-cost policy. The Manual 15 updates include changes to the intraday update triggers. Pilong said market sellers would need to have a one-time trigger to update the maximum allowable cost offer to opt into intraday offers. Another clarification to Manual 15 includes language that PJM or the Monitor can work with market sellers to extend their fuel-cost policies prior to their expiration.

OA updates include standards of review that must be systematic and verifiable. Fuel-cost policies would be required to provide a fuel price that can be calculated by the Monitor or PJM "after the fact with the same data available to the generation owner at the time the decision was made and documentation for that data from a public or a private source."

The changes now go to the Members Committee for a vote this month and would take effect upon approval by the PJM Board of Managers and FERC.

Virtual CC Proposal Endorsed

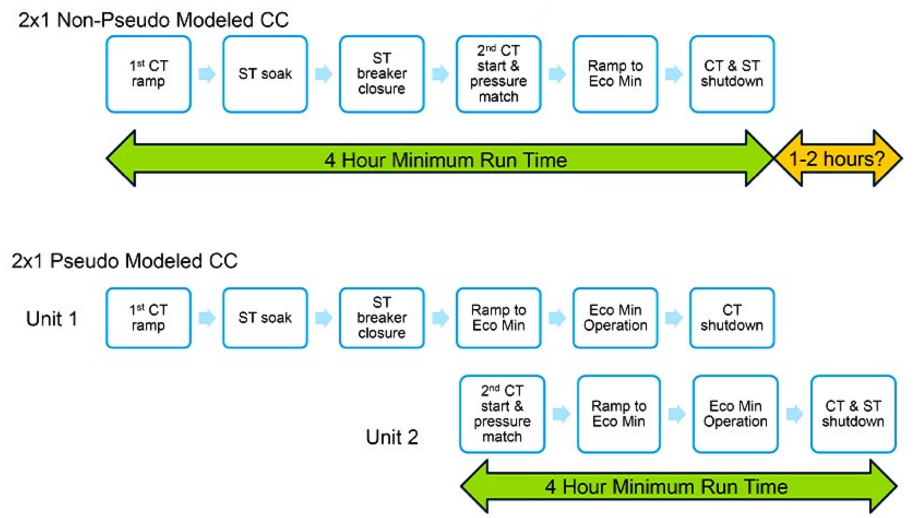
Stakeholders unanimously endorsed a proposal from Vistra addressing regulation for virtual combined cycles.

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

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

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

PJM News



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

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

"The proposal is not changing the process of regulation clearing, pricing or settlement," Olaleye said.

PJM plans on implementing the changes beginning March 1.

Consent Agenda

In the MRC consent agenda, members unanimously *endorsed* revisions to *Manual 38: Operations Planning* resulting from a periodic review. The revisions were originally endorsed at the Jan. 13 Operating Committee meeting and included minor changes. (See "Manual 38 Revisions Endorsed," *PJM Operating Committee Briefs: Jan. 13, 2022*.)

Members Committee

Sector Selection Challenge Proposal Fails

Stakeholders rejected a proposal at last week's Members Committee meeting seeking to change the way challenges can be made to sector selections in PJM.

The proposal, brought forward by Exelon and Public Service Enterprise Group from the Stakeholder Process Forum, received 45 votes in favor for a sector-weighted vote of 2.2, failing to meet the 3.33 threshold.

Sharon Midgley, Exelon | © *RTO Insider LLC*

Sharon Midgley, Exelon's director of wholesale market development, *reviewed* the proposed OA *revisions*. Several stakeholders questioned the proposal at the December MC meeting. (See "Sector Selection Challenge Process," *PJM MRC/MC Briefs: Dec. 15, 2021*.)

The issue of sector challenges has been a source of discussion at the Stakeholder Process Forum for the last 18 months. In 2020, Exelon and FirstEnergy requested that PJM more actively police stakeholder selections after the disclosure that an LS Power affiliate was improperly voting in the RTO's senior committees. (See *Exelon, FE Ask PJM to Tighten Sector Selection Process*.)

Under current rules, Midgley said, "questionable" sector selections of an existing member may only be challenged one time per year, coming within 30 days of the Annual Meeting. Challenges to a new member's sector selection must be made within 30 days of the member joining PJM.

In the last three years, Midgley said, PJM required changes to the sector selections of 14 members, determining that a sector modification was warranted for 88% of challenges.

"Our goal is to make sure going forward that we ensure the integrity of sector-weighted voting at PJM," Midgley said.

The proposed solution called for revising section 8.1.3 of the OA to say that any member may request that PJM review the qualification of another member to participate in a sector "if the basis for such challenged member's qualifications have not been subject to a sector challenge review in the prior 24 months, unless there is a good faith assertion of a material change in the challenged member's active and significant business interests with PJM."

The revised language also called for removing the 30-day requirement from the Annual Meeting. Midgley said the requirement can be "challenging" for stakeholders to do "proper investigative work" on a sector challenge.

Susan Bruce, counsel to the PJM Industrial Customer Coalition, said the ICC was "not in a position to support" the proposal. She noted that it takes "significant time" to go through the sector selection process. "I think there's value in having the orderly progression of having it be done once per year," she said.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said he could see the arguments in expanding the sector challenge process to any time, but he said he had "broader concerns" after talking to his members about the proposal. Poulos said he is concerned that there could be "cherry picking" in what PJM members are selected for a sector challenge.

"It's too limited and too narrow in the approach," Poulos said.

After the vote failed, Midgley said Exelon and PSEG were "disappointed by the outcome." A lack of a framework to allow stakeholders to appeal a sector selection on a "timely basis" can result in "inaccurate sector-weighted voting outcomes," she said.

Consent Agenda

Stakeholders endorsed two different items on the MC consent agenda. They included:

- tariff and OA *revisions* addressing several aspects of market participation by solar-battery hybrid resources. The revisions were unanimously endorsed at the Dec. 15 MRC meeting. (See "Solar-battery Hybrid Resources Endorsed," *PJM MRC/MC Briefs: Dec. 15, 2021*.)
- tariff and OA *revisions* addressing synchronous reserve deployment. The proposal, which was developed from discussions in the Synchronized Reserve Deployment Task Force (SRDTF), is meant to improve the deployment of synchronized reserves during a spin event. (See "Synchronous Reserve Endorsed," *PJM MRC/MC Briefs: Dec. 15, 2021*.) The proposal was endorsed with 18 objections. ■

— Michael Yoder

PJM News

PJM Stakeholders Approve RASTF Issue Charge

By Michael Yoder

PJM stakeholders approved an updated issue charge for the Resource Adequacy Senior Task Force (RASTF) at last week's Markets and Reliability Committee meeting after debating its out-of-scope items, including demand response.

Members approved the *issue charge* in a sector-weighted vote of 3.08 (61.6%), passing the necessary 2.51 threshold. The RASTF endorsed the draft issue charge with 59% support at its Dec. 7 meeting. The task force itself was approved by the MRC in October. (See "Resource Adequacy Charter Approved," *PJM MRC MC Briefs: Oct. 20, 2021*.)

Pat Bruno, PJM | *© RTO Insider LLC*

The scope of work in the RASTF is meant focus on a list of the issues identified by stakeholders at workshops held throughout 2021, as well as topics identified in the *letter* issued by the PJM Board of Managers on April 6, Pat Bruno, senior lead market design specialist in PJM's market design and economics department, said in *presenting* the updated issue charge.

While the RASTF's work will be "holistic," solutions for any of the topics to be discussed may be advanced for a vote in their own or in conjunction with other topics, Bruno said. A series of "check-ins" will also be scheduled periodically to assess whether any proposed solutions for the topics should advance for an earlier implementation date.

The key work activities approved in the issue charge include determining:

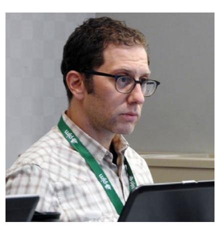
- whether a forward procurement of clean resource attributes should be pursued and investigate the inclusion of the social cost of carbon in PJM markets (A separate issue charge for the appropriate stakeholder venue will be developed for consideration by the MRC if the determination results in additional scope.);
- the types of reliability risks and risk drivers to be considered by the capacity market and how they should be accounted for;
- the desired procurement metric and level to maintain the desired level of reliability;
- the performance expected from a capacity resource;
- the qualification and accreditation of capacity resources;
- the desired obligations of capacity resources;
- if there are needed enhancements to the capacity procurement process;
- any remaining design details for a seasonal capacity market construct not addressed in other key work activities;
- if supply-side market power mitigation rules in the capacity market need to be enhanced; and
- if the fixed resource requirement (FRR) rules need to be synchronized with any changes made.

The issue charge also included three out-of-scope items. Those are:

- topics related to the minimum offer price rule, beyond those needed for consistency with the work in this issue charge;
- elimination of the FRR option; and
- removing DR as a supply resource.

Work in the RASTF is expected to be completed by the last quarter of 2023 in time for implementation in the 2027/28 Base Residual Auction in May 2024.

DR Debate



Steve Lieberman, AMP | *© RTO Insider LLC*

Steve Lieberman, vice president of transmission and regulatory affairs for American Municipal Power, *presented* an alternative issue charge removing DR as a supply resource from the out-of-scope items in the issue charge.

Lieberman said AMP supports DR participation in the Reliability Pricing Model and recognizes its benefit to consumers. He said discussion would not be "an attack on DR" or an attempt to end the DR business model.

AMP contends that the review of the capacity market should be a "holistic one," Lieberman said, and that excluding an "essential and important component" from the discussion like DR "does not serve our collective best interests." Lieberman said PJM members have expressed concerns that DR is a contentious issue, but that shouldn't be a qualifier for discussions in the stakeholder process.

"I get concerned when we start to carve out things that are in scope and out of scope, and in my mind, we are picking winners and losers," Lieberman said. "If indeed items that are deemed to be divisive and time consuming are out of scope, I think a lot of us are going to be on the bread line."

Paul Sotkiewicz of E-Cubed Policy Associates said he agreed that excluding DR could be "discriminatory." He said it "sets a very dangerous precedent" in the stakeholder process by eliminating discussion of a key issue.

"If it's divisive and time consuming, it probably means it's worth exploring at the end of the day," Sotkiewicz said.

Aaron Breidenbaugh, director of regulatory affairs for Centrica Business Solutions, said eliminating DR as a supply resource would be "tantamount to eliminating DR from the capacity market." Seeking to remove DR as a supply resource would be like expecting generation owners to support the total elimination of the capacity market, he contended.

Breidenbaugh asked what the point would be in considering something that has no chance to win approval by PJM stakeholders or at FERC. "This rises to an entirely different quantum of controversial as far as our side of the business is concerned."

Susan Bruce, PJM ICC | *© RTO Insider LLC*

Susan Bruce, counsel to the PJM Industrial Customer Coalition, said she would welcome a discussion on new ways DR can participate on the demand side. But removing DR as a supply source is an "existential issue" for those involved in DR, she said. There are too many large issues to deal with at the RASTF, including the market seller offer cap and clean procurement, to spend time on a discussion that could "bring down the ship."

"I fear it will become something that is too much of a distraction to allow for focused conversations on the things that we have that are immediately before us," Bruce said. ■

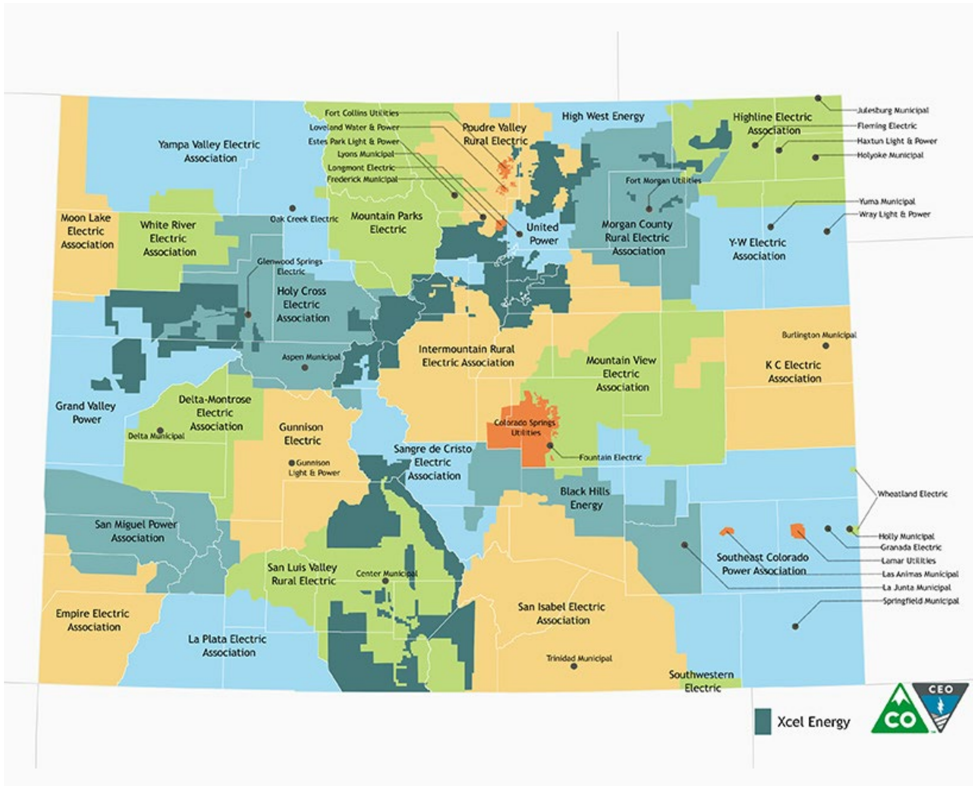
SPP News

Colorado Utilities Choose WEIS over WEIM

PSCo, Platte River, Black Hills Go with SPP's Market

By Tom Kleckner

Colorado utilities Public Service Company of Colorado (PSCo), Platte River Power Authority and Black Hills Colorado Electric last month said they plan to join SPP's Western Energy Imbalance Service (WEIS) market over CAISO's Western Energy Imbalance Market.



Public Service Company of Colorado, Platte River Power Authority and Black Hills Colorado Electric said they planned to join SPP's Western Energy Imbalance Service. | *Colorado Energy Office*

The utilities said the move will allow them to provide cost savings to customers and improve operational efficiencies. They expect to join WEIS in April 2023 and will continue to study long-term solutions for joining or developing an organized wholesale market.

"As we look at opportunities moving forward, this short-term step meets our energy needs to deliver clean, reliable and affordable energy to customers right now," PSCo President Alice Jackson said. "The energy imbalance market allows us to participate in an organized market while giving us the flexibility to explore a more permanent solution that will help us integrate more wind and solar energy onto our system."

SPP's Board of Directors on Jan. 25 approved an amended Western joint dispatch agreement (JDA) brought forward by the Western Markets Executive Committee that incorporates terms and conditions agreed upon by participants in the PSCo balancing authority. The WMEC met three times the week of Jan. 17 to hammer out differences.

The board's approval cleared the way for the three utilities to join SPP's WEIS. The JDA enables generation within its BA to be shared with Platte River, Black Hills and Colorado Springs Utilities (CSU).

PSCo paused a previous decision to join the EIM when CSU said last May it had decided to join WEIS. The Xcel Energy subsidiary approached SPP in August to begin negotiating its BA's membership in WEIS. (See *Xcel Delays Joining EIM to Examine Options*.)

A CAISO spokesperson said the grid operator was disappointed to learn PSCo had "decided to change course."

"We understand and respect its decision. We remain committed to continued collaboration with PSCo as the Western markets evolve," Anne Gonzales said.

"We're proud that our relationship-based approach and valuable portfolio of services continues to attract utilities looking to modernize and regionalize the way electricity is delivered," SPP CEO Barbara Sugg said. "And we're confident SPP and our WEIS participants will not only benefit from this expansion but will also help these utilities meet their goals of making power delivery more affordable and reliable."

SPP began operating its WEIS market on a contract basis in February 2021, centrally dispatching energy from the region's participating resources every five minutes. It currently comprises six members, including Tri-State Generation & Transmission. CSU will join in August.

Tri-State said in a *release* that PSCo's decision will bring the remaining 20% of its member load into an organized market. Its Eastern Interconnection load became part of the SPP RTO in 2015.

"We welcome additional participants into the SPP WEIS, which increases the efficiency of the market, lowers power costs and further helps to reliably and cost-effectively integrate renewable energy resources," Tri-State CEO Duane Highley said. "Our membership in the SPP WEIS has already greatly benefited our members with lower costs, higher reliability and more efficient dispatch of resources."

Tri-State and CSU are among several WEIS members exploring membership in SPP's *RTO West*. The grid operator is also offering a *Markets+* service for parties that value RTO benefits but aren't ready for membership. It has been a *reliability coordinator* for several Western entities since 2019.

Meanwhile, WEIM is welcoming four new utilities this spring (Avista Utilities, Bonneville Power Authority, Tacoma Public Utilities and Tucson Electric Power). When it adds El Paso Electric, Avangrid and the Western Area Power Authority's Desert Southwest region in 2023, WEIM will cover almost 80% of the Western Interconnection. ■

— Hudson Sangree contributed to this report.

SPP News

MMU Releases Fall Market Reports for SPP, WEIS

Monitor Says TCR Funding Shortfalls a High Priority

By Tom Kleckner

SPP's Market Monitoring Unit is "strongly" recommending that transmission congestion rights' (TCRs) funding shortfall be considered a high-priority item, according to its latest quarterly market *report*.

In the fall report, covering September through November, the MMU said the TCRs' funding percentage varied over the trailing 12 months, ranging between 71 and 115%. It said the underfunding was down by more than $97 million when compared to fall 2020; TCR funding was it its lowest in October at 71%, driven by significant outages not included in the TCR model.

The Monitor said an item has been initiated in SPP's roadmap process to correct the issue. Staff and stakeholders collaborate in this process to identify, educate, prioritize and approve new and existing initiatives for development over the next two to five years.

"Given the magnitude of the issue, we strongly recommend this item be considered as a high-priority item," the MMU said in its report.

The report also found the average gas price at the Panhandle Eastern hub increased to $5.16/MMBtu in October, the highest price since March 2014 outside of last February 2021. The average gas price was up 143% from $1.99/MMBtu the previous fall.

Electricity prices also increased from 2020 to last fall, although at a lower rate. Day-ahead prices rose from an average of $18.21/MWh in 2020 to $33.72/MWh in 2021, an increase of 85%. Real-time prices increased from an average of $17.57/MWh to $31.27/MWh over the same period, up 78%.

The MMU said wind generation was the primary fuel type during the quarter, accounting for 38% of total generation, up 4 percentage points. Coal generation increased from 31% of production to 35%.

The Monitor has also released its latest quarterly *report* for the same period on SPP's Western Energy Imbalance Service (WEIS) market.

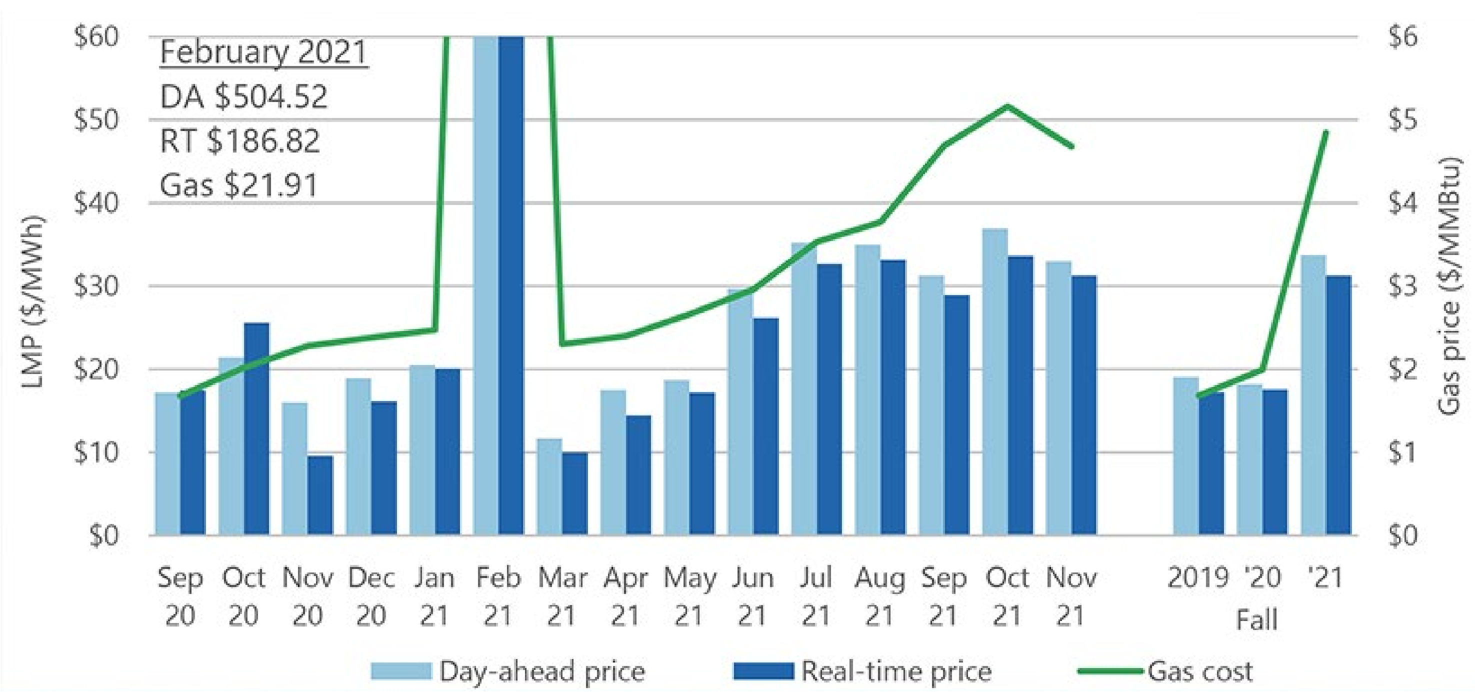
It said the market's average hourly load for September and November was about 2.3 GWh but was down slightly to 2.18 GWh in October. Coal remained the predominate fuel source, the report said, with 66% of total generation in September and decreasing to 62% by November. Hydroelectric generation was the second largest energy source, averaging 22% of total generation in September before trending downward to 17% by November.

The report found that average load and generation energy prices remained consistent with August pricing at slightly over $35/MWh until November, when there was an approximate decrease of 35%.

The market was averaging 1,692 MWh of hourly exports when September began, but they declined to about 1,500 MWh in October and November, the MMU said. Hourly imports averaged 626 MWh in September and increased throughout the quarter to 1,078 MWh by November.

The MMU said the WEIS market continues to struggle with ramp availability and short-term system flexibility, despite an abundance of online capacity. Many dispatchable resources are offered with minimal available dispatchable and/or ramp-able capacity, it said.

Economic limit parameter changes that force additional ramp needs, load forecast changes and changes in net schedule interchange also continue to drive market struggles to supply sufficient ramp. Market participants are also reluctant to offer additional resources because of risks associated with recovering costs when prices drop. ■



Gas prices in SPP's footprint rose to their Integrated Marketplace's highest levels ever ($5.16/MMBtu in October) save for last February. | *SPP*

SPP News

McAdams Stands up for Texas in SPP RSC Debate

SPP CEO Announces Tentative Return-to-office Date; Coal Edged out Wind in 2021

By Tom Kleckner

Texas Public Utility Commissioner Will McAdams restored the Lone Star State's voice last week to SPP's Regional State Committee, arguing against a revision request he said is unfair to his state.

McAdams, taking a break from the PUC's effort to overhaul the ERCOT market following last February's devastating winter storm, beat his fellow regulators to the microphone when it came time to get his comments into the record on the measure being considered.

"I'm sure this will elicit debate or conversations," he said during the RSC's Jan. 24 meeting. "Texas continues to oppose the revision request. … This policy will have the effect of shifting more costs to Texas ratepayers without any foreseeable benefit to those ratepayers in the future."

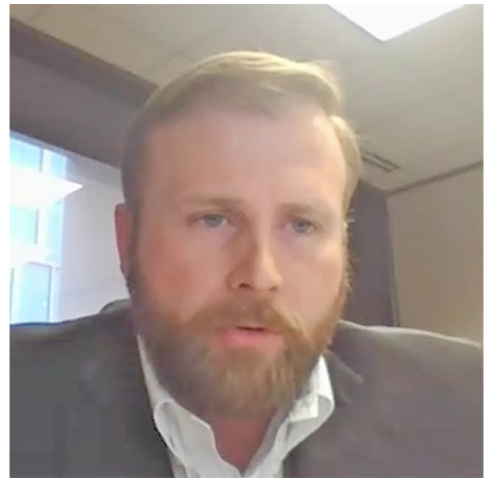
At issue is a proposal (*RR483*) that promises a "surgical approach" to evaluate byway transmission projects in wind-rich zones. It would allow a byway-funded upgrade to be funded through a regionwide allocation after meeting certain criteria under the "narrow review process." Projects eligible for this "narrow and limited process" must have base plan upgrade costs eligible for cost allocation under the SPP tariff.

The measure is intended to address FERC-identified deficiencies in the grid operator's byway facility cost-allocation process. It came just short of endorsement from the Markets and Operations Policy Committee two weeks ago. (See *SPP Board, Regulators to Take up Rejected RRs*.)

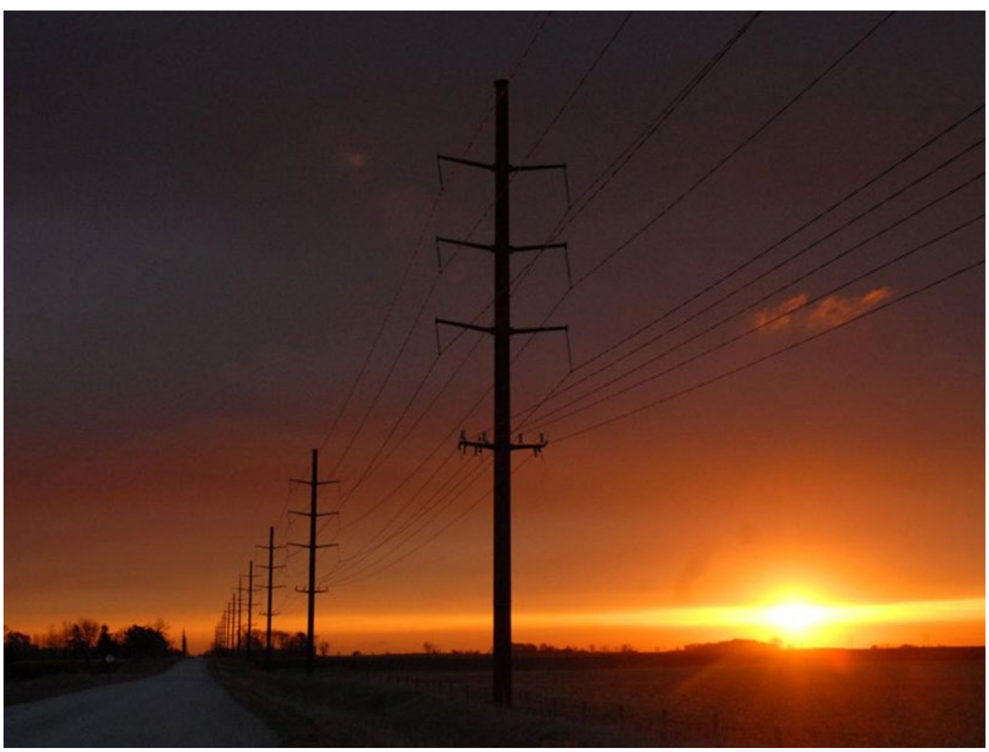
McAdams said the Texas PUC believes the rule change's proposed highway waiver process would allow certain highway projects to be re-evaluated "solely for cost allocation purposes." Echoing other members during the MOPC discussion, he said SPP's regional cost allocation review process offers a remedy for those who think the highway/byway methodology of costs and benefits is unfair.

"No other types of transmission project is afforded this kind of a second chance," McAdams said.

Under SPP's highway/byway mechanism, transmission costs are allocated on a voltage threshold basis. Highway facilities, or those above 300 kV, are allocated 100% on regional, postage-stamp basis. Byway facilities, those between 100 and 300 kV, are allocated on a regional basis (33%) and to the pricing zone (67%) in which the facilities are located. Facilities at or below 100 kV are fully allocated to the zone in which they are located.



Will McAdams, Texas PUC | *SPP*



Cost allocation for transmission upgrades to interconnect renewables promise to remain an issue for SPP members. | *ITC Holdings*

McAdams pointed out that Texas has "rigid statutes" for its non-ERCOT utilities that are not a part of the deregulated market. He asked whether SPP could "paint a roadmap" to where Texas consumers could see a long-term benefit as the state's bountiful renewable energy resources continue to grow.

"In the future, and I know that we're probably going to lose on this … we want to work with the rest of the [RTO]. We want to collaborate," McAdams said. "We would just like to see if we can get to a point where we can see a reasonable benefit in the future for Texas ratepayers, and then we're happy to work on the details."

Joining McAdams in opposing RR483 were regulators from Louisiana, New Mexico and Oklahoma. That was not enough to stop the measure from passing, 7-4. The Board of Directors also approved the revision during its Jan. 25 meeting.

"I think this process is creating an incredibly targeted, narrow waiver process," Kansas Corporation Commissioner Andrew French said. "By design, it's probably not going to apply to a lot of projects. It's going to provide some potential material relief to a few of the most egregious examples where customers in renewable-rich zones or maybe being bur-

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dened by costs but not receiving benefits.

"But as far as cost that might be shifted region-wide? That would be pretty minimal," he said. "As we continue to transition our energy mix to take advantage of some economic energy sources that are that are remote, we do need to make more proactive holistic reforms to cost allocation. We need to continue to look at this because that's ultimately going to be one of the bigger challenges we face."

Four days later during a PUC open meeting, McAdams told his fellow commissioners the proposal "socializes costs for certain generation facilities in their home regions for the interconnection of the facilities."

Noting that SPP's East Texas and West Texas footprints account for about 30% of its load, he said that if RR483 is "reflective of future policy adjustments at SPP, it bears watching."

"I'll be working … to share our concerns so that SPP's Texas ratepayers are not unduly subsidizing projects that are unbeneficial projects where we see no benefit," McAdams said.

The RSC also endorsed *RR476*, which accepts storage resources as transmission assets. The measure defines them as "storage-as-transmission-only assets" and requires them to register as market storage resources in the Integrated Marketplace to account for their injections and withdrawals.

Staff Can Return to Office March 1

SPP has announced an optional return-to-the-office program for staff, effective March 1 ."I'm not a betting person, but if I were, I'm betting we'll be together in April," CEO Barbara Sugg said, referencing the RTO's quarterly governance meetings.

She urged stakeholders not to lose patience with continued restrictions, which have prevented her from meeting publicly in person with the board and key stakeholders. Sugg was named CEO in January 2020, shortly before the pandemic began. (See *SPP Board Taps Barbara Sugg as New CEO*.)

"So far, she has refused to meet with us in person," board Chair Larry Altenbaumer joked. "We hope to change that in the not-so-near future."

Given the lack of travel in 2021, the RSC came in more than 99% under budget last year, spending $3,634 of a planned $498,000. The committee's annual audit, which cost $3,000, accounted for the bulk of the spending.

"A lack of expenditures does not mean a lack of work," said Paul Suskie, the committee's staff secretary.

Coal Edges Wind as No. 1 Fuel

Coal-fired generation slightly outpaced wind in SPP's fuel mix last year, Bruce Rew, senior vice president of operations, said during the quarterly joint stakeholder meeting.

Coal generation accounted for 35.7% of the fuel mix last year, while wind made up 34.6%. Natural gas was 19.9% in the face of increased prices.

Rew said SPP began 2022 with 30.5 GW of available wind generation. It accounted for as much as 70.49% of the RTO's generation Dec. 26, when it produced almost 21 GW of the 27.23 GW of total load.

The Integrated Marketplace now has 281 market participants, with 178 of them classified as financial-only and 103 as asset-owning, Rew said. ■

SPP News

SPP Board of Directors/Members Committee Briefs

Board Approves 2 Tariff Revisions Rejected at MOPC

SPP's Board of Directors last week approved three tariff revision recommendations, two of which fell just short of stakeholder endorsement two weeks ago.

The two revisions requests, RR477 and RR483, were responses to previous tariff revisions that had been rejected at FERC. Both RRs also failed to gain the Market and Operations Policy Committee's endorsement two weeks ago. (See *SPP Board, Regulators to Take up Rejected RRs*.)

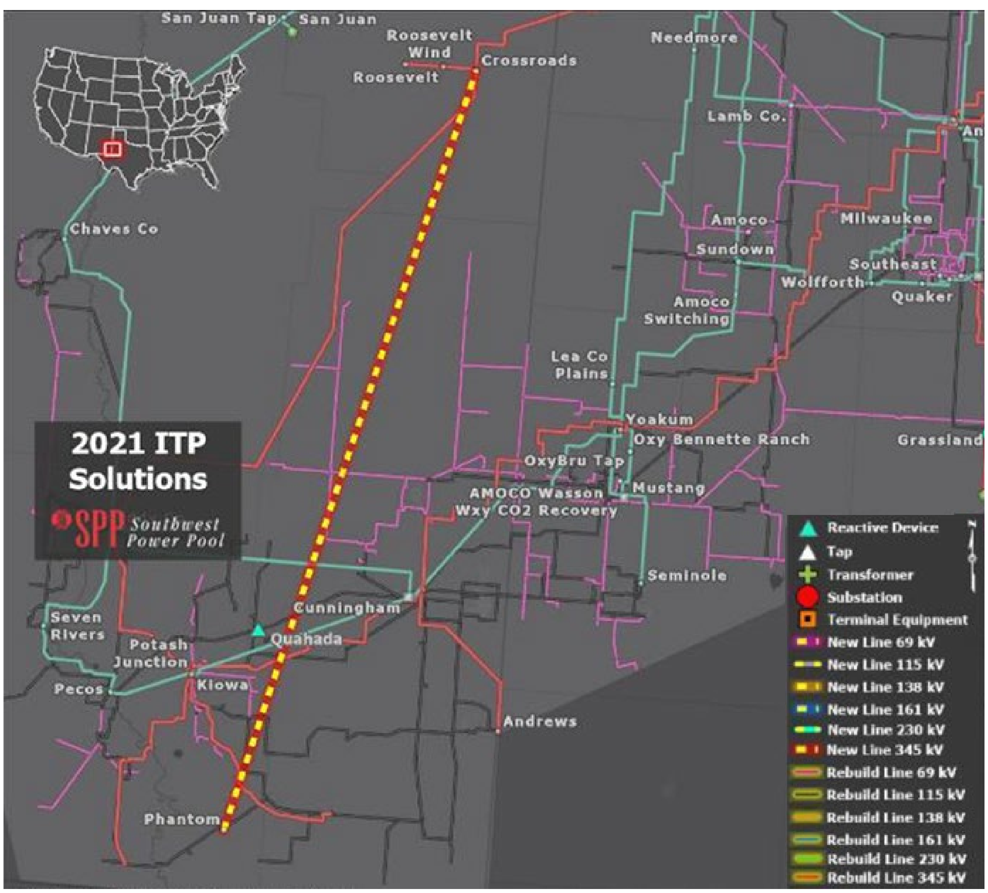
RR477 would establish uniform local planning criteria within each transmission pricing zone. *RR483* would address FERC-identified deficiencies in the grid operator's byway facility cost-allocation process.

The Members Committee approved both measures in advisory votes for the board. RR477 passed 14-7, with an abstention, and was opposed by transmission owners and renewable energy interests. RR483 passed 12-7 with three abstentions, with TOs again in opposition.

ITC Great Plains' Brett Leopold reiterated his company's opposition to RR477, pointing to FERC orders addressing local TO planning in PJM. The orders found that TOs' local planning processes must be open and transparent and allow transmission customers to participate and provide input, he said, while upholding the TOs' right to conduct local planning according to their own established criteria.

RR477 would maintain the original construct of a transmission pricing zone's facilitating TO (FTO) from its rejected application before FERC. However, it would introduce a formal process or ability to influence the FTO's decision-making in establishing zonal planning criteria. It would also establish an avenue to ensure input from the zone's other TOs, customers and stakeholders is considered and set up a two-step voting process.

"We think the solution before us is contrary to some ... cases regarding local planning coming out of PJM," Leopold said. "We're put in a particular position where ... we are not able to retain some autonomy regarding local planning, which we think we're entitled to under the existing FERC precedent. We could be put in a position where we couldn't do needed projects and wouldn't be able to have those costs allocated unless we sponsored them and paid for them ourselves. I think [that is] is the box that we're in."



The proposed Crossroads-Phantom 345-kV project | *SPP*

FERC rejected an earlier proposal in 2020, siding with stakeholders who argued the proposal would give a pricing zone's FTO "unilateral power" and "unduly" benefit them and the zone's largest network load customer. (See *FERC Rejects SPP's Zonal Planning Criteria*.)

SPP has developed another tariff revision (*RR452*) that would create a zonal upgrade study process proving a more expedient review of storm-damage recovery and age and condition projects that need a more urgent in-service date. The revision has been described as a backstop for local planning if a zone can't establish its planning criteria, but Evergy said this is only true if local planning criteria is added to SPP's planning criteria, which has yet to occur.

SPP COO Lanny Nickell said he didn't know when RR452 would be ready for MOPC action and that "it could be something that provides some comfort for the backstop if the zonal planning criteria is not achievable."

Members spent less time debating RR483, which promises a "surgical approach" to evaluate byway transmission projects in wind-rich zones. It would allow a byway-funded upgrade to be funded through a regionwide allocation after meeting certain criteria under the "narrow review process." Projects eligible for this "narrow and limited process" would be required to have base plan upgrade costs eligible for cost allocation under the SPP tariff.

The revision request is a response to FERC's rejection last June of a previous proposal. The commission found it would have given too much discretion to the board in allocating costs and did not include clear standards for making decisions. (See *FERC Rejects SPP's Cost-allocation Waiver Proposal*.)

"A lot of good work went into [RR483], but the criteria that's been established will create issues for large [transmission] zones that don't necessarily have a lot of load. I think it will be nearly impossible for any job in our pricing zone because it's so large," Nebraska Public Power District CEO Tom Kent said. "It will be

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impossible for NPPD to take advantage [of the tariff revision] in our zone. We're going to see our transmission costs continue to go up and continue to be impacted negatively without an ability to take advantage of this surgical exception."

The board also approved *RR476*, which would accept storage resources as transmission assets. The measure defines the assets as "storage-as-transmission-only assets" and would require them to register as market storage resources in the Integrated Marketplace to account for their injections and withdrawals.

All three tariff revisions were among 21 recommendations from the Holistic Integrated Tariff Team in 2019, intended to integrate increased renewable energy, boost reliability and improve transmission planning. (See *SPP Board Approves HITT's Recommendations*.)

Board Approves 2021 ITP, Holds NTCs

The directors followed MOPC's lead two weeks ago in approving the 2021 Integrated Transmission Planning (ITP) *study*, while withdrawing notifications to construct (NTCs) for a 150-mile, 345-kV project in West Texas and a pair of transformer projects in New Mexico. (See *SPP Markets and Operations Policy Committee Briefs: Jan. 10-11, 2022*.)

According to the 10-year assessment, the Crossroads-to-Phantom project would provide a low-resistance, parallel path for delivery of low-cost energy to Southwestern Public Service's SPS South load. The study found that the double-circuit project would provide twice the capacity of a single circuit, while "incrementally" increasing the engineering and construction costs from $330.2 million to $409.9 million, a 23.9% increase.

The project, easily the most expensive in the $1.04 billion portfolio, addresses one of two targeted areas in the 2021 ITP where SPP found voltage-stability issues because of isolated load and above-average load projections. Both targeted regions, the Permian Basin in West Texas and eastern New Mexico, and the Bakken Formation oil fields in North Dakota, are the result of oil and gas growth.

However, load-projection errors, related to how load was allocated to individual substations, were discovered late in the process. Working group stakeholders said the error was found in the 2022 ITP models, too late for staff to do a full impact analysis.

The working groups spent hours trying to resolve the issue in December before recommending the NTCs not be issued.

Ben Trowbridge's (left) and John Cupparo's elections to SPP's Board of Directors adds cybersecurity, IT and utility experience. | *SPP*

Public Service Company of Oklahoma President Peggy Simmons asked whether enough information was provided to MOPC before the decision was made.

"We think the results we came up with, based on the information we had at the time of the study, suggest that the project is the right solution to address the issues," said Antoine Lucas, SPP's engineering vice president. "We did receive information that those assumptions and some of the assumptions SPS believes are material to the project's decision differ from what was studied. That information came along at time where we were too far along in the process where we were able to go back and re-evaluate. That created some uncertainty around the selection of Crossroads-Phantom."

Lucas said staff have agreed to resume discussions with stakeholders "to update their assumptions and see whether a different and better solution can be found to resolve this."

The NTC's withdrawal gives staff further time to evaluate the Crossroads-Phantom project and bring it back to MOPC for its July meeting.

The ITP portfolio includes 28 projects and 380 miles of new 345-kV lines, including Crossroad-Phantom. The projects would solve 185 system needs with a 5.3 to 5.7 benefit-to-cost ratio.

Members Elect 2 New Directors

The membership elected Ben Trowbridge and John Cupparo as directors during a special meeting of members, filling the board's two vacancies. Their three-year terms will expire Dec. 31, 2024.

"Together, they bring a wealth of experience and valuable perspectives in matters related to transmission planning, cybersecurity, finance and other topics that are particularly relevant to our organization right now," CEO Barbara Sugg said in welcoming the board's newest members. "I'm 100% sure you'll be very pleased with their ability to serve SPP as an independent director."

She said Trowbridge fills the board's need for cybersecurity and IT expertise. He was the global leader of Ernst and Young's Cybersecurity as a Service practice, founded the technology advisory firm Alsbridge and has served in other similar positions.

"I'm committed to board service now," Trowbridge told members. "This role means a lot to me. Thank you for allowing me to contribute and make SPP a little better for all the members and stakeholders."

Sugg said SPP was also very specific in searching for candidates with utility experience "who could hit the ground running." As former CEO of Berkshire Hathaway Energy's U.S. Transmission subsidiary and having held leadership positions with PacifiCorp and Koch Industries, Cupparo checked that box.

"As the energy needs of the country become more complex, SPP will play a vital role in achieving its collective membership's objectives," Cupparo said. "My focus will be on leveraging my industry experience to contribute to SPP delivering its mission."

Board Chair Larry Altenbaumer said Director Susan Certoma will be his vice chair. "She has immersed herself in to the nuts and bolts of everything that is SPP," he said. ■

— Tom Kleckner

Company Briefs

Hydro-Quebec Halts Work on Canadian Section of NECEC Tx Line

Provincial utility Hydro-Quebec recently stopped construction on the Canadian section of a transmission corridor that would hook up to the now-stalled $1 billion New England Clean Energy Connect project in Maine.

Hydro-Quebec said it has finished 70% of the right-of-way clearing and access roads, however on Jan. 19, it notified the Canada Energy Regulator that construction was being suspended. The utility said it would secure the construction site for the next few weeks.

The action means that work to forge a new energy connection between the province and New England is on hold. In Maine, NECEC voluntarily stopped work on Nov. 19 at the urging of Gov. Janet Mills following the Nov. 2 ballot initiative in which voters overwhelmingly endorsed a law aimed at killing the project.

More: *Portland Press Herald*

LG Energy Solution, GM to Build $2.1B Battery Factory in US

South Korea's LG Energy Solution announced last week that it plans to spend $2.1 billion with General Motors to build an electric vehicle battery plant in the U.S.

LGES and GM are expected to fund the project equally via Ultium Cells, their U.S.-based battery joint venture. The two companies are building plants in Ohio and Tennessee to manufacture 70 GWh of batteries, which could power about 1 million EVs by 2024.

LGES declined to provide details on the location or production capacity of the new plant.

More: *Reuters*

Vistra to Expand World's Largest Battery Storage Facility

Vistra last week announced that it plans to further expand its Moss Landing Energy Storage Facility in California. It will be the facility's second expansion.

The company has entered into a 15-year resource adequacy agreement with Pacific Gas and Electric Company for a new 350-MW battery system that would complement the existing 400 MW of storage capacity already at the site.

Pending approval from the Public Utilities Commission, Vistra anticipates construction to commence in May and the start of commercial operations prior to June 2023.

More: *Vistra*

Federal Briefs

EPA Acts to Curb Air, Water Pollution in Poor Communities

The EPA last week announced it will take a series of enforcement actions to address air pollution, unsafe drinking water and other problems afflicting minority communities in three Gulf Coast states.

EPA Administrator Michael Regan said the agency will conduct unannounced inspections of chemical plants, refineries and other industrial sites suspected of polluting air and water and causing health problems to nearby residents. It will also install air monitoring equipment in Louisiana's "chemical corridor" to enhance enforcement at chemical and plastics plants between New Orleans and Baton Rouge.

The agency also issued a notice to the city of Jackson, Miss., saying its aging and overwhelmed drinking water system violates the Safe Drinking Water Act and directing the city to outline a plan to "correct the significant deficiencies identified" within 45 days.

More: *The Associated Press*

Mountain Valley Pipeline Loses Permit to Cross Jefferson National Forest

The 4th U.S. Circuit Court of Appeals last week threw out approvals by the U.S. Forest Service and the Bureau of Land Management for the Mountain Valley Pipeline to pass through the Jefferson National Forest.

The three-judge panel said in a written decision that the entities failed to properly predict and prevent erosion and sedimentation caused by building the massive infrastructure project. The court also ruled that the Forest Service failed to comply with its 2012 Planning Rule and prematurely authorized the crossings of some streams in the forest.

The ruling sends the permit back to the Forest Service and BLM for reconsideration.

More: *The Roanoke Times*

White House Mulls Trump-era Solar Tariffs Extension

The White House is considering extending Trump-era tariffs on solar power imports with a handful of tweaks to make it easier for domestic installers to access supplies, sources said.

Former President Donald Trump had imposed a four-year tariff regime on solar imports in 2018, starting at 30% and declining to 15% in the final year. Set to expire on Feb. 6, the White House is considering extending the tariffs on solar panels and cells by four years but would double the number of cells that can be imported before the levies kick in to 5 GW per year. The plan would also exclude bifacial solar panels.

More: *Reuters*

State Briefs

CALIFORNIA

Hayward Power Plant Explosion Blamed on Equipment Design Flaws

Calpine, the owner of the Russell City Energy Center that blew up last May and sent 50-pound pieces of metal flying hundreds of feet, last week blamed design issues and equipment failures — not human error — for the explosion.

Calpine said the inability to detect excess water under pressure at high temperature, a gearbox malfunction, and other design issues attributable to the contractor, caused or contributed to the explosion. However, the company has applied for four applications for confidentiality, including one covering the root cause analysis. It said if it were made public, it could be used to plan an attack on critical infrastructure or reveal trade secrets.

More: *KTVU*

SDG&E, Cleveland National Forest Complete Fire-hardening Project

San Diego Gas & Electric and the Cleveland National Forest last week completed a fire-hardening and safety project, replacing thousands of wooden poles with steel to better protect the grid from the impact of wildfires.

The project included the replacement or undergrounding of equipment to improve the fire resistance of infrastructure throughout 880 square miles in eastern San Diego.

SDG&E said the Cleveland National Forest project is made up of 20 smaller projects, which include a total replacement of 607 miles of new conductor and equipment built to withstand 85 mph winds and high temperatures, 17 new miles of underground distribution lines, and the replacement of more than 2,100 wood poles. With completion of the project, 30% of San Diego's backcountry infrastructure has been fire-hardened to date.

More: *SDG&E*

IOWA

Linn County Approves Coggon Solar Project

The Linn County Board of Supervisors last week voted 2-1 to approve the 100-MW Coggon Solar project.

The approval means that about 750 acres will be rezoned from agricultural to agricultural with a renewable energy overlay that expires after 35 years.

Construction could begin in March and is expected to last less than a year.

More: *The Gazette*

LOUSIANA

PSC to Allow Power Purchases from Firms in Other States

The Public Service Commission last week accepted a $1.5 billion plan for cooperatives to buy power for the next 20 years from utilities in other states and to build a $750 million state-of-the-art generating plant in Iberville Parish.

Under the contract, five of the co-ops will rely on a "portfolio of power" buying different amounts of power from two out-of-state firms that will have to transmit power into Louisiana, three companies using solar power, and a new plant that will be built by Kindle Energy of Princeton, N.J.

Entergy and Cleco Cajun challenged the contract; however, the deal was litigated before Chief Administrative Law Judge Melanie Verzwyvelt, who agreed with the contract.

More: *The New Orleans Advocate*

MICHIGAN

GM to Invest $7B in 4 Facilities

General Motors last week announced that it will invest $7 billion in four facilities and make the state the "hub" of its electric vehicle development and manufacturing.

GM said it will spend $2.6 billion to build a new battery factory in the Lansing area and $4 billion to convert its existing factory in Orion Township to make electric pickups. It will also spend about $500 million to make upgrades to its two existing vehicle assembly plants in Lansing.

The announcement came on the same day the Michigan Strategic Fund approved a series of incentives that total about $824 million to build the battery plant and expand the Orion Assembly plant.

More: *The Detroit Free Press*

MISSISSIPPI

PSC Greenlights Solar Farm

The Public Service Commission last week approved construction for a $90 million, 100-MW solar farm developed by Wildflower Solar.

Northern District Public Service Commissioner Brandon Presley said the power generated will not be sold directly to customers in Mississippi but to MISO. MISO will then sell it to TVA, which will in turn sell it to the Toyota Manufacturing facility in Blue Springs.

More: *The DeSoto Times-Tribune*

NEW MEXICO

Santa Fe County Unveils Plan to Curb Greenhouse Gases

The Santa Fe County Commission last week unanimously voted to adopt a draft plan that creates a path for county government to eliminate its greenhouse gas emissions by 2050.

The initiative is split into six five-year phases and sets reduction benchmarks and outlines steps to further reduce greenhouse gases. The plan mainly focuses on promoting energy efficiency opportunities and improving best practices within four county sectors: buildings and facilities, water and wastewater, transportation and solid waste.

Phase One of the plan, which is underway, seeks to reduce emissions by 25% by 2025.

More: *Santa Fe New Mexican*

NORTH DAKOTA

Industrial Commission Approves Project Tundra's Carbon Storage Plans

The Industrial Commission last week voted unanimously to approve several orders related to Project Tundra, which intends to capture carbon emissions from the Milton R. Young Station coal-fired power plant.

The Minnkota Power Cooperative has worked for years to develop the $1 billion project, which involves injecting carbon dioxide from the plant into rocks deep underground for permanent storage. The co-op proposes to capture and store up to

4 million metric tons of carbon dioxide per year from the plant's exhaust gas and store it more than 4,000 feet deep in the Broom Creek formation.

Minnkota has not yet made a final decision on whether to construct the project, but it expects to decide late this year. If the project moves forward, construction could start near the end of the year and wrap up by 2026.

More: *The Bismarck Tribune*

OHIO

Ex-FirstEnergy Lobbyist Resigns from PUC Nominating Council

Former FirstEnergy lobbyist Michael Koren last week resigned as chairman of the Public Utilities Commission Nominating Council, which leads the state's efforts to pick utility regulators.

Koren cited medical issues as the reason for his resignation.

Koren lobbied for FirstEnergy when House Bill 6, which would subsidize nuclear plants in northern Ohio, was introduced in April 2019. However, Koren later said he knew nothing about the company's bribery scheme.

More: *The Columbus Dispatch*

OKLAHOMA

Commission OKs ONG's $1.357B in Costs from February Cold Snap

The Corporation Commission last week voted 2-1 to approve a financing order linked to the securitization of $1.357 billion in Oklahoma Natural Gas costs arising from the extended cold spell last February.

The measure mandates that ratepayers incur the costs over the next 25 years, equating to a $7.82 monthly raise for a residential customer.

In contrast to last February's $1.357 billion gas costs, ONG spent roughly $222 million on gas purchases during the entire year of 2020, documents show.

More: *Tulsa World*

State Department of Commerce Hires First Automotive Director

The Oklahoma Department of Commerce last week hired Jimmy Cagle as its first automotive director.

In his role with the department's business development team, Cagle will lead the state's efforts to expand its automotive sector and supply chain.

In taking the position, Cagle stepped away from a 37-year career with The Goodyear Tire & Rubber Company.

More: *Tulsa World*

TENNESSEE

Judge Orders TVA to Disclose More Documents on its Offer to Cities

U.S. District Judge Thomas Parker last week issued an order that compelled the Tennessee Valley Authority to hand over documents about how it came up with the contract offer to Memphis.

Parker's order is in response to legal filings from non-profit Protect Our Aquifer and two other environmental nonprofits that have argued that TVA's long-term contracts aren't 20-year deals but never-ending contracts that violate the TVA Act and the National Environmental Policy Act.

Memphis is currently reviewing the bids from about 20 bidders on its power supply.

More: *Memphis Commercial Appeal*

VIRGINIA

Wheeler's Bid for Top Environmental Post Likely Doomed

Democratic senators, who hold a 21-19 majority in the Senate, last week signaled that they have the votes to block Andrew Wheeler, Donald Trump's second head of the EPA, from becoming the state's top environmental official.

Sen. R. Creigh Deeds (D), who is chair of the committee that considers gubernatorial nominees and submits resolutions confirming their appointment, said that he expects Wheeler's nomination will be rejected. Deeds said he and his colleagues read a detailed letter from more than 150 former EPA employees, in which the group detailed much of Wheeler's record at the agency and accused him of having "pursued an extremist approach, methodically weakening EPA's ability to protect public health and the environment, instead favoring polluters."

If a single Democrat supports Wheeler, Republican Lt. Gov. Winsome Earle-Sears would be the tiebreaking vote.

Newly sworn-in Gov. Glenn Youngkin (R) announced earlier this month that he had picked Wheeler for secretary of natural resources.

More: *HuffPost*