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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

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In this week's issue

FERC/Federal News

ICF Report Forecasts Significant Demand Growth This Decade

By James Downing

ICF International forecasts that demand could increase by 9% by 2028, while peak demand could increase by 5% over the same period, according to a *report* it published Sept. 12.

The consulting firm expects that growth to continue, as overall demand will increase by 18% by 2033 and peak demand by 10.7%. The shift to demand growth comes after decades of relatively flat levels in the U.S.

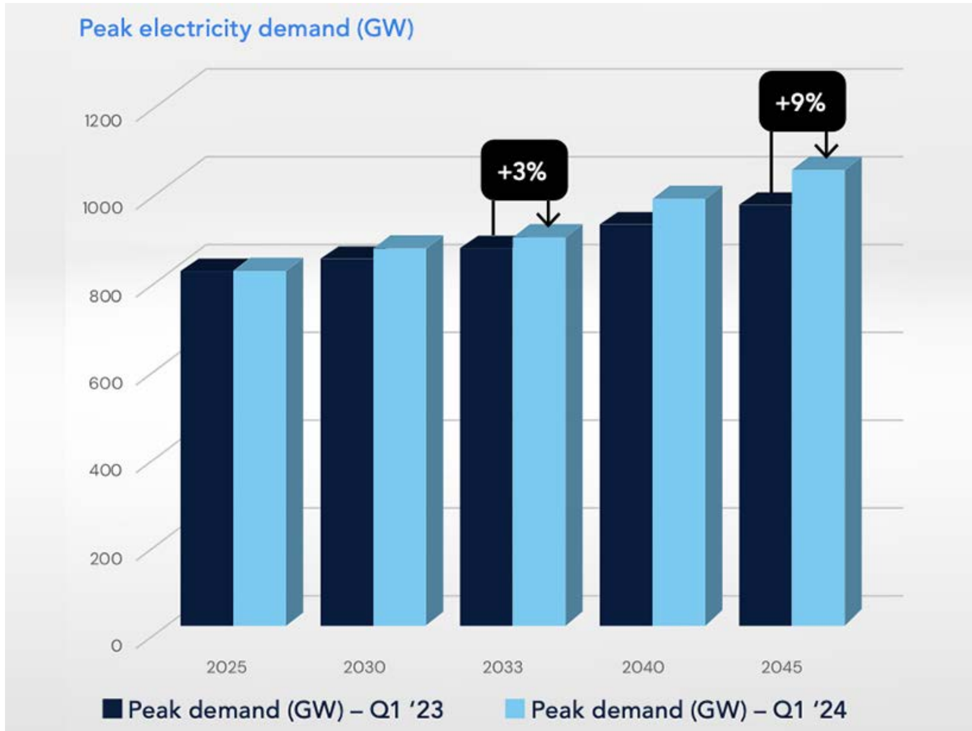
A robust economy, electrification, growth in manufacturing, data centers and cryptomining are all contributing to the rising demand for electricity. Growth will vary by region, with ICF seeing the largest increase overall in the Mid-Atlantic region because of vehicle electrification and data centers, where demand is expected to grow by 68% by 2050, compared to the national average of 57%.

"What makes this stark increase in energy demand, particularly peak demand, so challenging is that it simply wasn't [forecast] in most projections until very recently," the report says. "The latest demand projections are significantly higher than projections made as recently as 2023. The divergence between last year's projections and current projections is broad by 2033 and only continues to grow in the coming decades."

New supply, including utility-scale solar and wind, could help meet the rising demand, but ICF notes that it faces hurdles for that to happen, including the need to upgrade the grid, cutting the time frame of the permitting process and finding suitable locations to build.

The grid is not designed to accommodate major amounts of new generation immediately, with ICF noting that on average, it can handle just 189 MW at once, with upgrades needed to handle additional supply. The Mid-Atlantic, northern New England, parts of the Southeast and the Upper Midwest are particularly constrained in that way, the report says.

And the industry needs to worry about getting that down to the distribution level, with the average amount of such "withdrawal capacity"



| *ICF*

being 153 MW before upgrades are required, with the biggest challenges in areas with high peak demand growth such as Northern Virginia and parts of Texas.

The growing demand could slow progress in the transition to clean energy, as it might force utilities to keep fossil-fueled power plants running longer than otherwise, the report says.

"With enough investment, the U.S. can make major upgrades to the grid and install vast amounts of renewable energy, meeting demand growth while decarbonizing the grid. Americans will likely pay higher utility rates, taxes to pay for federal and state subsidies, or both."

The wholesale prices that many utilities pay for electricity could go up by an average of 19% by 2028, and "much of" that would be passed onto customers, the report says. ERCOT could see even higher price increases of 22% by that year.

The report suggests utilities start engaging in more sophisticated planning that considers the entire system from generators to end-use customers.

"This requires an integrated approach across all asset classes, including generation, transmission, distribution, distributed energy resources, conservation and load management," the report says. "This holistic approach equips utilities to consider long-term investment strategies that enhance grid reliability, resilience and operational efficiency by adding greater flexibility and responsiveness to traditional generation and transmission solutions, like virtual power plants."

Other suggestions include identifying areas with plenty of renewable resources that can be connected to the grid, enhancing the distribution grid, expanding load-management programs, using artificial intelligence to improve planning and grid management, and staying engaged with regulators on the issues. ■

FERC/Federal News

FERC Workshop Examines How to Speed up Interconnection Queues

2-Day Event Held as Demand Growth and Retirements Increase the Need for New Supply

By James Downing

FERC is still working to implement the changes to its generator interconnection rules from Order 2023, but it is also considering further changes, as it held a two-day workshop Sept. 10-11 to gather more input.

Order 2023 made improvements, FERC Chair Willie Phillips said at the start of the event, but it was not meant to be a silver bullet to queues that are still seeing massive interest from new resources and overlapping with widespread demand growth.

"Our country has a severe interconnection queue backlog. We have over 2,000 GW of generation that's waiting in the wings to be connected," Phillips said. "We know right now that the average wait time is over five years for projects to get through the queue. That means that projects that are pretty much ready to go right now have to wait until at least 2029 before there's a single shovel in the ground. I believe, I'm sure you agree, that's unacceptable."

All five of the commissioners participated in or observed the staff-run workshop at different points over the two days.

Commissioner Mark Christie argued that more changes are needed, as many power plants are shutting down while demand is rising.

"Reliability is the overriding goal of interconnection," Christie said. "That means prioritizing those generation resources that can be built quickly and efficiently and that give us the most generation capacity as quickly as possible, at the least cost burden to customers."

The glacial pace of the queues, along with the retirements and rising demand, is contributing to a looming reliability crisis, Christie said. Speeding up new supply can help. One idea that stood out to Christie was from Colorado Public Utilities Commission Chair Eric Blank, who proposed letting state regulators designate which resources would help ensure reliability and giving them preference.

In his written testimony, Blank argued that the current process in Colorado is working well, but a law in the state requires it to join an RTO before 2030, and that could lead to delays. Resources that clear Colorado's competitive resource solicitation are prioritized now, and Blank wants that to continue in an organized market.

"It may be fundamental to Colorado's ability to maintain resource adequacy and cost-effectively comply with our statutory emission-reduction goals by enabling us to select the type of resources we need, where and when we need them," Blank said. "As our transmission utilities seek to join RTOs, we would implore FERC to allow us to continue to prioritize the winning bidders from our competitive resource solicitation process, at least for some transitional period."

CAISO has taken queue reform further than most transmission providers, but its most recent cluster of new projects, Cluster 15, had 541 projects representing 354 GW of new supply, which is so much it just does not make any sense to study it all, said Danielle Osborn Mills, the ISO's principal for infrastructure policy development.

"We now have over three times the amount of capacity that we expect to need to achieve our 2045 objectives," she said.

The issue is not a lack of staffing, or the length of time it would take to study all that excess generation, but rather that developers have proposed so many projects that will never lead to steel in the ground, Mills said.

"The ISO's focus has been really on trying to find ways to increase competition earlier in the process, and to find the best and most ready projects that align best with system need and transmission availability early in the process, so that we're using our study resources to really focus on the projects with the highest likelihood of success," she added.

PJM is currently working through a major backlog of resources and not accepting any new requests until 2026. The RTO is considering a parallel queue to get shovel-ready projects that can help it maintain reliability as its reserve margins are narrowing, said Adrien Ford, director of wholesale market development for Constellation Energy Generation.

"Demand is increasing at an ever-growing rate, and the pace appears to only be getting faster," Ford said. "I believe that RTOs have an obligation to facilitate the reliable and ready resources."

Constellation is the largest nuclear plant owner in the country, most of them in PJM, and they could quickly expand available capacity through uprates. The company has plans to expand two units by 135 MW, but PJM will not be able to even consider its applications for

The first panel from FERC's interconnection workshop: Beth Garza, Arash Ghodsian, John Michael Hagerty, Natasha Henderson, Aubrey Johnson, and David Mindham. | *FERC*

FERC/Federal News

expanded interconnections until 2026, and that delay could be compounded by the units' refueling cycle, which is when such work has to take place.

"If resource adequacy and/or reliability aren't anticipated to be maintained, then the rate cannot be just and reasonable," Ford said. "So, I think it's imperative that action is taken. The expedited reliability process could run in parallel to the existing queue."

FERC has maintained a commitment to open access and ensuring a level, competitive playing field for all resources, said Jason Burwen, vice president of policy and strategy for GridStor. Key precedents such as orders 888 and 2003 are focused on keeping barriers to entry low to allow for more competition to benefit consumers.

"The energy storage industry, of which my company is a member, owes its historic growth to low barriers to market entry that this commission has upheld to date, and open access has been key to enabling capital formation and new market entrants, like my company," Burwen said. "So, when we think about rationing interconnections, this is, first of all, something I just want to call out. This is a second-best, maybe a third-best, solution to the problem at hand. And we should also consider that it is a Band-Aid; that it is probably a temporary fix."

Proactive Planning's Role

SPP is trying out a new approach to queue management, which Burwen and others called the "entry fee approach," and solutions like that could mitigate the underlying issues without sacrificing open access, he added.

The Consolidated Planning Process would mix transmission planning and generator interconnection, co-optimizing the processes and allowing SPP to plan lines that can be paid by both load and new generators, said Natasha Henderson, the RTO's senior director of grid asset utilization.

The CPP involves proactive planning for both new load and supply and then aligning the analysis for both processes, which will enable planners to co-optimize the future grid around both inputs. Then SPP needs to tackle cost allocation so the beneficiaries of those co-optimized lines pay their fair share, Henderson said.

"The concept of the 'entry fee' SPP has in mind is to look for a 20-year transmission plan, determine what that transmission would look like, devise an entry fee based upon that and that entry fee would be known to generation interconnection customers before they would enter the queue," Henderson said.

Developers were in favor of the idea because getting one fee upfront eliminates a key problem they have with the current system: uncertainty. Several developers complained over the two days about frequent restudies upsetting their earlier expectations, and that even when they made it through a balancing authority's queue, they sometimes could be hit with a major bill for upgrades in a neighboring "affected system."

"We need to provide certainty to generators sooner in the process, to allow decisions to be made earlier in the process," said David Mindham, EDP Renewables' director of regulatory and market affairs.

SPP's proposed CPP process would do that, he added. The idea of combining proactive transmission planning with interconnection was supported by many speakers at the conference, with R Street Institute Senior Fellow Beth Garza arguing it would make sense for consumers.

"In too many areas, the interconnection process is being used, instead of comprehensive regional planning, to effectuate network upgrades, and this leads to inefficient outcomes," Garza said. "These inefficient outcomes mean consumers are harmed because, make no mistake, consumers pay, either directly or indirectly, the cost of all transmission. Whether the transmission results from an interconnection process or regional planning process, costs and risks assigned to generators will find their way to consumers, either through higher prices or potentially an inability to procure or purchase the power from their desired sources."

The concept was the subject of a paper that Advanced Energy United and the Solar and Storage Industries Institute commissioned from Brattle Group and Grid Strategies ahead of FERC's workshop. (See *AEU Webinar Highlights Potential Queue Improvements*.)

"The transmission system is not built for new generation resources and load growth," report co-author and Brattle Group Principal John Michael Hagerty said. "That results in a perpetually constrained system that requires complex studies to identify upgrades that are higher costs than they need to be, that does not consider other system needs and is built just in time for new resources."

Connect and Manage

ERCOT avoids the need to study generators' impacts with its "connect and manage" approach to interconnection, in which any impacts new resources cause, like increased congestion, are dealt with in the transmission planning process, said Warren Lasher, president of Lasher Energy Consulting.

"The benefit for the generator is it can move through it at its own pace, and you can see generation that comes online in two and a half, three years," said Lasher, previously ERCOT's senior director of system planning. "The downside is, as you have mentioned, the risk of curtailment. Now, importantly, the risk of curtailment is only shared by renewables at this time, because there are Planning Guide provisions that state that thermal dispatchable generation has to meet a certain amount of dispatchability for resources, specifically for resource adequacy concerns."

ERCOT has not been doing much proactive transmission planning lately, though Lasher said it is working on changes to its economic planning criteria that could lead to improvements.

The Competitive Renewable Energy Zone lines were a pioneering effort in proactive planning and helped Texas shift huge wind resources from points west to its major cities in the eastern part of the state, Lasher said. Now the state's Public Utility Commission is considering transmission development that would shift power the other way as large loads in the form of oil and gas drilling and data centers have located there, in part to take advantage of cheap renewable power that is caught behind constraints.

The FERC equivalent of connect-and-manage is energy resource interconnection service (ERIS), in which generators sign up to be able to sell on the grid with a higher risk of curtailment. There is also network resource integration service (NRIS), which ensures enough deliverability to qualify for capacity auctions in markets that use them. But the difference between ERIS and NRIS can be narrow in some markets.

"ERCOT is not the only transmission provider in the United States treating energy-only service in a significantly less restrictive way," said Tyler Norris, a doctoral student at Duke University's Nicholas School of the Environment, whose research focuses on electric power systems. "At least two other ISOs take a similar approach. Currently, in New York and California, both of those markets have concluded that all, or most thermal power flow constraints for transmission-scale generators can be managed in real time via redispatch, so generally, they are not assigning thermal upgrade costs to

FERC/Federal News

ERIS generators."

Interconnection Queue Automation

Another option FERC considered during the workshop was automation through software.

"I believe automation can yield benefits in three principal areas," said Clayton Barrows, senior researcher at the National Renewable Energy Laboratory: "first, identification of solutions that might not have been apparent to the engineers that traditionally conduct the interconnection studies; second, evaluation of significantly more conditions to improve the robustness of results; and then third, improving the transparency and quality of solutions and the mitigation options that might arise from them."

Pearl Street Technologies is one software firm offering a way to automate the system impact studies in the interconnection process in ways that can speed it up greatly, said its CEO, David Bromberg.

"Even within the studies, there's a whole lot of sub-steps involved, ranging from taking in the data, to building up the power flow models, running the power flow study, identifying the constraints, proposing network upgrades, estimating the costs, running the cost allocation, and then putting all of this in a report that's digestible by interconnection customers," Bromberg said. "So that's a pretty long list. But even that is a simplification, it is a very complex process."

Some of those sub-steps have benefited from automation for years, but Pearl Street offers developers and grid planners ways to automate the entire process, he added. Developers use it to try to pick the best sites for new power plants, while Pearl Street is working with SPP and MISO to automate elements of their interconnection studies.

"SPP has applied automation to our current backlog studies, and we're making our way through those clusters," said Jennifer Swierczek, the RTO's manager of generator interconnection. "By next summer, every request will have a phase 1 and a phase 2 answer, and many more requests will have reached [generator interconnection agreement]. A lot of that is due to the automation that we put in place."

Artificial intelligence has been a hot topic in the electric industry for its projected impact on demand because of the required new data centers, but FERC asked whether the technology could help speed up the queue.

The kind of large language models that consumers are familiar with are not the kind of AI that is capable of speeding up the queue, Bromberg said. Pearl Street's optimization engine can help, but it is just modern computational software, he added.

"We can't tell AI to do even steady-state analysis, let alone transit stability, or if you have a weak grid area, like an electromagnetic transient study, something really complex," said Cody Doll, NextEra Energy senior manager of transmission business management. "AI does, however, seem to do very good job at pattern identification for large datasets, and we've explored potential uses such as parameter verification."

Sifting through large datasets for patterns can be of some use, but it will require new AI technology to transform the interconnection process, he added.

Automation in general has its limits for the complex and nuanced studies required by the interconnection process, said Donnie Bielak, PJM director of interconnection planning.

"You need to have the oversight and the engineering judgment that goes into the scrutiny, and that does take time," he added.

PJM is automating and streamlining where it is possible, but going too far down that road could lead to "poor solution quality" in the interconnection process.

"I like to think of PJM planning as kind of the bouncers at the door," Bielak said. ■

CAISO/West News

CAISO Backtracks on Proposal to Refine Battery BCR

Proposed Solution May Not Reduce BCR Payments Because of Optimization Issue

By Ayla Burnett

CAISO is reconsidering its proposal to address unwarranted bid cost recovery (BCR) payments for storage resources following internal analysis that suggested the proposed solution wouldn't sufficiently address the problem.

The initial proposal would have redefined dispatch unavailable due to battery state of charge (SOC) constraints in the binding interval as "non-optimal energy," which is ineligible for BCR. (See *CAISO Adjusts Timeline for Storage Bid Cost Recovery Initiative*.) But due to the use of multi-interval optimization (MIO), the ISO found the proposal may not significantly reduce BCR payments and would be challenging to implement.

"The proposed solution is based on the assumption that dispatch in the binding interval is optimal," Sergio Dueñas Melendez, CAISO storage sector manager, said at a Sept. 11 Storage Bid Cost Recovery and Default Energy Bids Enhancements workshop. "By optimal, we mean that it's economic. This assumption, however, may not hold true, in general, because of how MIO operates, particularly with regards to energy storage."

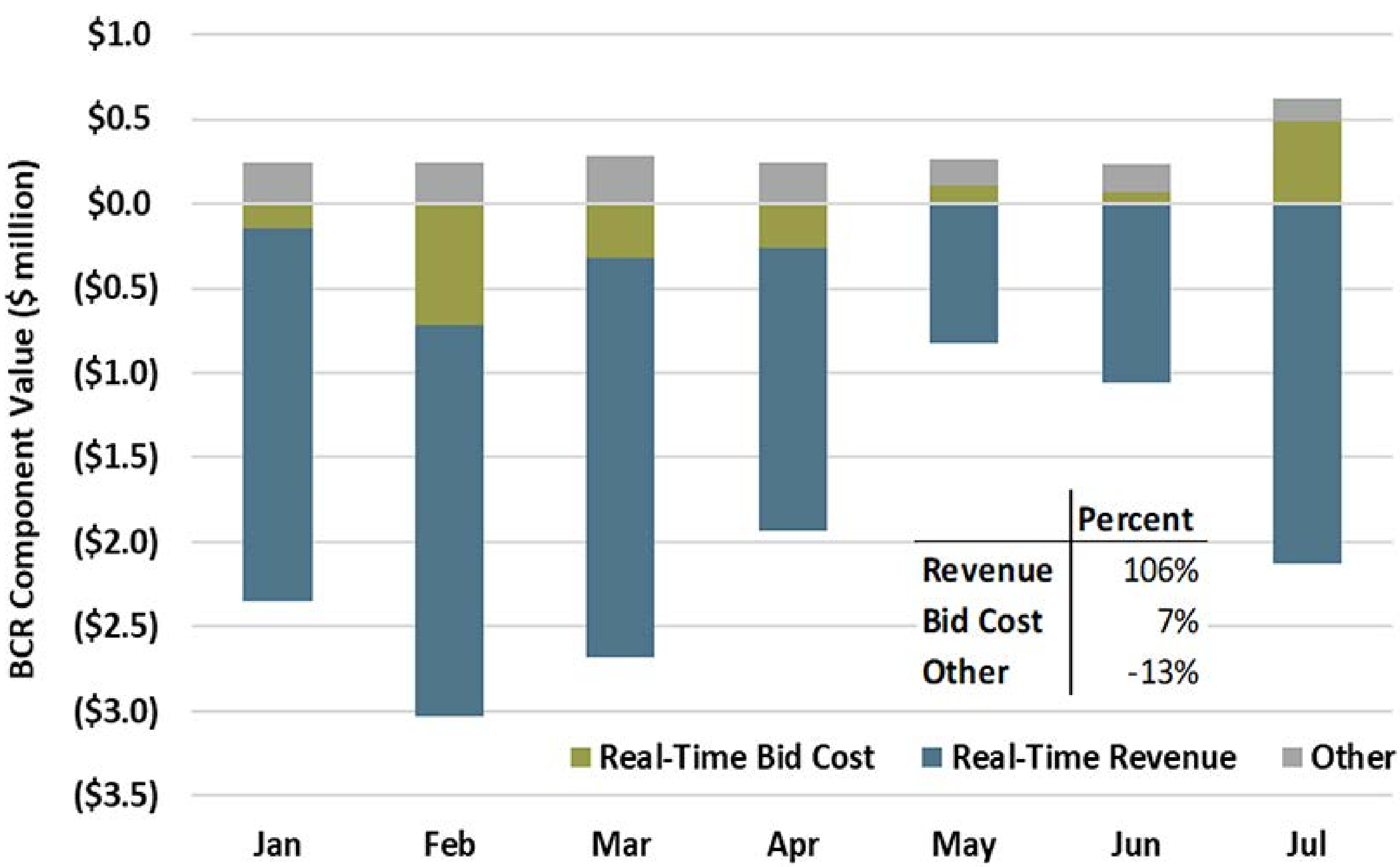
Dueñas Melendez explained that it's "possible for an economic dispatch to occur in the binding interval that would preserve or even increase the state of charge moving forward" in a way that could be repeated across several real-time dispatch runs, "resulting in a situation where the proposed solution would not be triggered and BCR would continue to be allowed to accumulate."

For the proposal to be effective, the ISO would need to modify the solution to consider both binding and advisory intervals. CAISO encountered a similar problem with the ancillary services SOC constraint, Dueñas Melendez said, and while the issue is familiar, it increases the complexity of the solution.

Another concern with the proposed solution was identified regarding market power mitigation, where stakeholders noted that the BCR calculation should not exclude instances in which resources were mitigated in intervals prior to a buy- or sell-back of energy.

"It is important to consider instances in which resources may have had an inadequate state of charge to meet awards of schedules because of mitigation in prior intervals," Dueñas Melendez said.

CAISO's Market Surveillance Committee flagged the issue in prior meetings and recommended further analysis to understand its



BCR payments from January to July 2024 from buy-backs of day-ahead schedules due to insufficient state of charge. | *CAISO* impact on BCR. According to MSC's recommendation, if the analysis showed a material impact, the market could benefit from the ISO developing an exception for mitigation.

Multi-interval Optimization

The ISO provided background on the relationship between MIO and storage BCR. For storage resources, the MIO charges or discharges a storage asset due to projected conditions in the future, "linking solutions over intervals to ensure the asset's limited SOC is utilized when it is most valuable," an ISO presentation said.

MIO charges or discharges a resource to prepare for a future energy award, to avoid hitting a maximum SOC constraint, to adjust for future interval economic conditions stemming from supply, demand or net interchange forecasts, or to rebalance an exceptional dispatch.

"As a result, MIO may dispatch a resource uneconomically in the binding interval due to actions taken by the scheduling coordinator, due to factors that inform the ISO's market optimization, or due to the optimization process itself."

MIO could increase the complexity of developing a solution due to the proposal's assumption that the ISO will be able to identify when a binding interval has an SOC constraint. The problem, Dueñas Melendez said, is that SOC constraints are often not binding in the binding interval, meaning the solution may not be triggered when needed.

Mitigation has 'Minimal Impact'

While stakeholders noted that instances in which resources were mitigated in intervals prior to a buy- or sell-back could merit specific BCR provisions, a presentation from CAISO's Department of Market Monitoring (DMM) suggested otherwise.

For the first half of 2024, real-time BCR for state-of-charge-induced buy- and sell-backs of day-ahead schedules were "primarily driven by negative revenues, not the bid costs," DMM Senior Advisor Roger Avalos said.

Avalos also identified that mitigation of batteries has had minimal impact on dispatch of batteries prior to peak net load hours, even if batteries bid high.

"This indicates that more efficient bidding incentives created under ISO's initial proposal would not have been undermined by local market power mitigation," the presentation reads.

Stakeholders requested additional data that shows not just the impact of mitigation on dispatch, but also its effect on a resource's ability to charge.

"That seems to be where the mitigation is really causing a chokepoint, because it's moving your willingness to pay down lower," said Cathleen Colbert, senior director of Western markets policy at Vistra.

To better understand the complexity of the issue, other stakeholders echoed Colbert's request.

"It would be helpful to see a more distinct breakdown between reductions of discharge versus reductions of charging for purposes of mitigation, just to see if there's any effective patterns that might be found there," said Josh Arnold, senior market and operations analyst at Customized Energy Solutions. "Some additional clarity would be very welcome."

The draft final proposal is slated for Sept. 30. ■

CAISO/West News

Consumer Response Saved Alberta Grid During Jan. 2024 Cold Snap

New Gas-fired Plants Leave AESO Better Prepared for Upcoming Winter

By Elaine Goodman

An emergency alert urging the public to conserve energy helped the Alberta Electric System Operator narrowly avert rolling blackouts during January's extreme cold snap, an AESO representative said during a WECC webinar.

The Alberta Emergency Management Agency sent the alert to cell phones and televisions at 6:44 p.m. on Saturday, Jan. 13, asking residents to immediately limit their electricity use to essential needs only.

"Extreme cold resulting in high power demand has placed the Alberta grid at a high risk of rotating power outages this evening," the message said.

Within three minutes, load dropped by 170 MW, followed by an additional 100 MW after 10 minutes, according to Lane Belsher, AESO's director of grid and market operations. Load continued to fall as "people were shaming their neighbors into shutting their lights off," he said.

"It amazed me," Belsher said. "We did not end up shedding any firm load."

Belsher discussed the January cold snap during a Sept. 10 WECC *webinar* focused on winter-weather readiness.

The Canadian province had been enjoying mild, fall-like weather in early January before temperatures dropped below minus 40 degrees Fahrenheit in some locations.

The system hit an all-time winter peak of 12,384 MW on Jan. 11. Strong winds — and accompanying wind generation — that accompanied the falling temperatures helped the system meet demand on that day, Belsher said.

But conditions grew more challenging as the wind died down. AESO issued an energy emergency alert 3 on four days in a row, from Jan. 12-15.

The situation was especially dire as AESO neared its peak demand Jan. 13. Solar power is mostly gone by the peak, Belsher said, and AESO is heavily dependent on gas generation during winter.

But right at the system peak, generation from a large thermal unit dropped from 450 MW to about 160 MW, he said. AESO decided to use 190 MW of battery storage that it had been keeping "in our back pocket," Belsher said. But the extreme temperatures meant the batteries would work for only about an hour rather than the expected two hours.

Similarly, about 150 MW was available through Western Power Pool reserve sharing, but only for about an hour.

A WECC winter-weather readiness webinar featured a discussion of the Alberta Electric System Operator's response to the severe cold snap of January 2024. AESO is heavily dependent on gas generation during cold weather. | *Electricity Canada*

Belsher talked to Alberta government officials, who deemed the situation to be life-threatening. The emergency alert was sent to the public, and blackouts were avoided.

Alert Used During Calif. Heat Wave

A public alert is a tool that has also been used successfully to avoid rolling blackouts in California — albeit during a heat wave rather than a cold snap.

At 5:45 p.m. on Sept. 6, 2022, the Governor's Office of Emergency Services sent a message to 27 million cell phones, accompanied by a series of shrieking tones.

The message, sent during a 10-day, record-breaking heat wave, said: "Conserve energy now to protect public health and safety. Extreme heat is straining the state energy grid. Power interruptions may occur unless you take action."

CAISO saw demand drop by 2,385 MW, to 48 GW, within 20 minutes of the alert, enough to avoid blackouts. (See *CAISO Reports on Summer Heat Wave Performance*.)

At AESO, another issue during the January cold snap was the price cap for imports. Belsher said the Mid-C spot price in the Northwest the evening of Jan. 13 was about $1,300 CAD; AESO's price cap is $1,000.

Belsher noted that the system completed its phaseout of coal this year. A gas generator was off temporarily during the cold snap due to a frozen gas valve.

Two additional combined-cycle gas units were commissioned this year but weren't available in January.

"It would have been nice to have them, but I think we're in better shape for this winter coming forward," Belsher said.

Another speaker during the WECC webinar was David Lemmons, co-founder of Greybeard Compliance Services. He discussed a new NERC standard, *EOP-012-2*, which requires power plants to have a winter-readiness plan.

Lemmons said plant operators should consider whether their gas delivery path is protected from the weather, and if start-up will take longer when it's cold outside.

Other advice included checking for broken or missing windows and making sure windows are closed before cold weather arrives. ■

CAISO/West News

BLM OKs NV Energy's Greenlink West Line

Agency Also Advances Greenlink North, Approves Massive Nev. Solar Farm

By Robert Mullin

The U.S. Bureau of Land Management on Sept. 9 issued a *record of decision* approving NV Energy's Greenlink West, a 470-mile transmission line that will connect Las Vegas with the northern part of Nevada and be capable of transmitting up to 4,000 MW of energy.

The project will consist of a 350-mile, 525-kV segment from Las Vegas to Yerington, along with two 345-kV lines running from Yerington into the Reno/Sparks area. Construction of the line is expected to begin in the first quarter of 2025 with an in-service date targeted for May 2027.

BLM also opened a comment period for a proposed draft resource management plan amendment and environmental impact statement for the Greenlink North project, a 210-mile east-west line designed to connect Greenlink West with NV Energy's existing One Nevada Line running along the eastern part of the state.

NV Energy considers the Greenlink projects to be "vital" to tapping the state's renewable resources and maintaining grid reliability in the face of growing load, an NV Energy executive said in the utility's most recent integrated resource plan, filed with the Public Utilities Commission of Nevada in May.

But the IRP also revealed the rising costs for the projects, now estimated at $4.239 billion, a 70.6% increase from initial estimates made in 2020. NV Energy attributed $124 million of the increase to the BLM's requirement that the utility use an additional 160 miles of H-frame structures to mitigate risk to desert tortoise and sage grouse habitat. Other environmental mitigations added $30 million to project costs. (See *NV Energy IRP Describes $1.76B Cost Jump for Greenlink Projects*.)

Given Nevada's central position between the resource-rich interior West and more populous West Coast, the Greenlink project also likely will play a key role in transferring energy among various regions participating in CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM). In May, NV Energy said it would choose to join EDAM over SPP's Markets+, a major victory for CAISO in the competition between the two Western day-ahead markets. (See *NV Energy Confirms Intent to Join CAISO's EDAM*.)

The U.S. Bureau of Land Management on Sept. 9 issued a record of decision that greenlights construction of NV Energy's Greenlink West transmission line and opens a comment period for the Greenlink North portion of the project. | *NV Energy*

Massive Solar-plus-battery Project Approved

The BLM on Sept. 9 also approved Arevia Power's $2.3 billion Libra Solar Project, which will be built across 5,778 acres of public land in Mineral County, Nevada. It will be one of the largest solar-plus-battery storage projects in the U.S., consisting of 700 MW of solar and 700 MW/2.8 GWh of energy storage capacity. NV Energy will be the off-taker for the project's output.

"From building large scale transmission lines to solar power generating facilities, the Interior Department and our team at the Bureau of Land Management are leading the way in the development of reliable, clean energy across the West," acting Deputy Secretary of the Interior Laura Daniel-Davis said during a Sept. 10 event in Las Vegas to announce the developments. "The infrastructure projects we are advancing today in Nevada are helping meet President Biden's ambitious renewable energy goals while making communities more energy resilient and creating good-paying jobs in the clean energy economy." ■

CAISO/West News

Clean Energy Buyers Push Passage of New Calif. Reliability Law

AB 2368 Requires CPUC to Use 1-In-10 LOLE or Equivalent When Setting RA Standard

By Ayla Burnett

Large buyers of clean energy were the key backers of a California bill passed last month to strengthen the state's reliability planning.

The state's reliability planning has grown more challenging given the increased frequency of extreme weather events, higher temperatures and greater load variability — creating the need for better planning to offset uncertainty and keep the lights on.

Sponsored by the Clean Energy Buyers Association (CEBA), *Assembly Bill 2368* seeks to address that need, requiring the California Public Utilities Commission to adopt a 1-in-10 loss of load expectation (LOLE) — or a similarly robust planning standard — when setting resource adequacy requirements.

The bill also directs the commission to develop a "mid-term reliability assessment" using probabilistic modeling that looks two to five years into the future to better anticipate potential procurement shortfalls and resulting reliability issues.

Additionally, it requires increased information-sharing between the CPUC and CAISO to enable the ISO to conduct its own reliability modeling and ensure it can meet its own regulatory obligations.

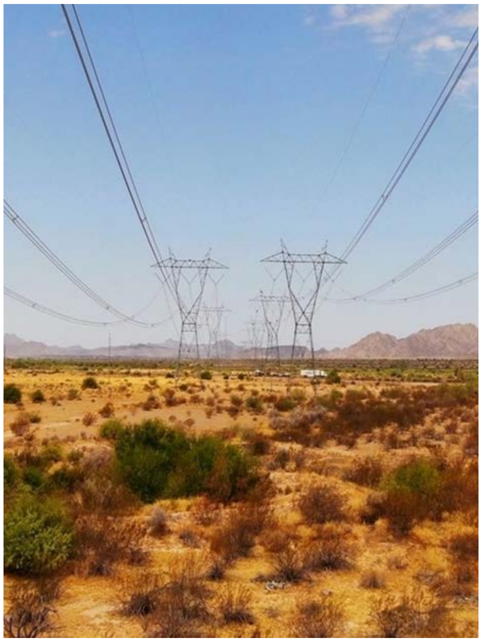
While the 1-in-10 metric is a widely used planning standard, the legislation marks the first time it has been written into California law.

According to Heidi Ratz, CEBA deputy director of market and policy innovation, FERC views RA as state jurisdictional, though most planning standards are set by regional balancing authorities. Other entities, such as the Western Resource Adequacy Program, have formalized a 1-in-10 LOLE target, and agencies such as the CPUC and the California Energy Commission *support it* for California.

'Right Amount of Resources'

Proponents of the bill say that enshrining a stricter LOLE standard into law will modernize the state's planning framework and improve the planning and procurement process.

"Grid planners in California have acknowledged the challenges to electricity resource adequacy and grid reliability within the state, and CEBA sponsored this legislation to tackle some fundamental energy planning issues,"



The Clean Energy Buyers Association pushed for AB 2368, which would improve reliability planning, to pass | *MMR Group*

Ratz said in a CEBA *press release*. "As our grid faces unprecedented pressures, including extreme weather and demand growth, California leaders must have a sense of urgency in implementing sound resource adequacy planning and procurement processes."

Ratz further emphasized that the bill will help grid planners increase trust in their RA programs and decrease the need to rely on the state's *Strategic Reliability Reserve*.

"As planning agencies move towards procuring the right amount of resources well in advance, we will see fewer outages, 'near misses' and emergency procurements, meaning reliability will hopefully be noticeably improved," Ratz told *RTO Insider* in an email. "We'll also see a decrease in scarcity which leads to lower transaction costs in the real-time energy market and more functional capacity markets that send better price signals to market participants. Ensuring the right resources show up in the energy market during times of grid stress is the primary way to improve reliability."

CAISO stakeholders have been calling for improved LOLE modeling for some time. In June, Gridwell Consulting asked the ISO to take a bigger role in reliability planning and conduct probabilistic LOLE modeling to better understand the aggregate impact of the changing climate on grid conditions. (See *Stakeholders Call on CAISO to Take Larger Role in Reliability Planning*.)

Gridwell CEO Carrie Bentley emphasized the need for better planning by citing data showing that, between 2017 and 2023, load variability was significant enough to cause load forecasts to deviate from actual loads by several thousand more megawatts than historically normal.

Gridwell joined CEBA in support of the legislation, also emphasizing its potential to lower costs.

"This will improve reliability and in the long run lower costs compared to the system in place today that caused California's reliability levels to vary widely over time," Bentley said.

In 2014, the CPUC opened a proceeding to address mid-term reliability that resulted in recommendations that were never adopted. Had they been adopted, it is likely that much of 2020's capacity shortfalls could have been avoided, Ratz said. The lack of a stricter planning and modeling framework created the conditions for the events in 2020 and continues to have impacts on cost and reliability.

"Since the outages of 2020, California has issued four last-minute, ad-hoc emergency procurement orders; each ordered the LSEs to sign contracts with new resources that can come online as quickly as possible," Ratz said. "CPUC did conduct limited modeling (reliability analyses) before adopting these decisions that demonstrated the urgent need for additional generation capacity to come online in the mid-term. Combined with the strategic reserve, these were some of the most expensive procurements in California's history, and these expensive electricity emergencies have material impact on customers' operations in the state."

CEBA is urging Gov. Gavin Newsom to expedite signing the bill, which has received support from other agencies such as the Environmental Defense Fund, Pacific Gas and Electric, International Brotherhood of Electrical Workers and more.

AB 2368 is the first reliability-focused bill sponsored by CEBA, signaling the importance of reliability to the group's members.

"The planning improvements in the bill are critical to California's ability to provide energy customers with low-cost, reliable, clean power," Ratz said. ■

CAISO/West News

CPUC Sets New Energization Timelines for Calif. IOUs

New Rules Could Reduce Timelines by up to 49%, Improve Accountability

By Ayla Burnett

The California Public Utilities Commission on Sept. 12 approved rules requiring the state's three large investor-owned utilities to meet stricter timelines and targets for connecting electricity customers to the grid.

"Electricity is the fuel of our future, and the utility grid must be ready to meet customer needs for energization without delay," said CPUC President Alice Reynolds. "This decision moves us forward by improving oversight, transparency and accountability to serve the needs of EV charging stations, new housing developments, building electrification and other customer requests for service."

The timelines are meant to expedite the process for new and upgraded electrical services, enhance utility accountability, offer greater transparency for customers and support California's climate goals, according to a CPUC *press release*.

The new rules apply to Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric.

If targets are met by IOUs, maximum timelines for grid connections could be reduced up to 49% compared with current operations, increasing the speed of energization for projects reliant on electricity connections, the press release notes.

The decision implements *Senate Bill 410*, known as the Powering Up Californians Act, and *Assembly Bill 50*, both of which direct the CPUC to define reasonable average and maximum energization timelines for new or upgraded electrical loads, publish biannual reports, establish a process for reporting delays and adopt remedial actions if they are exceeded.

SB 410 addresses the time necessary to complete customer energization requests, including upgrades to the distribution system and the extension of new electric service. It requires the commission to, no later than Sept. 30, 2024, establish the average and maximum time an IOU should take to complete upgrades or establish new service, as well as a method for customers to report instances when those energization targets are met.

"The bill recognizes that to meet California's decarbonization goals, new customers must be promptly connected to the electrical distribution system, and existing customers must have their service level upgraded in a timely manner," the decision said.

AB 50 requires the CPUC to determine the criteria for what is considered timely energization for electric customers. It also requires "each large electrical corporation that energized less than 35% of customers with completed applications exceeding 12 months in duration by Jan. 31, 2023, to submit a report to the commission, as specified, on or before Dec. 1, 2024, demonstrating that the large electrical corporation has energized 80% of customers with applications deemed complete as of Jan. 31, 2023, as specified."

The CPUC's decision *sets a target* for an average timeline of 182 days and a maximum timeline of 357 days for energization of the commission's Rule 15 projects, which involve distribution line extensions for IOUs. For Rule 16, which refers to service line extensions typically associated with a single customer instead of multiple customers, the target sets an average timeline of 182 days and a maximum of 335 days for energization.

Rule 29, which refers to EV infrastructure, shares the same timelines, and several other energization timing targets are set for application decisions, circuit or substation upgrades, and main panel upgrades.

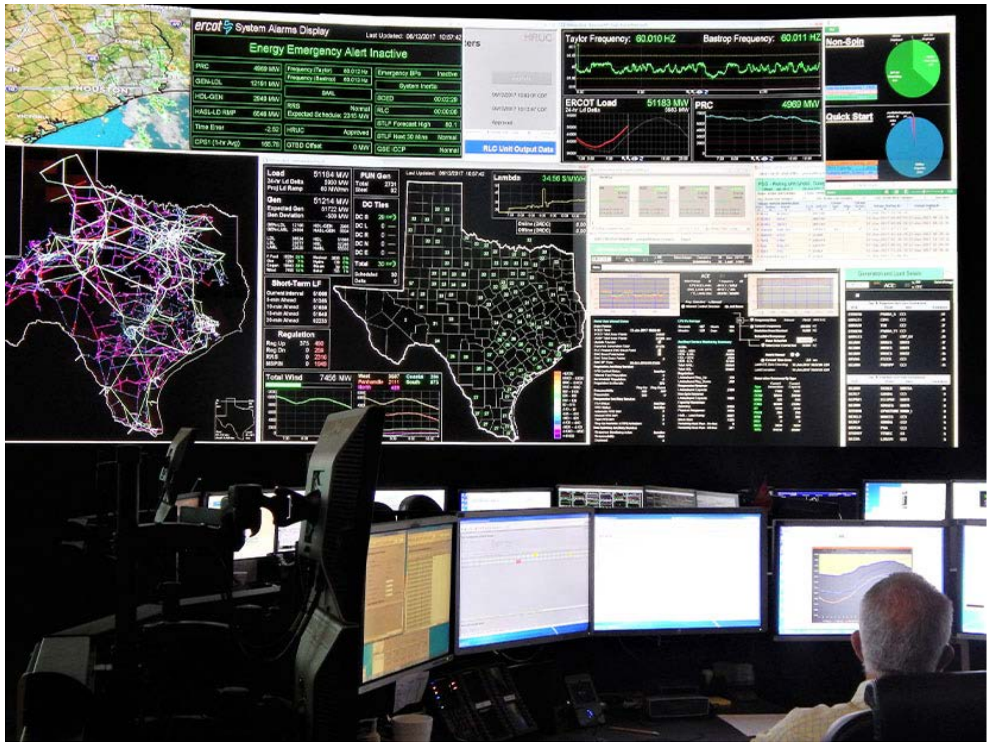
"As we move further along in the energy transition, we must ensure that all customers have timely access to electric service," said CPUC Commissioner Darcie Houck. "This decision is a positive step forward in helping to meet California's ambitious clean energy goals while appropriately balancing customer need and affordability with utility capabilities." ■

The California Public Utilities Commission in San Francisco | *© RTO Insider LLC*

ERCOT News

ERCOT Sets Go-live Date for RTC, ESR Project

By Tom Kleckner



Real-time co-optimization will add millions in savings to the ERCOT market. | *© RTO Insider LLC*

ERCOT has set a target go-live date for its real-time co-optimization project, which is expected to add millions in savings to its market.

The Texas grid operator said Sept. 13 that it has set a Dec. 5, 2025, goal for the market change, about six months ahead of its original mid-2026 timeline.

Real-time co-optimization (RTC) is used by most other grid operators in North America. The market tool procures energy and ancillary services every five minutes, automating many processes that currently are managed manually. ERCOT currently procures ancillary services in the day-ahead market and typically does not move them between resources in the real-time market.

CEO Pablo Vegas said RTC's implementation is "the most significant market enhancement" to ERCOT's nodal design since its inception in 2010.

"The target go-live date represents an important milestone in ERCOT's confidence for planning and tracking the completion of the RTC project for a more dynamic and efficient wholesale power market," he said in a *statement*.

The ISO's Independent Market Monitor in 2018 released a *report* that evaluated RTC's effect on the market. Using 2017 as its simulated operating year, it found a $1.6 billion reduction in total energy costs; an $11.6 million reduction in production costs to serve load; a $257 million reduction in congestion costs; a $155 million reduction in AS costs; and reliability improvements due to a reduced overloading of transmission constraints and a decrease in regulation up.

Staff and stakeholders have been working on the RTC project since 2019, when the Public Utility Commission directed ERCOT to add the mechanism after the commission assessed its costs and benefits. (See "Real-time Co-optimization Go-live Date Could be Accelerated," *ERCOT Technical Advisory Committee Briefs: Aug. 28, 2024*.)

The project has been expanded to address the growth of energy storage resources in ERCOT. Texas began 2024 with about 5,000 MW of energy storage online, second only to California. It is expected to add more than 6,000 MW this year, according to the *U.S. Energy Information Administration*.

System testing will begin early next year. Market trials are planned to begin in May and run through November. ■

ERCOT News

ERCOT Cybersecurity Monitor Shares Best Practices

By Tom Kleckner

Speaking to ERCOT stakeholders, Chuck Bondurant, the Texas Public Utility Commission's director of critical infrastructure security and risk management (CISRM), urged his listeners to treat the ISO's grid as a special jewel.

"You know, we brag that we're our own grid," he said Sept. 10 during a Talk with Texas RE webinar. "So, let's protect it that way."

As the commission's security lead, Bondurant helped set up ERCOT's *Cybersecurity Monitor Program*, a voluntary outreach effort to involve the state's utilities in sharing best cyber-defense practices. The program, focused on physical security issues, kicked off what he said was a "massive" recruitment effort in 2020; it now numbers 65 participants.

The monitoring program was created by *state legislation* requiring the PUC and ERCOT to "foster a more collaborative, strategic approach identifying cybersecurity issues" and improve security measures in electric infrastructure. The cybersecurity monitor is responsible for managing the outreach, communicating emerging threats and best business practices, reviewing cybersecurity self-assessments, researching and developing best business practices for cybersecurity, and reporting "monitored utilities'" preparedness.

The program is free for utilities in the ERCOT region but costs $4,322 for those in the MISO South, SPP and WECC portions of Texas. It is managed by Paragon Systems, a Houston-based security guard service.

Quarterly meetings form the program's backbone. Bondurant said the meetings are open to utilities that "may be on the fence" about joining the program to learn more about the program.

"This is what we originally envisioned. ... This is a chance for utilities to have a safe space where they could dialogue," he said. "This is just another forum, another opportunity for utilities to kind of get together and discuss, 'Hey, these are the things that that concern us.'"

Stressing the cybersecurity monitor is not an auditor, Bondurant said, "We're here to come alongside the utilities and get a better understanding of what we are and where we're at, cyber security-wise across the state."

"Texas is a huge space, and it's pretty hard to be able to touch every single one of the utilities within the state. This program kind of helps us get an overall, generalized view of what we look like across the board, whether it's municipal utilities, co-ops or investor-owned utilities," he added.

Recent topics have included unmanned aerial systems, which include drones.

"That is a huge, huge topic that's not just being talked about here in Texas," Bondurant said. "Some of the discussion is, 'How do we help utilities?' [Utilities] are kind of hamstrung by federal requirements on what you can and can't do in defense of your systems in concern with unmanned aerial systems. We're discussing this, seeing what can be done legislatively to give [utilities] additional tools [to] combat this."

The program will hold a Critical Infrastructure Cybersecurity Summit on Oct. 9-10 on the University of Texas at San Antonio campus. It will feature speakers from the U.S. Department of Energy, the federal Cybersecurity and Infrastructure Security Agency, NERC and other security professionals. ■

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ERCOT News

EHV Tx Lines Coming into Focus for ERCOT

Texas PUC, Grid Operator See Need to Meet Growing Permian Demand

By Tom Kleckner

Texas regulators are narrowing in on a reliability plan for what one said will be a "monumental infrastructure buildout" and could include 765-kV transmission to meet growing petroleum and data center demand in West Texas.

Native West Texan Lori Cobos is the commissioner behind the quote and leader of the Public Utility Commission's effort to add transmission infrastructure supporting the oil-rich Permian Basin. She *proposed* during the PUC's Sept. 12 open meeting three regulatory proceedings to secure the reliability plan's approval (*55718*).

Cobos recommended approving local projects required to serve the Permian through 2038; authorizing transmission service providers (TSPs) to begin preparing applications for five import paths into the region; and creating a monitor to oversee the plan's completion.

The reliability plan builds on a recent *ERCOT report* that projected oil and gas load peaking at nearly 15 GW by 2038 and an additional 12 GW of data center and other non-petroleum load by 2030. The total would come to about a third of the system's current summer peak. Based on those projections, ERCOT said building the transmission facilities to meet that load could cost up to $15.32 billion. (See *SPP Considering 765-kV Solution for Permian Basin*.)

The grid operator's staff studied two case years, 2030 and 2038, and grouped projects as either local or import paths. The local projects are independent of the study years, while the import paths consist of 345-, 500- or 765-kV options.

ERCOT filed an *addendum* to the plan identifying a new endpoint for one of the import paths. It said the new endpoint would "better align" with the PUC's recommendation allowing TSPs to begin their preparatory work while the commission decides on voltage levels.

Commissioner Jimmy Glotfelty, who has almost a decade of experience building HVDC lines, said if he had a magic wand, he would push for 765-kV lines over 345 kV.

"Let's just do the 765 and get it over with, but I recognize that we're not all there, so I think the path forward that you've laid out in your memo is right," he told Cobos and the other commissioners. "The only one question that I have is the default back to 345. I would almost like that reversed, but that's not something we need to solve today."

ERCOT's Kristi Hobbs briefs the PUC on the grid operator's extra-high-voltage transmission plans. | *Admin Monitor*

PUC staff recommends the commission adopt the 2038 case's import path, noting 90% of the forecasting load for that year also is present in the 2030 case year. They also suggested waiting until mid-March to approve the import paths' voltage levels.

Representatives from the petroleum industry agreed with the approach, saying earlier is better. ERCOT also said it could work with any of the PUC's recommendations.

Citing concerns from the region over the need for certainty on the plan, the grid operator's Kristi Hobbs, vice president of system planning and weatherization, said the TSPs "desire to start working on the [certificates of convenience and necessity] that take a lot of time to go through the contracting periods before they can actually file at the commission, so that allows that work to start now."

ERCOT is hosting a *workshop* at its Austin headquarters Sept. 18 on extra-high-voltage (EHV) lines. Vendors in the space will share information on supply chains, timelines, costs, construction timelines and operational characteristics of EHV lines. The grid operator also has added an EHV transmission plan to its annual Regional Transmission Plan, which will be filed in December.

The Permian reliability plan is a result of *legislation* passed last year and is due Jan. 30, 2025. The PUC will consider the issue again during its Sept. 26 open meeting.

"I think we'll see a lot of economic development as a result of this. I think it's going to pay for itself over time because of the amount of economic development that's going to come as a result of that," Glotfelty said. "765 is used in the U.S. It's used in Canada, it's used in Brazil, Venezuela, Russia, South Africa, South Korea and India. It's been used since the '60s, so this isn't a new technology. It's just new to us at ERCOT."

ERCOT News

CenterPoint Case Delayed

The commissioners extended CenterPoint Energy's appeal of a recent court ruling rejecting its request to withdraw its rate case, saying they want to hear from Houston residents first (*56211*).

The PUC is hosting a workshop Oct. 5 in Houston to give CenterPoint customers and others a chance to weigh in on CenterPoint's slow restoration of power after July's Hurricane Beryl. It agreed to take up the matter during its Oct. 24 open meeting.

"I think it's important that before we make any decision, we go through that process and have our hearing in Houston," Gleeson said.

The State Office of Administrative Hearings (SOAH) in August *rejected* CenterPoint's request to withdraw its rate increase to recover $6 billion of investments made since its last rate proceeding in 2019 and expand its return on equity. SOAH said the withdrawal would conflict with state law requiring investor-owned utilities in ERCOT to file a comprehensive rate review within 48 months of their most recent rate proceeding. (See *CenterPoint Energy Still in Eye of the Storm*.)

The commission has been directed to file a report on CenterPoint's restoration efforts with Gov. Greg Abbott by December. It has received more than 16,000 responses to a public questionnaire and an additional 120 responsive filings from utilities, cities and trade associations.

Engie-ERCOT Dispute Deferred

The commission heard oral arguments but took no action on a two-year dispute between Engie North America and ERCOT over compensation for the response reserve service (RRS) the company provided during the February 2021 winter storm. It deferred making a decision until a later open meeting.

Engie and Viridity Energy Solutions ask to be reimbursed $47.5 million or credited for the 27 MW of RRS it delivered each day during Feb. 15-19, 2021. ERCOT said the complainants did not provide the RRS after Feb. 15, citing their failure to have confirmed trades for the ancillary service in the day-ahead market during those days. Engie and Viridity contend that following normal procedures was effectively impossible during the storm, when the ERCOT's grid came within minutes of a total collapse (*53377*).

SOAH's law judges in June *rejected* the Engie and Viridity complaint. They found the complainants did not show that ERCOT's actions violated any applicable law.

At issue is the grid operator's requirement to have capacity that supports an ancillary service trade or offer. Its protocols define capacity for noncontrollable load resources as their net power consumption minus low power consumption, which is the load available for interruption.

Engie's legal counsel said the load resources lost their capacity when deployed, preventing them from being scheduled in the next day-ahead market. Engie and Viridity sought remedial relief to receive $47.5 million for the service they provided during the storm.

ERCOT says the evidence indicated Viridity benefited by not participating in the day-ahead market, avoiding $65 million in ancillary service imbalance charges.

PUC Adopts EOP Report

The PUC also adopted staff's recommendation to approve a *report* on the power sector's weatherization preparedness and companies' emergency operations plans (EOPs). The report is due to the state legislature, which directed the report last year, by Sept. 30 (*53385*).

Business management consultant Guidehouse reviewed 691 electric entities' EOPs, checking the grid's ability to withstand extreme weather events in the coming year. It found the sector is "largely prepared" across the state for extreme weather, and its participants exhibit "basic" emergency preparedness programs and have measures in place to respond to weather events.

The firm noted its review was limited in scope and did not "comprehensively" cover resource adequacy, weatherization, system-hardening efforts or spare critical inventory. Guidehouse's suggested improvements included financial penalties for noncompliance and a greater focus on EOPs' actions to withstand extreme weather events.

"One example identified in multiple EOP submissions is the inclusion of a detailed list of food items needed for an entity's staff during emergency situations ... but the plans did not include strategies or equipment needs for field response," the report said.

About 70% of applicable entities provided EOPs or affidavits on no material changes. Guidehouse said the remaining 30% were "overwhelmingly low risk." ■

ISO-NE News

ISO-NE Consumer Liaison Group Talks Potential of Offshore Wind

Supporters Tout Reliability, Climate, Public Health Benefits

By Jon Lamson

NEW LONDON, Conn. — Activists, ISO-NE officials and state representatives from across New England convened in this port city to discuss the benefits of offshore wind to the region's power system — along with the challenges to deployment — at the RTO's Consumer Liaison Group meeting Sept. 12.

The New London port is one of the region's key staging areas for offshore wind. It was used as a staging and assembly point for the South Fork Wind Farm and is currently supporting the construction of the Revolution Wind project.

"We are bringing this industry to America," said Ulysses Hammond, the recently retired executive director of the Connecticut Port Authority, kicking off the meeting.

Speakers at the CLG generally spoke favorably of the significant reliability, climate and public health benefits that offshore wind could provide the region, while citing costs and transmission challenges as the key factors that could slow its deployment.

While New England states have set ambitious offshore wind goals, high costs have caused project cancellations and smaller procurements than many advocates have hoped for. Massachusetts and Rhode Island recently announced their selection of 2,878 MW from their multistate coordinated procurement, which initially sought up to 6,000 MW. (See *Multistate Offshore Wind Solicitation Lands 2,878 MW for Mass., RI*.)

Connecticut, which also participated in the coordinated procurement, announced that it is still evaluating the bids, putting into question the viability of one project selected by Massachusetts. (See *NY OSW: If at First You Don't Succeed, Try, Try Again*.)

Although high bid prices appear to have given some lawmakers second thoughts, offshore wind PPAs will likely save ratepayers money in the long run, said Josh Berman, senior attorney at the Sierra Club.

He highlighted the results of a recent *analysis* commissioned by the Sierra Club that found that adding 9 GW of offshore wind would save the region an estimated $630 million annually due to lower market clearing prices. The estimate was based on a $150.15/MWh

Al McBride, ISO-NE (left), and Abraham Silverman, John Hopkins University | *ISO-NE*

project cost, derived from the Sunrise Wind and Empire Wind projects. Massachusetts and Rhode Island have not yet announced the costs associated with their most recent solicitation. (See *Offshore Wind Projected to Save New Englanders $630M per Year*.)

Adding 9 GW of wind would also cut the region's power sector emissions by about 42% and provide about $362 million in annual public health benefits due to lower NOx and particulate emissions, Berman said.

Berman emphasized that the benefits would be socialized across the region's grid, even though the current PPA model largely revolves around individual states — or pairs of states — covering the entirety of a project's costs. He compared the dynamic to Connecticut's support of the Millstone nuclear plant and said collaboration and cost sharing between New England states will be a key component moving forward. (See *Connecticut Zero-Carbon Awards Include Nukes, OSW, Solar*.)

Susan Muller, senior energy analyst at the Union of Concerned Scientists (UCS), said offshore wind will also provide significant winter reliability benefits, as it typically performs better in lower temperatures. She highlighted a recent UCS *analysis* that found offshore wind additions would significantly reduce winter blackout risks in the region, echoing the findings of recent ISO-NE studies. (See *ISO-NE Study Highlights the Importance of OSW, Nuclear, Stored Fuel*.)

Muller added that ISO-NE's inventoried energy program and Mystic cost-of-service agreement, both aimed at ensuring winter resource adequacy, have cost ratepayers nearly $1 billion. And while Enbridge has proposed a significant gas capacity expansion into the region to reduce winter gas constraints, Muller said it makes far more sense to invest in offshore wind resources.

"If you're thinking about a new gas pipeline, you first need to talk with the communities that it is going through," Muller said. "The pipeline really seems to be the wrong path to take. Because we have offshore wind as an incredible opportunity before us, we think it's a no-brainer to go down the other path."

Liz Mettetal, a director at the consulting firm Energy + Environmental Economics (E3), said offshore wind and long-duration storage will have *combined reliability benefits* that are "greater than the sum of their parts" as both technologies scale up.

Mettetal said the region should consider timing storage procurements with renewable energy solicitations. She told the CLG that "we don't need storage on the grid until we have a ton of renewables, but they really will work together."

Abraham Silverman, a researcher at Johns Hopkins University and the facilitator of the Northeast States Collaborative on Interregional Transmission, emphasized the importance of preparing the grid today for the offshore wind resources that will come online in the coming decade.

"We are making decisions today for projects that are not going to come online until the early 2030s," Silverman said, adding that transmission projects to enable offshore wind will likely look like smart investments in 20 years, despite their significant upfront costs.

He said the long timeline of permitting and siting onshore transmission infrastructure makes today's efforts especially important.

Siting and permitting are "probably the most difficult part of the clean energy transition," Silverman said, adding that "getting the onshore grid ready is just as hard — if not harder — than getting the offshore grid done." ■

ISO-NE News

Mass. Gov. Healey Includes Permitting Reform in Budget Proposal

By Jon Lamson

Following the failure of the Massachusetts House of Representatives and Senate to reach common ground on a climate bill this summer, Gov. Maura Healey (D) has proposed to include clean energy permitting and procurement provisions in a supplemental budget bill announced Sept. 11.

While the permitting and siting reform framework largely has been agreed on for months, legislators were unable to overcome disagreements between the House and Senate over natural gas and competitive electricity supplier reforms before the end of the formal legislative session in July. (See *Mass. Lawmakers Fail to Pass Permitting, Gas Utility Reform* and *Mass. Legislature Faces Looming Deadline to Pass Permitting Reform*.)

The permitting and siting proposal would consolidate the approval process for clean energy infrastructure projects and impose a 15-month cap on the review of large projects and a 12-month cap on the review of small projects.

Sen. Mike Barrett (D), the lead Senate negotiator on the climate bill, has argued that expediting the permitting process — while important for the clean energy transition — could lead to increased infrastructure costs to ratepayers, and therefore must be coupled with the gas and competitive electricity supplier reforms intended to help offset some of the costs to ratepayers.

The Senate version of the climate bill would allow gas utilities to retire portions of the gas network if viable alternatives are available, update the state's pipeline replacement program with the goal of reducing ratepayer costs, and require annual filings from the gas utilities on their efforts to reduce emissions and minimize risks of stranded assets.

Healey's supplemental budget, however, declined to include gas or competitive supplier reforms. The governor wrote in a letter to legislators that the clean energy permitting reforms would help the state "capitalize on the potential to grow our clean energy sector and advance our climate goals."

The supplemental budget — if brought up in the informal session — could be halted by the vote of a single legislator; passing a bill in an informal session requires unanimous approval of all present lawmakers. This makes it unlikely the legislature will approve any of the more controversial climate proposals, and also could pose a challenge for the slimmed-down permitting and procurement proposals.

The legislature's next formal session starts in January, although the governor and top lawmakers have signaled interest in calling a special formal session focused on a separate economic development bill that legislators also failed to pass in July.

The inclusion of the permitting provisions without gas reforms spurred criticism from Barrett and climate activists.

"The governor and the House want us to pay for two separate — and *expensive* — systems to serve the same population's energy needs," said Becca Glenn of the advocacy group Mothers Out Front in a statement. "Massachusetts residents can't afford to prop up an aging gas system while also paying for a modern, clean energy system."

Barrett told *RTO Insider* he's disappointed with the supplemental bill proposal, noting that "all the Senate reforms intended to provide ratepayer relief have been stripped out." The proposal has undermined ongoing negotiations between the Senate and the House over the climate bill, he added.

"I'm not sure that the House will have any incentive to negotiate with us, because [the supplemental budget] gives them the minimalist outcome that they seek," Barrett said. "We had actually reached agreement on a significant number of secondary items, so there was real promise to these negotiations. The governor has upset all of that."

Rep. Jeff Roy (D), the lead negotiator on the House side, did not respond to requests for comment in time for publication, but he told the State House News Service he's "encouraged by what the governor is attempting to do."

Kyle Murray of the Acadia Center said the administration's inclusion of the permitting reforms in the budget bill "probably signals that they didn't sense likely movement" in the negotiations between the House and Senate.

He said reforms to expedite clean energy permitting and to enable the transition off natural gas are key aspects of the state's clean energy transition but added that "any climate bill that moves forward must take practical and common-sense steps to address the gradual decommissioning of the sprawling natural gas system. Any bill that does not do so is not acceptable."

A spokesperson for the Executive Office of Energy and Environmental Affairs said the governor's office "included time-sensitive energy provisions critical to the procurement, permitting and siting of energy projects" in the supplemental budget, adding that the administration "continues to support the climate bill and will continue to work with the Legislature on its passage."

Beyond the specific reforms at hand, Barrett also expressed dismay at the strong opposition that has come from the gas industry to the Senate's efforts to facilitate a transition away from gas.

"This has been an eye opener," Barrett said. "We've got to get off natural gas — consciously but effectively — but after this year's experience, I can predict a tough road ahead even in a very blue state."

The state's electric and gas utilities historically have been the most influential interests on climate policy in the state, according to a 2021 analysis from Brown University researchers. Over the course of the 2023/24 legislative session, investor-owned gas and electric utilities cumulatively reported about $1.6 million in spending on lobbying in the state.

Clean Energy Procurement

The supplemental bill also proposed significant changes to the state's clean energy procurement process, incorporating aspects of both the House and Senate climate bills.

The bill would enable the state's Department of Energy Resources (DOER) to pursue coordinated solicitations with other states for clean energy generation or transmission that would help the state meet its policy goals in a cost-effective manner.

It also would direct the DOER to review the effectiveness of the state's existing clean energy procurements, and to "make recommendations regarding the future procurement of clean energy resources for the purposes of ensuring compliance with statewide greenhouse gas emissions limits."

It also specifically directs the DOER to solicit up to 5,000 MW of storage resources over the next four years, including 3,500 MW of mid-duration storage (lasting between four and 10 hours), 750 MW of long-duration storage (between 10 and 24 hours) and 750 MW of multi-day storage (greater than 24 hours). ■

ISO-NE News

ISO-NE Responds to Feedback on Capacity Auction Reforms Scope

By Jon Lamson

ISO-NE's Capacity Auction Reforms (CAR) project *will include* an evaluation of additional resource accreditation modeling enhancements, the RTO told the NEPOOL Markets Committee on Sept. 10.

The RTO is also planning to estimate seasonal tie benefits in its resource adequacy assessment model, it said. The remarks came in response to feedback it solicited on the "straw scope" of the project, which aims to transition the Forward Capacity Market to a prompt and seasonal market. (See *ISO-NE Outlines 'Straw Scope' of Capacity Market Reforms*.)

Some stakeholders argued that ISO-NE's resource accreditation modeling does not accurately reflect the region's risk profile, including the duration of events. (See *ISO-NE Capacity Accreditation Reforms Spur Energy Storage Concerns*.)

"As part of CAR, the ISO plans to assess whether it can make further enhancements to the modeling and accreditation proposal to better align accreditation values with contributions to resource adequacy," said Chris Geissler, ISO-NE director of economic analysis. The RTO also plans to consider how it models intermittent and limited-energy resources, along with improvements to the load model, he said.

Other stakeholders expressed concerns that the new accreditation methodology would not consider the marginal reliability impact (MRI) of tie benefits, potentially causing the RTO to overestimate the reliability benefits of interties.

In *comments* submitted prior to the meeting, Calpine argued that "any supply source, including imports, used to meet capacity requirements should be counted similarly and subject to similar performance requirements" and that ISO-NE "should apply this standard to the CAR work."

Geissler said the RTO will work with its neighbors to evaluate seasonal tie benefits, which "represent the expected contribution from other regions during emergency conditions."

However, ISO-NE does not plan to calculate MRI values for tie benefits, or to subject tie benefits to Pay-for-Performance (PFP) rules, Geissler said. He noted that tie benefits will be modeled in resource adequacy assessments, which are used to determine the RTO's installed capacity requirement. He added that "tie benefits are not directly competing" with capacity resources to meet this requirement.

Geissler also told the MC that ISO-NE is not planning to include an evaluation of how the capacity market treats resource retentions. He added that, in a future phase of work, the RTO may consider broader changes to its rules for reliability-must-run contracts if it determines that retentions for energy security reasons are needed.

The RTO also is not planning to model resource start times because of the constraints of GE MARS, its resource adequacy modeling software, despite interest from some stakeholder groups, Geissler said.

"Assessing changes to the resource adequacy platform would be a significant, multiyear effort that would take resources away from other parts of the CAR effort and jeopardize the ISO's ability to complete CAR in time for [capacity commitment period] 19," Geissler said.

In a *memo* published prior to the meeting, environmental advocacy groups pushed the RTO to model startup times, arguing that it is a necessary step to fairly compensate resources for their ability to support the power system on short notice.

"Units with lengthy startup times simply do not offer the same resource adequacy value as more flexible ones," the organizations wrote. "We understand that this will involve substantial resources, but given that ISO has already committed to spending several years on overhauling its capacity market reform, now is the best time to address this important consideration."

The groups also urged the RTO to model "correlated outages and ambient temperature adjustments" as part of the CAR project.

Gas and diesel resources are "susceptible to both cold and hot temperature-dependent forced outages," the organizations said while calling on ISO-NE to "model these reliability impacts as accurately as possible."

Geissler said ISO-NE is still considering whether to include temperature adjustments and correlated outages in the project scope, noting that the topic "raises technical modeling questions that must be more fully assessed before a decision can be made."

He added that ISO-NE is planning to model correlated outages of gas resources related to the region's gas constraints in the winter.

IMM Quarterly Markets Report

Wholesale market energy costs were down by 23% this spring relative to that of 2023 because of lower natural gas prices and capacity clearing costs, according to the ISO-NE Internal Market Monitor's *quarterly markets report*.

The real-time hub LMP averaged $24.64/MWh, ranging from 9 to 13% lower than in spring 2023. The average load (11,869 MW) was up by about 180 MW per hour in part from higher temperatures in May compared to the prior year.

Nuclear generation rebounded after several down seasons because of lower rates and accounted for about 28% of the average output. Natural gas remained the largest generation source at 45% of the average output. Imports decreased because of a drought in Canada that affected hydro reservoir levels. ■

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ISO-NE News

BOEM Announces Gulf of Maine Offshore Wind Lease Sale

By James Downing

The U.S. Bureau of Ocean Energy Management announced Sept. 16 it will conduct an offshore wind energy lease *sale* on Oct. 29 for eight areas on the Outer Continental Shelf in the Gulf of Maine.

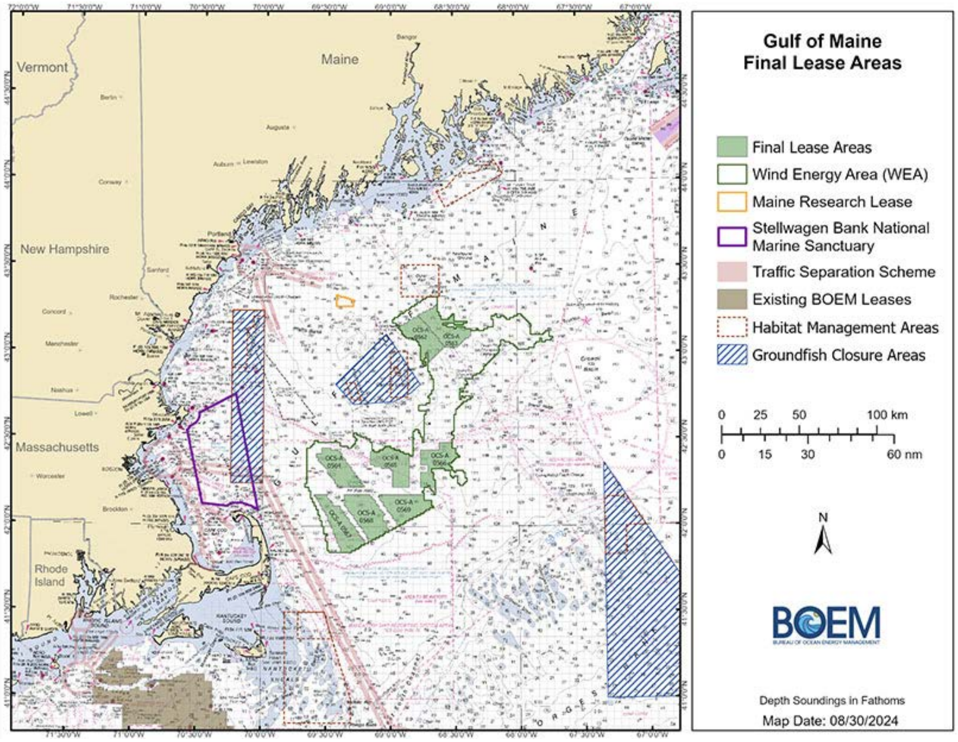
The gulf stretches from Cape Cod to Nova Scotia and the leases include areas off Massachusetts near Boston, New Hampshire and Maine. Unlike the rest of the East Coast, the Gulf of Maine has waters that are too deep for traditional offshore wind, so any projects would have to use floating turbines.

The announcement comes less than a month after U.S. Department of the Interior and BOEM announced a "research lease" that will allow the state of Maine build up to 12 floating turbines that could produce 144 MW. (See *Maine Approved for Floating Wind Research Lease*.)

"The growing enthusiasm for the clean energy future is infectious," said Interior Secretary Deb Haaland. "Today's announcement — which builds on the execution of the nation's first floating offshore wind energy research lease in Maine last month — is the result of years of thoughtful coordination between our team, the Gulf of Maine states, industry and the Tribes and ocean users who share our interest in the health and longevity of our ocean."

The leases could produce about 13 GW of offshore wind power if fully developed, which could power more than 4.5 million homes. Since the beginning of the Biden administration, BOEM has held five offshore wind lease sales and approved 10 commercial-scale offshore wind projects.

The announcement is based on the best available science, including an ecosystem-based spatial suitability model conducted by the National Centers for Coastal Ocean Science.



A map from BOEM showing the leases available in the Gulf of Maine for the Oct. 29 auction. | *BOEM*

BOEM also spent more than two years engaging with Tribes, the fishing industry and other stakeholders across the region to help shape the lease areas.

The overall area is about 120,000 acres less than what BOEM included in its proposed sale notice that was announced earlier this year. The bureau tried to avoid offshore fishing grounds, sensitive habitats, and existing and future vessel transit routes, while retaining enough acreage to support the region's offshore wind energy goals.

Winning a lease does not confer the right to build an actual power plant, but it gives developers the right to submit project specific plans that would be subject to environmental, technical and public reviews before any approvals.

BOEM has identified 14 firms that are legally, technically and financially qualified to bid in the lease auction: Avangrid Renewables, Equinor Wind US, US Mainstream Renewable Power, Diamond Wind North America, Hexicon USA, Seaglass Offshore Wind II, TotalEnergies SBE US, Pine Tree Offshore Wind, energyRe Offshore Wind Holdings, OW Gulf of Maine, Repsol Renewables North America, Maine Offshore Wind Development, Corio USA Projectco and Invenergy NE Offshore Wind.

Bidders wishing to participate have to file financial forms by Sept. 27 and post $2 million deposits for each lease area they plan to bid on (up to a maximum of two) by Oct. 11. ■

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ISO-NE News

Mass. Court Upholds Approval of Controversial Eversource Substation

By Jon Lamson

The Massachusetts Supreme Judicial Court (SJC) on Sept. 11 *upheld* the Energy Facilities Siting Board's (EFSB's) approval of a controversial substation in East Boston, likely concluding the 10-year fight over the project.

The court ruled that the petitioners, the Conservation Law Foundation (CLF) and GreenRoots, did not meet the heavy burden of proof required to overturn the EFSB's approval of the project.

"We conclude that the board's decision is lawful, was supported by substantial evidence, and was not arbitrary, capricious or otherwise an abuse of the board's discretion," the SJC found.

The project, currently under construction, is sited on the bank of the Chelsea Creek near a public park, homes and a new police station.

Eversource Energy, the electric distribution company responsible for the project, had argued the substation is needed to meet load growth in the area and preserve electric reliability.

However, the project was met with significant opposition by residents and environmental advocacy organizations, which argued it will add to the significant burden of pollution already facing the neighborhood. The surrounding area is *classified* by the state as an environmental justice neighborhood, meeting the definition's criteria for income, minority population and language isolation.

In a non-binding 2022 ballot question, 83% of Boston voters opposed the project at the selected site, while politicians including Boston Mayor Michelle Wu (D) and U.S. Sen. Ed Markey (D) have voiced their opposition to the project.

In challenging the EFSB's approval, CLF and GreenRoots argued the board did not adequately weigh the project's environmental burdens with its benefits to the community and said the board improperly pre-empted the review processes of two local agencies.

The groups also took issue with the substation's designation as a water-dependent facility when granting its tidelands license.

The court was not persuaded by these arguments, finding "no error in the board's considerations of environmental protection, public health and public safety."

The location of Eversource's substation in East Boston | *Eversource*

The project's opponents expressed disappointment with the court's ruling, arguing it is a failure to protect residents of the environmental justice neighborhood.

"East Boston residents endure major pollution and other environmental hazards that threaten their health and safety, and this project was poorly sited in a flood-prone area," said Anxhela Mile of the Conservation Law Foundation. Mile added that the decision underscores the "need to reform how the commonwealth permits energy infrastructure and assesses the cumulative environmental and health risks a community faces.

"GreenRoots and the East Boston community affected by the Eversource project are disappointed with the MA SJC's decision to allow the project to move forward, but honestly we're not surprised," said John Walkey of GreenRoots. "The siting and permitting process is broken from any perspective you look at it."

He noted that the fight over the substation was an important factor in passing environmental justice protections into state law in 2021, and in centering environmental justice protections in recent efforts to pass permitting reforms in the state.

"We have also seen Eversource itself change its own approach to engaging communities in their recently proposed substation in the Hyde Park neighborhood in Boston," Walkey added, noting that the company engaged the community before filing with the EFSB and "brought up the question of Community Benefits Agreements right out of the gate."

"However, this is cold comfort for an already environmentally over-burdened East Boston community now saddled with additional poorly and unjustly sited industrial infrastructure," Walkey said.

Eversource spokesperson William Hinkle said the court's decision affirms the substation "is critically needed to address local capacity constraints, support a rapid growth in electric use and reliably serve our customers in East Boston and Chelsea."

"We cannot leave any customers or communities behind in the clean energy transition and achieving decarbonization and electrification goals while ensuring that all customers have access to clean energy opportunities will require a significant amount of new electric infrastructure," he added.

The Massachusetts Department of Public Utilities recently approved the electric sector modernization plans of the state's three investor-owned electric utilities, establishing the framework for major new investments in electric infrastructure across the state. (See *Mass. DPU Approves 1st Round of Utility Grid Modernization Plans*.)

Meanwhile, in a proposed supplemental budget bill, Gov. Maura Healey (D) included reforms to streamline and expedite the state's clean energy permitting and siting processes. The proposal would reduce the timeline for reviewing infrastructure projects — including substations — while requiring a cumulative impact analysis to account for existing pollution sources and public health burdens, a requirement that was not in place for the review of the East Boston substation. (See related story *Mass. Gov. Healey Includes Permitting Reform in Budget Proposal*.)

Hinkle noted the company has completed about 75% of the work on the station foundations, with construction expected to extend through the third quarter of 2025. The company expects the substation to come online in late 2025.

The company estimated in late 2022 the project will cost about $103 million, compared to the initial $66 million estimate presented to the EFSB. Eversource attributed this increase to construction delays and higher costs of materials and labor. ■

MISO News

MISO, TOs Argue Self-funding Necessary for Transmission Development

RTO Responds to FERC Show-cause Order

By Amanda Durish Cook

MISO and its transmission owners defended their practice of allowing transmission owners to self-fund network upgrades in separate filings Sept. 11 responding to FERC's Order to Show Cause (EL24-80).

FERC in June said grid operators' practice of allowing TOs first crack at financing — and therefore earning a return on — the network upgrades necessary to bring generators online could be biased against interconnection customers, who may experience higher interconnection costs as a result.

The commission ordered MISO, PJM, SPP and ISO-NE to explain how their tariff language on the initial funding is fair or, alternatively, propose changes to make their policies impartial. It also suggested that TO self-funding creates barriers to interconnection (*EL24-80, et al.*). (See *FERC Issues Show-cause Order on TO Self-funding in 4 RTOs*.)

For more than a decade, MISO's practice of TO self-funding has been the subject of oscillating rulings between FERC and the D.C. Circuit Court of Appeals. RWE Renewables, NextEra Energy and EDF Renewables recently claimed their costs "double or increase exponentially" when TOs take the lead on funding network upgrades.

In *their filing*, the TOs argued that eliminating their unilateral ability to self-fund upgrades would decrease, rather than promote, the capital investment needed for transmission projects. They also said FERC has no basis to eradicate TO self-funding after establishing it in Order 2003.

MISO insisted its TO initial funding practice is fair and said it never has "observed any instances of [it] being used as a tool to inflate the costs of network upgrades or create advantages for some generation projects vis-à-vis others." The RTO said a TO electing to self-fund does not affect the interconnection service, but it did acknowledge it does increase the costs for interconnection customers.

"TO initial funding does increase the cost of interconnection service to the interconnection customer, but only because that cost would not otherwise include a … return on capital," MISO said. "From the perspective of [a] transmission owner, the actual cost of the operating and maintaining the funded network upgrade is unchanged." It added that eliminating the self-funding option will not necessarily result in lower costs because interconnection customers also could require a return on capital and shift that cost to ratepayers.

MISO also said its procedure affords interconnection customers the opportunity to suggest alternatives to and investigate the justification for a network upgrade so they're not on the hook for oversized projects that would pad TOs' bottom lines. The RTO also said interconnection customers can pursue alternative dispute resolution or choose to file unexecuted facilities service agreements to challenge upgrade costs.

The RTO insisted its three-phase interconnection queue design provides enough oversight so that "any network upgrade and corresponding self-fund election has a transparent, multistep history, with MISO involvement at each step."

However, MISO added a caveat that it "has only limited insight into its transmission owners' internal functions, needs and decision-making," so it could not answer all questions posed by the commission. In those cases, MISO submitted its TOs' answers.

The TOs adopted a more full-throated defense. They said FERC's show-cause order "poses questions that make it apparent the commission has made up its mind" to eliminate the self-funding option "without regard to the long-term effect this will have on transmission owners and other customers they serve."

They argued that it is imperative they be able to earn a return on assets they will own, operate and maintain for the duration of their useful lives. They said the show-cause order amounts to "misguided policy goals behind an undue discrimination theory" and argued that no one has been able to produce evidence that TO initial funding causes undue discrimination "in the 13-plus years that TO initial funding has been before the commission."

The TOs also said that, in an era of supersized transmission expansion, it appears that FERC has forgotten to "balance interests and to ensure that native load customers are not negatively affected as a result of third-party generator interconnection." They said their financial viability should be maintained and FERC should be careful not to "strike a one-sided 'balance' in favor of cheaper interconnections for generators."

The 345-kV Big Stone South to Ellendale line in the Dakotas | *Otter Tail Power Co.*

"Transmission owners bear substantial risks associated with owning, operating and maintaining said transmission facilities, and stand to lose the right to self-fund network upgrades and, with it, the ability to earn a just return on an entire class of interstate transmission facilities, in a grossly unfair proceeding," the TOs said.

If they are denied the opportunity to make a return on network upgrades, the TOs argued that it would constitute an attack on their business model and is akin to the "taking of private property for public use without just compensation." It is "overly simplistic" and "reductionist" to think that TOs should not be able to earn a return on network upgrades simply because the money for them comes from generation developers, not themselves, they argued. They also said that they would never build unnecessary network upgrades because MISO independently studies interconnection needs.

FERC should terminate the proceeding with prejudice, the TOs concluded. ■

New MISO Day-ahead Market Engine to Emerge Soon After Delay

By Amanda Durish Cook

MISO operators | *MISO*

MISO's new day-ahead market clearing engine should move into standalone production near the end of the month following a delay in testing, executives with the RTO have said.

The new engine is one piece of MISO's yearslong work to replace its aging market platform. Earlier this year, MISO said it planned to begin running its day-ahead market on the new engine in May. (See *MISO Sets Sights on 2025 Completion for New Market Platform*.)

"I can see the light at the end of the tunnel. I know I've been here for four months, but this is years and years of work," Nirav Shah, MISO's new chief digital and information officer, said during a Sept. 11 teleconference of the Technology Committee of the RTO's Board of Directors.

Shah later confirmed to board members that "there were absolutely delays from a testing perspective."

CEO John Bear acknowledged in June that MISO encountered challenges bringing the day-ahead market into parallel operations with the existing platform. At the time, he said the RTO was working with vendor General Electric to iron out problems that are preventing MISO from cutting over to the new platform and retiring the legacy system.

"The problems and challenges we're addressing here will help us move faster on the rest of the project," Bear said.

Shah said the testing phase of the day-ahead market clearing engine is now proceeding smoothly and MISO is in daily communication with GE.

The delay will likely impact the testing of MISO's new real-time market clearing engine, which was expected to begin parallel operations in the third quarter of this year, but Shah said that start time is looking tenuous.

However, Shah said MISO plans to finish most of the projects associated with its market platform replacement by the end of 2025.

The RTO said it remains on track to launch its new one-stop model manager and end parallel operations of its old, siloed modeling systems in 2025.

MISO said it has worked with vendor Siemens to standardize data fields across the RTO's separate modeling structures to make a cohesive model manager. It expects to complete data migration sometime in the first quarter of next year. ■

MISO News

MISO Says 2nd Long-range Tx Plan to Cost $21B, Deliver Double in Benefits

Monitor Incredulous over RTO's Estimate; Says Portfolio Set to Produce Only 0.5:1 Ratio

By Amanda Durish Cook

MISO said its second, mostly 765-kV long-range transmission plan will provide the Midwest region with at least a 1.9:1 benefit-cost ratio and cost $21 billion, lower than its earlier estimated $23 billion to $27 billion.

The grid operator announced the approximations at stakeholder workshops Sept. 10 and 13. Even with the slightly lower costs, MISO's Independent Market Monitor is incredulous the portfolio would deliver nearly double its cost in benefits.

Jeremiah Doner, MISO director of cost allocation and competitive transmission, said MISO refined its cost estimate using facility-specific details.

"That number may move around a little bit. But I think that $21 billion is where the portfolio stands," he told stakeholders. "We don't expect at this point in the process to be adding projects, so we don't expect that number to materially change."

Doner said MISO tried to minimize costs by proposing to co-locate some of the new 345- and 765-kV lines with existing structures.

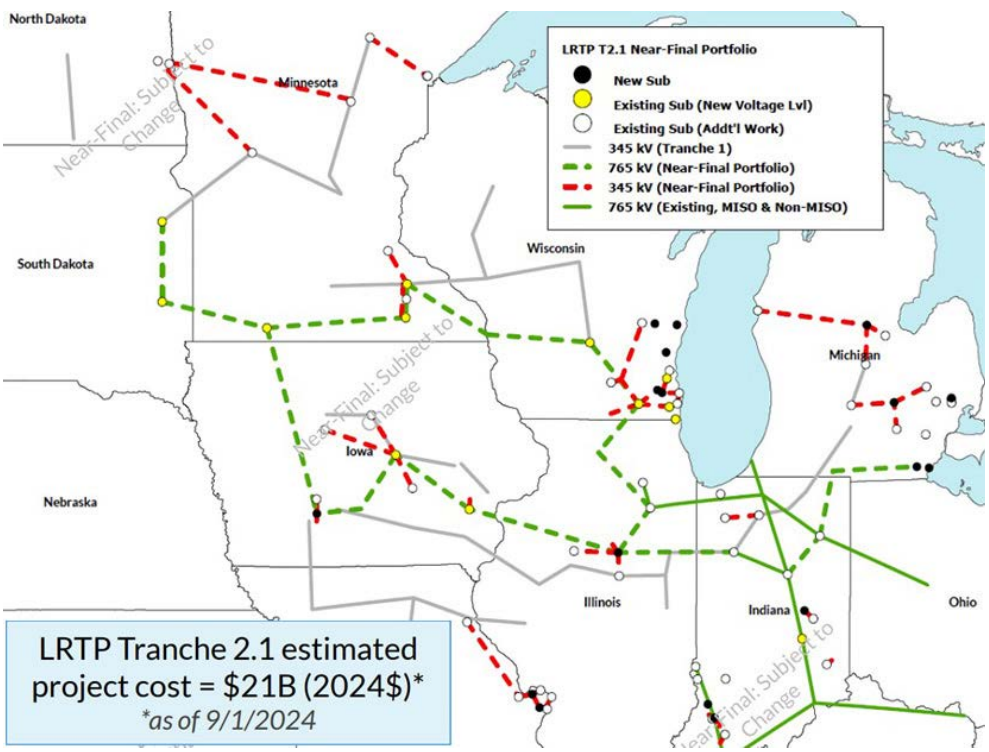
"We know there's always more risk in the regulatory permitting process when you have to seek new rights of ways," Doner said. He added that MISO is in discussions with its transmission owners about what would be the most feasible route for the line.

MISO is also exploring routing a 765-kV line on an existing 161-kV route because it will cross an "environmentally sensitive" area from Wisconsin into Minnesota over the Mississippi River, Doner said. "We recognize that's not a common practice," he added.

At $21 billion and roughly 4,000 line miles, the second plan doubles the first LRTP portfolio, both in terms of costs and line miles. Doner reminded stakeholders the second portfolio has been in the works since 2022, when MISO moved to establish a projection of what the system would look like in 20 years.

The Ratio

Doner said the portfolio demonstrates "at least" a 1.9:1 benefit-to-cost ratio when analyzing its projects using MISO's nine benefit metrics, which include the advantages of decarbonization, ability to withstand extreme weather and assistance in avoiding loss-of-load events, in addition to the more mundane adjusted production costs.



LRTP benefit ranges by cost allocation zone in MISO Midwest | *MISO*

"We know these assets are going to be in service much longer than that," Doner explained, adding that MISO was intentionally conservative to show the projects will more than pay for themselves over their first 20 years of service.

Doner said if MISO assumes the lines have a 40-year lifespan, total benefits could rise to 3.8:1. He added that with the conservative estimate, all of MISO's cost allocation zones in the Midwest region are set to experience at least a 1.3:1 benefit-cost ratio.

"I think it's important to show at least a 1:1 benefit-cost ratio in each of the cost allocation zones," Doner said.

On a 20-year basis, MISO estimates the second LRTP portfolio will conservatively save MISO Midwest $16.3 billion because of the mitigation of reliability issues; $15.7 billion from avoided capacity costs; $8.1 billion in congestion and fuel savings; at least $7 billion in decarbonization assistance; nearly $3 billion in capacity and energy savings from a decrease in system losses; and $1 billion in avoided transmission investment. MISO also estimates the LRTP portfolio will save the Midwest at least $392 million from the reduced risk of extreme weather and $76 million in reduced transmission outage costs.

Skepticism

However, Monitor David Patton said he *continues* to believe three of the nine benefit metrics (avoided capacity costs, avoided reliability risk and decarbonization) are outright invalid or overstated and if they are deleted or significantly scaled back, the portfolio's benefits would not come close to covering its costs. (See *MISO Closing in on Final, $25B LRTP; Monitor Repeats Reservations*.)

"If you adjust for those metrics, the overall benefit metric goes down to 0.5:1," Patton said, adding that he thinks it is "really, really important to scrutinize" MISO's methodology.

"This is not about reliability. This is about a choice to build generation to further others' policy goals," North Dakota Public Service Commission staffer Adam Renfandt said in criticizing the portfolio.

Doner said when MISO developed its 20-year outlook that the portfolio is built upon, it examined which direction members were taking "across the whole footprint, not just in pockets

MISO News

of the MISO system."

MISO planner Joe Reddoch said the analysis showed the portfolio would reduce constraints and increase system capacity so that the RTO can meet its capacity needs with fewer resources.

Patton pushed back on the message that MISO faithfully followed its members' resource plans when crafting the portfolio. He said that to model resources, the RTO relied on the Electric Power Research Institute's Electric Generation Expansion Analysis System (EGEAS), which he said only minimizes costs in deciding what to build and ignores potential revenues entirely, leading to "very unrealistic" fleet assumptions.

Patton said he doubted the avoided capacity costs MISO has estimated and that members naturally would build more deliverable resources on the other side of transmission constraints if the transmission never were constructed. He said it's highly unlikely members would continue to build generation in sites that are undeliverable to load. Patton added that if MISO approached its members and said it was not going to meet its resource adequacy obligations, members would adjust resource planning, which "pretty quickly" would reduce the LRTP's benefits by "tens of billions."

"You've cited an undeliverable collection of resources if we don't build [the second portfolio], but our markets are designed to take care of that. To characterize that as a benefit is pretty misleading," Patton said.

Doner said members have asked MISO to build a dependable system around their future plans. He also said it is not so simple for members to "move generation around," citing wind- and solar-rich locations in the footprint.

"We have transmission planning responsibilities, not resource planning responsibilities. We really do rely on what our members are telling us that they're going to build," Doner countered.

Patton also said MISO is off base by establishing the value of the portfolio's avoided reliability risks on the value of lost load (VoLL). He said in "no world" would the RTO allow reliability risks to become severe enough to shed load. Instead of lost load, Patton argued MISO should base the benefit on which transmission facilities would be built without the LRTP portfolio. MISO needs "an accurate 'but for' case," in which it analyzes which shape its system will take without the second portfolio, he argued.

"Calculate something that's real. This is not real," Patton said. It's "unconscionable" to expose customers to transmission investment based on "imaginary" and "massively overinflated" benefits, he said.

Jim Dauphinais, an attorney representing multiple industrial customers in MISO, said the use of VoLL in the benefit is "highly problematic."

However, Jeff Eddy, director of transmission planning for ITC Holdings, warned stakeholders that "there are big dollars behind outages" and pointed to Texas as an example. Eddy said that if anything, MISO was being conservative on the portfolio's $16 billion reliability value.

"We know that these backbone lines really do provide benefits," Sustainable FERC Project attorney Lauren Azar added. "I hope no one is questioning the benefits that regional backbone lines bring to the region."

Reddoch said it's difficult to compare the numerous, scattershot baseline reliability projects MISO would need on a five- to 10-year horizon with the 20-plus-year reliability benefits the second LRTP portfolio would achieve. However, he said the portfolio likely would be more economical than smaller, piecemeal projects to comply with NERC standards.

"This has always been a challenge in the industry to monetize reliability," Doner added.

North Dakota PSC Commissioner Julie Fedorchak said she was "dubious" that all MISO members would know where their projects will be located 20 years into the future, suggesting the RTO took liberties with its siting assumptions.

WEC Energy Group's Chris Plante said he would like MISO to admit that its planners fashioned a hypothetical resource expansion only with its members' carbon reduction goals in mind. "My expansion plans don't go out much more than seven years," he said.

Doner said that while it is not "100% member plans" that make up the 20-year future, it nevertheless comprises mostly member plans, and where there are not explicit plans, MISO sought extensive member input.

MISO Vice President of System Planning Aubrey Johnson said the RTO made "over 500 adjustments" to its original resource siting assumptions after speaking with its stakeholders throughout the planning process.

"Good golly, I really wish we could build regional backbone projects sooner than eight to 15 years in the future," Azar said, urging stakeholders to consider the timeline to build transmission. "MISO has no choice but to essentially site the resources in the models. All modeling is necessarily wrong, but that doesn't mean we shouldn't be doing it. I really just urge folks to think about the reality of how long it takes to build these really big projects."

"I've never known a resource planner who can tell me exactly what they're going to do," Eddy agreed. "This is high-level stuff, and I support what MISO is doing." He said stakeholders seem to be losing sight of what MISO's big-picture, future planning was intended to accomplish.

Plante said it seems MISO is rushing for December board approval rather than making sure "sound planning principles" are applied to the portfolio.

"Given the magnitude of the expansion planning here, we need to be careful that we establish sound foundations," Plante said, adding the projects will be subject to scrutiny at state regulatory agencies.

"We disagree that there's a lack of analysis here. We believe this is thorough," said Jeanna Furnish, MISO director of expansion planning. ■

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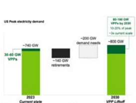
NetZero Insider



Could Virtual Power Plants Replace Natural Gas Peakers?

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MISO News

FERC Refuses MISO and MDU Complaints Regarding Crypto-strained MISO-SPP Flowgate

By Amanda Durish Cook

FERC has dismissed separate complaints from MISO and Montana-Dakota Utilities Co. over a MISO-SPP flowgate chronically stressed by a North Dakota cryptocurrency mining operation.

The commission issued a Sept. 10 order, refusing the pair of complaints; it said neither MISO nor Montana-Dakota Utilities (MDU) proved that the Charlie Creek flowgate in North Dakota failed to meet the criteria for market-to-market (M2M) coordination, nor was SPP in the wrong for continuing to insist on M2M coordination (*EL24-61*).

MISO and MDU have been sparring with SPP over the flowgate since last year, when cryptomining facility Atlas Power Data Center opened and brought 200-MW load to SPP's transmission-constrained Northwest North Dakota load pocket, which now has a peak load of about 1.5 GW but only approximately 1 GW of import capability. (See *MISO Lodges 2nd Complaint Against SPP over Disputed Crypto Load on M2M Flowgate*.)

FERC said it disagreed with MISO and MDU that SPP violated sections of the MISO-SPP joint operating agreement, that MDU incurred duplicate congestion charges and that the rules MISO and SPP rely on for M2M termination are unreasonable.

The commission found that "MDU and MISO have not demonstrated that SPP acted unreasonably in declining to grant consent to remove the Charlie Creek Flowgate from the market-to-market coordination process."

SPP has maintained that Charlie Creek remains eligible for M2M coordination based on the RTOs' flowgate studies, which it argued determine hundreds of other MISO-SPP flowgate designations.

MISO and MDU have argued that although the Charlie Creek Flowgate passes MISO and SPP's flowgate studies, its M2M status should be revoked because the RTOs' coordination is helping SPP manage a local issue caused by data center load growth, and not a regional issue. The two said the congesting spikes caused by the Atlas Power Data Center are squarely in SPP's territory and said SPP's insistence on M2M coordination is at the detriment of MISO market participants and customers.

The Atlas Power Data Center in Williston, North Dakota | *KFYR TV*

MISO last year initiated a formal dispute process with SPP over the flowgate. By March, it asked FERC to terminate M2M coordination on Charlie Creek and requested refunds on the M2M coordination charges it paid to SPP beginning in April 2023.

MDU filed a complaint against MISO and SPP early this year, saying it was overcharged $18 million for congestion management because the two RTOs were conducting unwarranted M2M coordination. MDU, a MISO member, has 150 MW of load and two 115-kV lines in the load pocket and relies on network integration transmission service from SPP to serve load when its own transmission is insufficient.

MISO claimed that improper M2M coordination cost its members $38 million in M2M charges to manage congestion. The grid operator also argued that SPP's approval of a temporary remedial action scheme for the Charlie Creek flowgate shows that the M2M coordination is being used to address a local issue wrought by load growth.

MISO's Independent Market Monitor further argued that, during periods of market-to-market coordination, MISO could provide less than 1 MW of relief on the Charlie Creek flowgate, while curtailment of Atlas' load in SPP could provide more than 90 MW of relief.

However, FERC said MISO and MDU were misreading the definition of an M2M flowgate as laid out in the MISO-SPP joint operating agreement. FERC said while a section of the RTOs' Interregional Coordination Process says M2M coordination should be reserved for issues that are regional and not local in nature, that's not an explicit prerequisite for a flowgate to be eligible for an M2M flowgate designation.

Because it determined the regional issue threshold wasn't a requirement for M2M coordination, the commission declined to determine whether the added cryptomining load constitutes a local issue.

FERC pointed out that SPP provided evidence that revoking Charlie Creek's M2M flowgate status might risk SPP needing to resort to transmission loading relief or load shedding.

FERC also refused to deem MISO and SPP's Interregional Coordination Process unreasonable because it allows either MISO or SPP to refuse to lift M2M designation even when the other RTO can offer little congestion relief. MISO argued that the mutual agreement condition amounted to an "unconditional veto."

But the commission said the rules give MISO and SPP "reasonable discretion on an equal basis to mutually agree to add or remove market-to-market flowgates without any conditions or requirements."

FERC decided SPP acted reasonably by not agreeing to remove M2M coordination. It said SPP provided evidence that it can redispatch to alleviate the flowgate in "most" hours. FERC also said keeping up the M2M coordination "helps create an appropriate market signal for MISO to dispatch generating units within its footprint that have a significant generator shift factor on the flowgate," making for a more efficient market solution versus terminating M2M procedures.

Because it denied the complaints, FERC likewise denied a related waiver request from MISO that would have allowed the RTO to adjust SPP's Integrated Marketplace settlements beyond the current 365-day limit (*ER24-1586*).

Nearby Basin Electric Power Cooperative announced plans in May to build a 1.4-GW gas-fired power plant to address growing demand from North Dakota's data center industry. ■

NYISO Proposes Increased Budget, Admin Rate for 2025

By Vincent Gabrielle

NYISO on Sept. 6 presented its $204 million draft *budget* for 2025 to the Budget and Priorities Working Group, with an administrative rate of $1.319/MWh based on a 154,700-GWh transmission throughput.

The proposed budget is a 4.72% increase over 2024's $194.8 million. The proposed Rate Schedule 1 surcharge — the ISO's administrative fee to recover its operating costs from members — is nearly 3% higher than this year's $1.281/MWh. The surcharge is billed to all users of transmission lines based on the calculations set forth in NYISO's tariff.

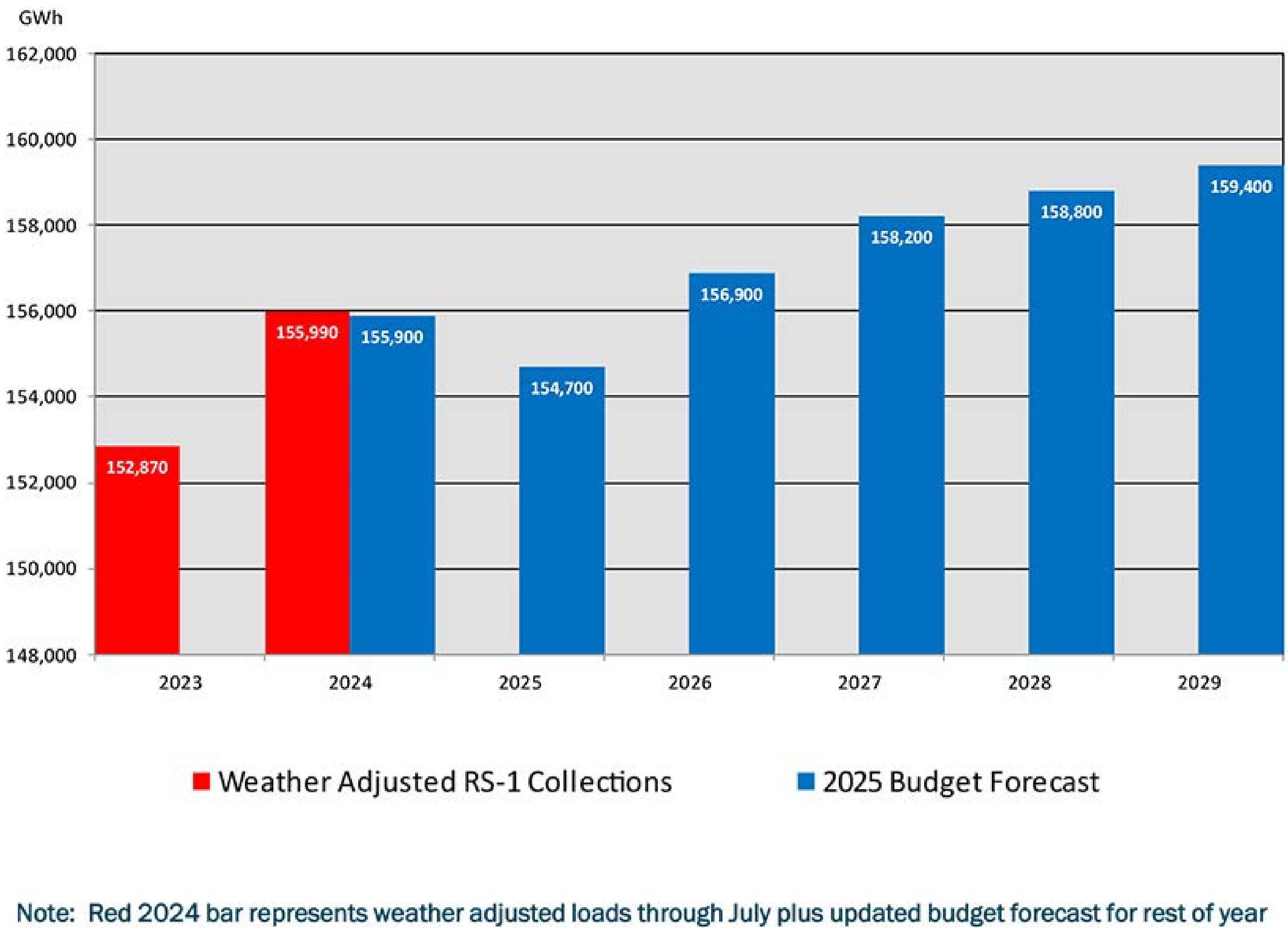
"The increase in the revenue requirement for 2025 relative to 2024 is $9.2 million, which is about 4.7%," NYISO CFO Cheryl Hussey told stakeholders. "The projected 2025 megawatt-hour throughput is an increase of 2.6 million MWh, which is an increase of 1.7% compared to 2024."

Hussey reported that NYISO is projecting a 2024 budget surplus because of overcollections under RS1 and spending being under budget. The ISO is therefore proposing an RS1 carryover of $3 million into the 2025 budget. This would reduce the impact of 2025 cost increases by approximately 2 cents/MWh, Hussey said. She also explained that if the carryover were not used to decrease the cost of RS1, it would be used to pay down debt.

"For example, in 2023, we used $5 million as a carryover, and then the balance we used to pay down debt," Hussey said. "In recent years, we've used a surplus to pay down debt. 2023 was the first time in a number of years that we proposed a carryover."

Debt servicing was projected to increase in 2025 to $7 million, an increase of about $4.8 million.

Mark Younger, of Hudson Energy Economics, requested that NYISO provide more information about the kinds of debt the ISO had currently so stakeholders could see whether paying off high-interest and variable-interest



Each transmission customer that participates in the physical market pays a charge for NYISO's recovery of annual budgeted costs under Rate Schedule 1. This graph shows the forecasts for the number of gigawatt-hours that NYISO anticipates charging for in upcoming years. | *NYISO*

NYISO News

loans or a carryover would be a better use of funds. Hussey said NYISO might be able to present something to address that at future meetings.

"Why are your debt services going up?" asked Amanda De Vito Trinsey of Couch White, representing New York City.

Hussey explained that in 2024 and 2025, NYISO was borrowing more money to pay for its increased project portfolio and infrastructure capital needs. In 2024, the ISO had borrowed $37 million to pay for its projects.

"Obviously, the more money we borrow, we need to pay that back, and that leads to increased debt service costs in future years," Hussey said. "I'll point out that we are proposing to borrow $37 million again in 2025 to cover the cost of the project portfolio."

Hussey ran through more drivers of the cost increase, including a cost-of-living adjustment for its Market Monitoring Unit. Salary and benefits are also increasing between 4 and 6%, with 19 new staff positions being added, primarily to work on FERC orders 2023 and 1920 compliance and the Coordinated Grid Planning Process.

"We always have to keep in mind that we maintain our salaries as competitive as compared to the market and as best we can limit inequities between certain positions that we have here at the ISO that should be placed in similar levels," Hussey said.

One stakeholder asked whether the budget was based on full staffing or the expected vacancy rate for NYISO. Hussey said that the vacancy rate was expected to be around 6% and that the budget was based on that lower number. She explained that NYISO was balancing its staffing needs against normal churn and imperfect replacement of departing employees.

The final big line item was computer services. NYISO projects it will spend $3.9 million on computer services, up $1.5 million from the previous year. This is primarily for upgrades, enterprise software subscription costs and increased Amazon Web Services costs.

Forecasts Through 2029

Max Schuler, an economic analyst for NYISO, presented the RS1 *forecast* through 2029.

The RS1 rate is based on net load, billable exports, wheel-throughs and incremental supply. NYISO anticipates increased load driven by large load interconnections, electric vehicles, heating electrification and general economic growth.

"Another important factor is the weather, which is most significant during the winter months for the exports and general system conditions and balance with external control areas," said Schuler, while also noting that climate change is expected to lead to increased net load because of warmer weather in the summer.

Schuler said that by 2029, the total throughput is expected to reach 159,400 GWh. Balancing the expected increases in net load are increased behind-the-meter solar, energy efficiency and billable exports. BTM solar and EE are forecasted to cut RS1 by 0.6 and 1.3%/year, respectively.

Net load is forecasted to dip slightly in 2025 to 147,850 GWh from this year's estimate of 148,580 GWh. After next year, NYISO thinks that the net load will gradually increase to 152,320 GWh by 2029.

Next Steps

The Board of Directors will review a "high-level" summary of the draft budget at its meeting Sept. 17, with the Management Committee reviewing it at its meeting Sept. 25.

Following more Budget and Priorities Working Group meetings, the MC is expected to vote on the budget Oct. 31 and the board Nov. 19. ■

NYISO News

NYISO Operating Committee Briefs

Expedited Delivery, Interconnection Studies

The NYISO Operating Committee on Sept. 12 approved *revisions* to the 2024-01 Expedited Delivery *Study*, which found that all nine proposed projects are deliverable at their requested capacity resource interconnection service (CRIS) levels without additional upgrades.

The OC also approved the interconnection impact study *scopes* for the Niagara Digital Campus and Project Sycamore Orangeburg.

Niagara Digital is a 140-MW data center in *Niagara Falls*. Project Sycamore is a non-curtailable financial services server looking to expand its load to a maximum of 31.8 MW.

The Monticello Hills Wind interconnection study report was approved by the committee. The study found that the 31.5-MW Oswego County wind farm would not have an adverse impact on the grid. The interconnection cost would be approximately $3.4 million.

Operations Report

Aaron Markham, NYISO vice president of operations, presented the August operations *report* to the committee.

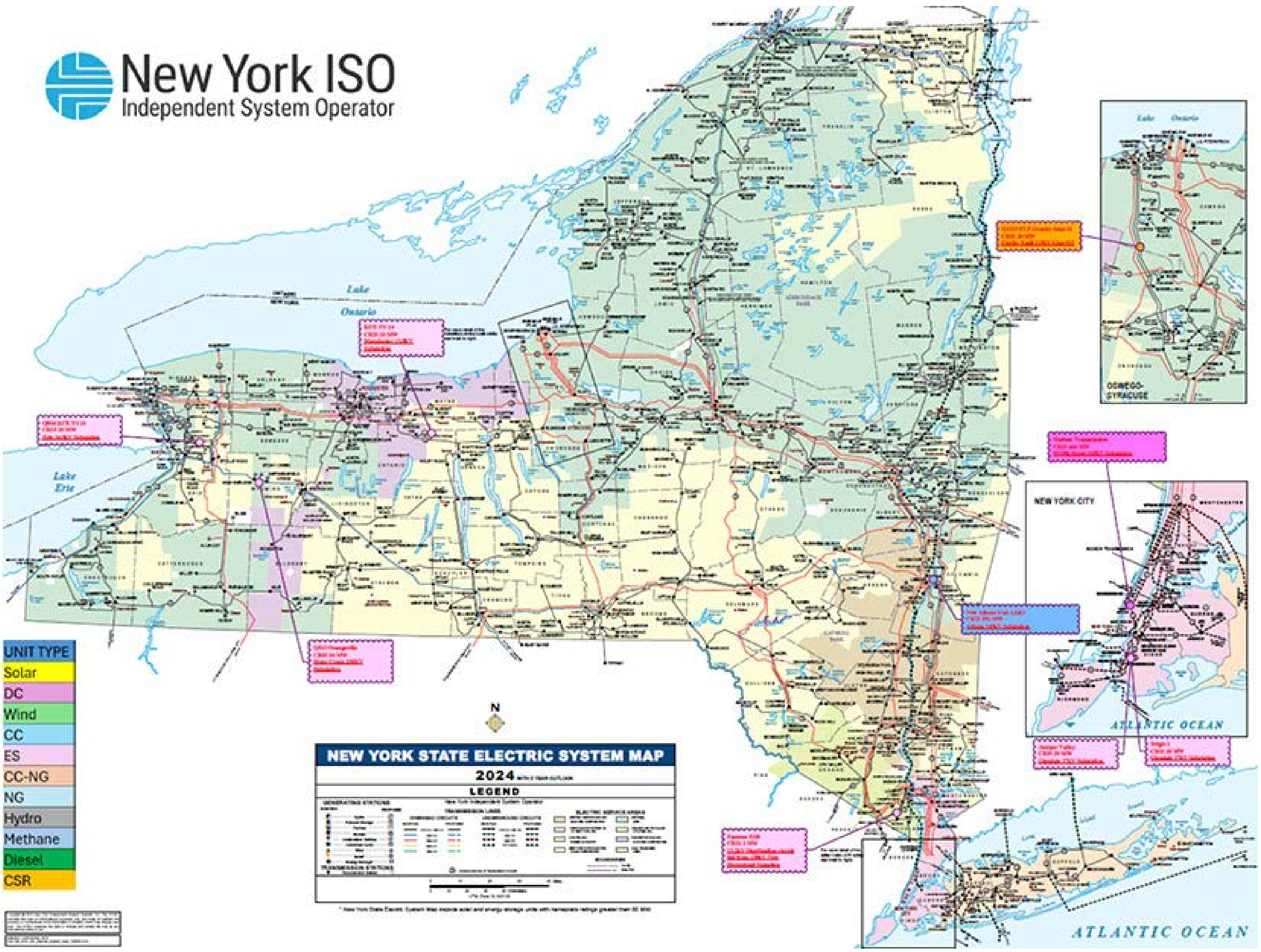
Markham said August's peak load was 28,444 MW, which occurred on the first of the month. He said this was because the month started hot, but the heat quickly tapered off.

"Now that we're in mid-September looking at our longer-range forecasts, it looks like our summer peak was July 8 at 28,990 MW," Markham said.

Markham pointed out emergency demand response and special-case resources had been activated in all zones across New York on Aug. 1 because of the hot weather. Additionally, 31 hours of Thunderstorm Alerts were declared.

"The only other thing of note is that we did increase the behind-the-meter solar nameplate capacity about 65 MW from last month; all other nameplate values repeat the same," he said. ■

— Vincent Gabrielle



Expedited deliverability study 2024-01 members | *NYISO*

PJM News

PJM Stakeholders Discuss DR Winter Availability

By Devin Leith-Yessian

A PJM Market Implementation Committee discussion on expanding the demand response (DR) winter availability window to include a wider range of hours branched off into a broader conversation on how the resource class participates in the RTO's capacity market.

Presenting on behalf of a coalition of demand response providers during the Sept. 11 meeting, Bruce Campbell, principal of Campbell Energy Advisors, said there is excess curtailment capability in the winter that is not being captured in the revised risk modeling and accreditation methodology implemented this year. The coalition includes the Advanced Energy Management Alliance (AEMA), the PJM Industrial Customer Coalition (PJM ICC), CPower, Enel and NRG Curtailment Solutions. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

Drafted through the critical issues fast path (CIFP) stakeholder process conducted last year and approved by FERC in January, the changes shifted the bulk of reliability risk from summer to winter. The summer risk was also concentrated in a few mid-day hours, whereas the risk PJM has identified in the winter is more evenly spread across the day. Campbell said around 20% of the winter reliability risk is in hours not captured in the DR availability window, which is 6 a.m. to 9 p.m.

Paired with the "legacy" availability window, Campbell said the changes led to a significant derate in the amount of capacity DR resources can offer. The amount of DR offered into the 2025/26 Base Residual Auction (BRA), while unchanged in ICAP terms, was around 1,300 MW UCAP lower due to the changes, an amount he estimated could have pushed the auction clearing price down to $210/MW-day, rather than the $269.92/MW-day price posted on July 30. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

In previous MIC discussions, Kerinia Cusick, president of the Center for Renewables Integration, representing Voltus, said PJM is also hampering the potential of load that can offer higher curtailment in the winter by capping capability at the lesser of winter peak load (WPL) or peak load contribution (PLC). She said that effectively limits winter curtailment by the lesser of the estimated potential in winter and summer.

Cusick argued that PJM's effective load carrying capability (ELCC) methodology further limits DR accreditation by assuming that the resource class's available curtailment is proportional to the system load being simulated against the peak load forecast. She said that approach reduces the incentive for consumers with load that is steady year-round to participate in DR programs and results in "double capping" in the winter when capability is limited to WPL and PLC.

Monitoring Analytics President Joe Bowring | © *RTO Insider LLC*

Monitor Argues for New Definition of DR Performance Before Changes

Independent Market Monitor Joe Bowring said PJM must make changes to how performance is defined for DR before the resource's availability window should be expanded. He said the current market design is flawed by not requiring DR resources to reduce their consumption during an emergency, instead mandating that they maintain their load at or below their firm service level (FSL).

"While DR providers argue for a higher ELCC value, they ignore the fact that DR's ELCC is based on assumed perfect performance, unlike thermal resources whose ELCC is based on actual performance during identified winter peak hours. DR ELCC should be based on performance data during the same winter peak hours, like other resources. If that were done, it is likely that the ELCC for DR would be much lower than it is, rather than the increase proposed by the DR providers," Bowring said.

Presenting data from the December 2022 Winter Storm Elliott, he said many industrial DR participants were already offline or had reduced their consumption ahead of the Christmas holiday. When called upon during the performance assessment intervals (PAIs) seen on Dec. 23, he said 83% of resources were already at or below their WPL, a figure that increased to 90% when additional PAIs were declared the following day.

The low starting point for DR load during Elliott was a key factor in the low reduction in load provided by DR resources compared to their expected reduction, which is based on the energy load reductions estimates that DR providers submit to PJM in real-time. Those estimates are derived from a baseline set by recent load on similar hours and days.

Bowring said that while those reduction estimates are used by PJM to get a sense of the amount of DR that could be available ahead of potential PAIs, they do not factor into capacity performance (CP) penalties assessed against resources that fail to deliver load reductions. Instead, CP penalties are assessed against DR resources that maintain a load above their FSL.

Campbell said the sector has made improvements to the load reduction estimates provided to PJM over the past year.

In an interview, Bowring told *RTO Insider* he thinks PJM should redefine what a DR resource is providing to require an explicit

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reduction in load, rather than an expectation that a resource will be below its FSL. He called for the RTO to open a separate stakeholder process to reevaluate how DR participates in the capacity market.

Bowring drew a distinction between the redesign he is seeking for DR participation versus the stakeholder adoption of a Monitor proposal to eliminate energy efficiency (EE) from the capacity construct. While the latter was also initiated by PJM as a broad reconsideration of the role EE should play, Bowring argued that EE does not provide a reliability benefit for consumers and has no place in the Reliability Pricing Model. With the right market design, he said, DR could provide dependable reductions in load when called upon.

"It's not like EE — DR is a resource," Bowring said. "And while it should be on the demand side, if everyone insists on keeping some of it on the supply side it should be demonstrated that it's providing an incremental benefit to PJM."

Energy efficiency providers disputed Bowring's characterization of the resource's value, arguing that capacity market revenues are used to incentivize the purchasing of more efficient devices, pushing the need for capacity lower. PJM filed governing document revisions with FERC that would eliminate EE on Sept. 6. (See *PJM Asks FERC to Eliminate Energy Efficiency from Capacity Market*.)

Bowring said his preference is for the DR to be shifted to the demand side of the market, to be compensated for a year-round reduction in peak loads with a corresponding diminished capacity bill. If stakeholders prefer for DR to remain on the supply side, he said it should be accredited through the same marginal ELCC approach applied to generators, evaluation of performance during emergencies should be based on metered reductions in electric consumption and precise participant locations should be known to PJM for nodal deployment.

"The DR approach in PJM is badly flawed. We believe that DR is an important resource, but to capture its potential, it has to be dealt with in a way that's consistent with how PJM markets work. It has to be nodal, it has to be metered, it has to be verifiable ... based on metered reductions, not on artificially made-up assumptions," Bowring said.

Calpine's David "Scarp" Scarpignato said metering the reduction a DR resource provides runs into challenges for longer deployments, where determining the reduction provided requires determining what the load would have been if the resource was not called on. He said if a resource was committed at 10 a.m., the reduction would be apparent for the initial intervals, but assessing performance at noon or 4 p.m. would rely on counterfactuals.

Cusick said DR is designed to be a planning product that provides a capacity reduction that can avoid the need for construction of new generation resources just to serve a few hours annually. She said Bowring's vision would treat DR as both a capacity resource and energy product at once.

"That is precisely the point. All capacity resources have a must-offer obligation in the energy market," Bowring said. "Capacity by itself is not an actual product. Capacity resources are paid in order to provide a reliable source of energy. The suggestion that DR should be exempt from the obligations of a capacity resource mean that, in that view, DR should not be a capacity resource." ■

PJM News

PJM OC Briefs

PJM Conducts Voltage-reduction Test

VALLEY FORGE, Pa. — The first biennial test of voltage-reduction capability was a success, PJM told the Operating Committee during its Sept. 12 meeting.

Senior Dispatch Manager Kevin Hatch *said* the Mid-Atlantic region saw a 280-MW load reduction during its Aug. 14 test, coming out to about a 0.7% reduction in real-time load. PJM's expectation was about 635 MW (1.6%).

The western and southern regions were tested the following day, together achieving a 360-MW (0.85%) load reduction against a 920-MW (2.2%) expectation. Hatch called the test a "good, coordinated drill."

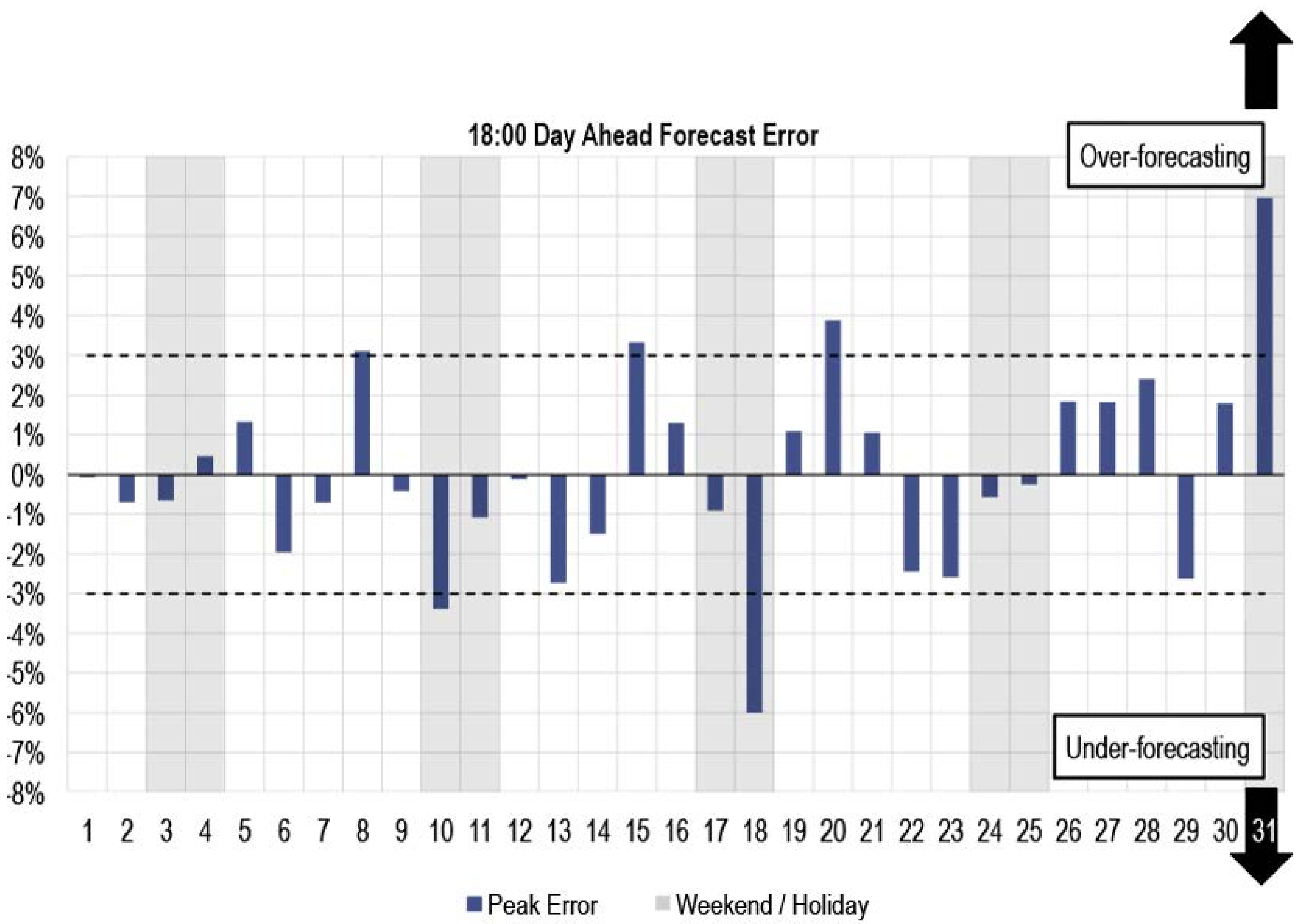
Conducting regular voltage-reduction testing was one of the recommendations following the December 2022 winter storm, during which an alert was issued stating that a reduction could be imminent. Following the storm, PJM told stakeholders that had a handful of additional generators tripped offline, a voltage-reduction action may have been necessary. The last time that happened was in January 2014, during the polar vortex event. (See *PJM Recounts Emergency Conditions, Actions in Elliott Report*.)

A PJM news *release* regarding the test stated that no impact to consumers was reported, and the test provided the RTO and transmission owners valuable insight into how voltage actions are conducted.

"Overall, the tests allowed PJM and its transmission owners to benefit from increased communication and understanding about the time to implement the voltage-reduction test, coordination with field personnel and evaluating the impact on the overall system," PJM wrote. "The test also provided an opportunity to validate the operation of transmission and distribution equipment and verify equipment operating characteristics and parameters."

Generators experienced a 1.5% drop in reactive power capability during the test, which PJM said demonstrates a need for increasing reactive reserves to ensure transfer capability remains available. The loss amounted to 3,150 MVAr in the Mid-Atlantic and 1,300 MVAr in the west and south.

Exelon's Alex Stern said the operational performance data presented at the OC this month supported that PJM's grid is delivering reliability, but stakeholders need to be proactive in ensuring that can be maintained.



PJM presented the monthly operating metrics for August 2024, which it said saw strong performance through heat waves in the beginning of the month with a high over-forecast on Aug. 31. | *PJM*

"To me this data corroborates some of what we heard [PJM CEO Manu Asthana] talk about, which is we have a really reliable grid; we just need the generation to be there, and we need to make sure we send the signals that will get the generation built ... but the grid itself is functioning well," Stern said.

Monthly Operations Metrics

PJM's Marcus Smith *said* load forecasts remained accurate through heat waves at the start of August, including a 149-GW peak on Aug. 1, though unexpectedly low temperatures during the Labor Day holiday weekend contributed to a 7% overforecast on the last day of the month.

Most of PJM's forecast error is driven by weather, particularly temperature, cloud cover and thunderstorms. In response to stakeholder inquiries, Smith said the RTO will look at also presenting its backcasts of how significant of a factor weather has played.

August also saw three spin events, one of which exceeded the 10-minute mark that triggers penalties for underperforming resources. The Aug. 18 event began at 4:04 p.m. and went through 4:20 — 15 minutes and 51 seconds. A total of 1,417 MW of generation and 529 MW of demand response was committed to respond to the event, with respective response rates of 59 and 90%. A total of 630 MW of reserves face penalties for underperformance during the event.

PJM also declared a nine-minute, 39-second spin event Aug. 12, with 1,386 MW committed and a response rate of 75%; and a four-minute, 13-second event Aug. 26, with 2,650 MW committed and a 92% response rate.

PJM's David Kimmel said the response rate has been low recently, which can be attributed to generation start times, as well as some resources having difficulty maintaining their committed output for the duration of the event.

A maximum generation alert was also issued Aug. 27 because of a 9.7% generation outage rate, peaking at 17,611 MW offline, and a high load forecast. Hatch said the alert was meant to put neighboring regions on notice that interchange may have to be curtailed to serve internal load. He said both MISO and SPP were operating tightly ahead of the notice and implemented load-management procedures that reduced the need for interchange.

Cybersecurity Briefing

Presenting the monthly security *briefing*, PJM Director of Enterprise Information Security Jim Gluck recommended that members ensure they have a plan for alerting the RTO to any cybersecurity breaches so staff are aware of any disruptions to expect and precautions that may be necessary to protect the grid.

The concern stemmed from a breach at Halliburton in which customers were notified of disruptions to oilfield operations through news reports, rather than by the company. Gluck said PJM has procedures in the manuals to notify members of any breaches on its end, and sensitive information that may need to be shared can be done so through the Electricity Information Sharing and Analysis Center.

2025 Preliminary Project Budget

PJM's Jim Snow *presented* the preliminary 2025 project budget, which calls for $50 million in capital expenditures, including "historic" investments in technology.

The forecast budget for 2024 is $44 million, while $40 million was spent in 2023 and $38 million the year prior.

The largest share of the budget is $21 million for application replacements and retrofits, the largest of which are the energy management system (EMS) and model management software. Part of the increased funding request is the result of PJM identifying an off-the-shelf product that can accomplish much of the second phase of replacing its EMS software, leading expenditures to be concentrated in 2025 rather than spread out as planned.

The second-largest funding area is current applications and system reliability at $18 million, including upgrades to PJM's Dispatcher Application and Reporting Tool (DART), data analytics, credit and risk enhancements, and cybersecurity measures. The budget proposal also calls for $8 million in funding for facilities and technology infrastructure, $2 million for new products and services, and $1 million on interregional coordination.

Snow said several items were considered for inclusion in the budget, but staff feel comfortable deferring action to avoid a larger spending increase in 2025. That includes spending approximately half a million on developing energy market incentives supporting reserve certainty and about $400,000 on expanding credit surveillance of market participants.

The Finance Committee is scheduled to deliver a recommendation letter to the Board of Managers on Sept. 23, with board action on the budget expected in October. ■

— Devin Leith-Yessian

PJM News

PJM MIC Briefs

Price Cap Increases in 2026/2027 BRA Planning Parameters

VALLEY FORGE, Pa. — PJM *presented* on how the planning parameters for the 2026/27 Base Residual Auction (BRA) affected the variable resource rate (VRR) curve, which intersects with supply and demand to determine auction clearing prices.

The curve is taking a more linear and steep shape in this auction, with the RTO-wide price cap increasing to $696/MW-day should 145,774 MW or less clear the auction. Point B, set at net cost of new entry (CONE), quickly falls to a $0 clearing price at 149,455 MW capacity clearing and remains at zero through to Point C at 153,873 MW.

The planning parameter posting comes weeks after the completion of the 2025/26 BRA and as stakeholders digest a significant jump in clearing prices, including two regions clearing at their price caps. (See *PJM Market Participants React to Spike in Capacity Prices*.)

Scheduled for December 2024, the 2026/27 auction will be the first to use a combined cycle generator as the reference resource (RR), which is the generation class for which the CONE estimates construction costs. Estimated net revenues for the RR and CONE values both are higher for CC generators than the combustion turbines previously used as the reference, steepening the curve and setting the maximum price higher.

The formulas defining the points along the VRR curve were also changed over the previous auction, with Point A now set at the greater of gross CONE or net CONE times 1.75, whereas the point was previously gross or net CONE times 1.5. The reliability requirement multiplier for each point was also changed.

AEP Energy Director of RTO Operations Brock Ondayko questioned whether auction design changes were intended to result in a 3,500-MW difference between clearing at the price cap or at zero.

"It's not going to take much from allowing capacity resources to have some type or revenue to having them have zero revenues," he said.

Market Monitor Joe Bowring said the use of gross CONE to set the maximum price on the VRR curve means that prices could reach approximately $700 per MW-day but that there is no logical or economic basis for capacity market prices at that level.

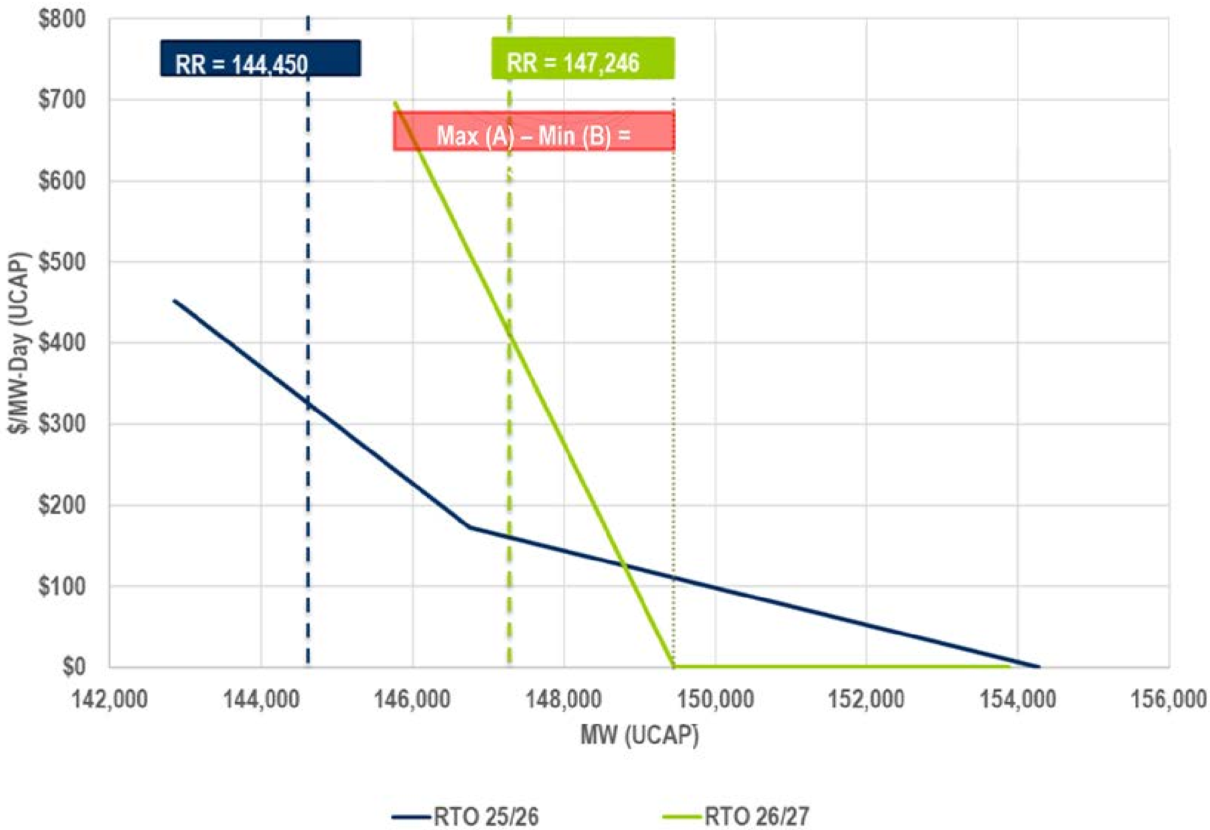
PJM's Pete Langbein said the changes were drafted through the quadrennial review process by both stakeholders and PJM.

PJM Proposes Rules for Non-inverter Hybrid Resources

PJM *presented* its proposal for how non-inverter resources paired with battery storage can participate in its markets as a hybrid resource, such as a gas generator paired with storage.

The effort is the third phase in PJM's development of hybrid market rules, with the first focused on solar and storage and the second looking at all inverter-based resources. While the hybrid model allows for different inverter-based generation types to be combined without storage, the non-inverter option requires generation and storage components.

Both inverter and non-inverter hybrids with



A PJM graphic compares the variable resource rate (VRR) curve for the 2026/27 capacity auction with the year prior. | *PJM*

PJM News

storage would be able to provide reserves — except for non-synchronized and secondary reserve products — and be required to do so if committed in the capacity market. Generation-only hybrids would not be able to provide reserves unless granted an exception.

The make-whole and lost opportunity cost (LOC) design would be similar to the pumped-hydro rules, allowing make-whole payments for hybrids instructed to charge at a higher cost than their desired LMP, while hybrids reducing charging according to manual PJM dispatch would not be eligible for LOC payments.

The changes include several clarifications of existing market rules, including that non-inverter hybrids can provide regulation but, like inverter-based hybrids, they cannot only provide regulation. It also differentiates between station power and the storage charging mode, which must be reported to PJM separately through Power Meter.

The proposal would also clarify how generation-only inverter hybrids are subject to the must-offer requirement. The resource would be required to offer an economic maximum (EcoMax) value into the day-ahead market equal to or greater than its hourly forecast. For inverter hybrids with storage, the energy offered over 24 hours must add up to forecast generation, "grossed up" with the efficiency of the storage.

Non-inverter resources would participate in the energy and ancillary service markets similarly to the standalone storage model.

PJM's Maria Belenky said staff have received inquiries regarding the number of existing resources that would be subject to the non-inverter hybrid rules, but PJM does not yet have a total that can be shared.

PJM Proposal Would Allow Changes to RPM Auction Deadlines

Stakeholders reacted sharply to a PJM *problem statement* and *issue charge* that would consider revising governing documents to add language saying that BRA deadlines are subject to change and the posting of planning parameters does not carry legal consequence.

The issue charge states that the notice would allow PJM to make "potential corrections to capacity market rules that are filed in advance of the commencement of the relevant auction window."

PJM Associate General Counsel Chen Lu said the changes are being contemplated in response to the 3rd U.S. Circuit Court of Appeals vacating a FERC order allowing PJM to revise the locational deliverability area (LDA) reliability requirement for the DPL-S region in the 2024/25 BRA. The court determined that making such a change so far into the auction process would violate the filed rate doctrine. (See *Following Court Ruling, FERC Reluctantly Reverses PJM Post-BRA Change*.)

Adrien Ford, Constellation's director of wholesale market development, said the expected deliverables listed in the issue charge seem overly prescriptive and would guide stakeholders towards a predetermined outcome. She also argued more language should be added around how far in advance any change in auction deadlines would have to be noticed.

Vitol's Jason Barker said market participants need certainty around rules, and it would be imprudent to establish a paradigm where PJM can make after-the-fact rule changes in market design that mandates participation. Instead, he said, the RTO should bring concerns that arise after commencement of mandatory pre-auction activity to stakeholders and FERC for review.

Bowring said the proposal would give PJM unprecedented and inappropriate discretion over deadlines, including those related to the Monitor's responsibilities as well as deadlines for market participants and PJM itself. In addition, he said, the suggestion that market participants cannot rely on the parameters posted by PJM is not consistent with transparency and efficient markets.

External Resource Capacity Clearing

The North Carolina Electric Membership Corp. (NCEMC) presented a *problem statement* and *issue charge* focused on how PJM accounts for external, pseudo-tied capacity resources outside the RTO's footprint which are being committed to serve a load-serving entity.

The documents say the utility is focused on three areas: recognizing when there is a direct transmission path between external generation and LSE load; reflecting the LDA price in the region the external generation is serving in how the resource is compensated; and including that generation in LSE self-supply obligations.

When modeling and clearing capacity resources, the problem statement says, external generation is not assigned to a specific LDA, even when there is a direct path between the unit and an internal region. However, PJM does assign those resources to an LDA to assess Capacity Performance (CP) penalties or bonuses for over- or underperformance during emergencies. The practice of ensuring deliverability to the rest-of-RTO, but not to an LDA, is not reflected in the manual language.

"There is an opportunity to review certain existing provisions pertaining to external capacity resources to determine if there are modifications that would better align the external capacity resource transmission pathway with external capacity resource LDA modeling, the applicable sink LDA used in RPM clearing, and resource performance obligations and mapping. Such mismatches are particularly harmful to Load Serving Entities self-supplying resources to serve load," the problem statement reads.

Calpine's David "Scarp" Scarpignato said it might be prudent to also consider the interaction with the stop-loss limit to CP penalties, noting that PJM has changed the annual limit to penalties that can be assessed against a generator to be based on auction clearing prices, rather than the CONE parameter. For major emergencies, the stop-loss limit can be a more significant factor than the penalty rate for individual performance assessment intervals, he argued. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

Bowring said the Monitor has also said there is a mismatch between external resources getting rest-of-RTO pricing, regardless of the actual electrical path it takes to be delivered to PJM.

Other Committee Activities

- Stakeholders endorsed by acclamation *revisions* to Manual 15: Cost Development Guidelines drafted through the document's periodic review. The changes focus on correcting formulas and updating section numbers. The alterations also remove a table displaying variable operations and maintenance costs, which PJM said could give a false impression that the values are fixed in the manual language; the values are updated annually and posted to its website. (See "First Reads on Several Manual Revision Packages," *PJM MRC/MC Briefs: Aug. 21, 2024*.)
- The committee endorsed by acclamation a quick fix *proposal* brought by PJM to eliminate the high/low and marginal cost proxy interface pricing options. PJM's Phil D'Antonio said they have not been used since the dynamic schedule agreement with Duke Energy Progress was terminated in 2019. (See "PJM Proposes Elimination of 2 Interface Pricing Options," *PJM MIC Briefs: Aug. 7, 2024*.) ■

— Devin Leith-Yessian

PJM News

PJM PC/TEAC Briefs

VALLEY FORGE, Pa. — The PJM Planning Committee and Transmission Expansion Advisory Committee meetings were originally scheduled for Sept. 10 but were rescheduled to Sept. 12 and 13, respectively.

Planning Committee

Voting on CIR Transfer Proposals Deferred to October

The PC on Sept. 12 voted to defer action on three proposals to rework the RTO's process for transferring capacity interconnection rights (CIRs) from a deactivating generator to a new resource. The committee will vote on them at its next meeting, currently scheduled for Oct. 8.

Each of the packages is aimed at creating an expedited process to shift the transmission capability underlying the CIRs of a retiring unit to support the interconnection of a new resource. Proponents of the concept say it could alleviate the need for costly reliability-must-run (RMR) contracts to keep resources online while upgrades are made to the grid to preempt any transmission violations prompted by removing a generator.

The vote was delayed after the committee rejected an amendment to a *proposal* sponsored by Elevate Renewable Energy and the East Kentucky Power Cooperative. (See "Elevate Reviews CIR Transfer Proposal," *PJM PC/TEAC Briefs: July 9, 2024*.)

The amendment, proposed by MN8 Energy, would have added thermal violation analysis to the studies to be conducted on projects seeking CIR transfers and expedited interconnection. MN8 had withdrawn its own *package* ahead of the meeting and thrown its support behind the Elevate-EKPC coalition.

The MN8 amendment would have required thermal studies on the peak and off-peak deliverability cases, but Elevate's Tonja Wicks said the coalition could only accept studies on the off-peak case.

The issue of thermal studies gets to the heart of whether storage resources should be eligible for CIR transfers, with PJM arguing that the capability to charge off the grid could pose "material adverse impacts" not envisioned by the original interconnection studies conducted on the deactivating generator. The PJM *proposal* would outright disqualify storage and open-loop hybrids, whereas both the coalition and Independent Market Monitor packages would allow all resource classes to participate.

PJM's Ed Franks presents the RTO's CIR transfer proposal to stakeholders. | © RTO Insider LLC

Coalition supporters argued storage is one of the best-suited resources for replacing deactivations owing to its quick installation time, minimal footprint and minimal environmental restrictions. Alternatives like renewable generation can require too much land to be viable for replacements in urban settings, such as the retiring Brandon Shores generator outside Baltimore, and the timeline for new nuclear is too lengthy to be suitable, they said.

The material adverse impact standard would also preclude many CIR transfers to resources with a different fuel type, PJM's Ed Franks said. Any projects requiring network upgrades would be removed from the expedited process and moved to the general interconnection queue.

Both the PJM and coalition proposals would only allow CIR transfers to resources seeking to site at the same point of interconnection (POI) as the deactivating unit. The voltage would also be required to be the same, though the interconnection could be at a different breaker.

The coalition proposal comes with a nine-month time frame for most projects to get through the expedited process, with 60 days for initial application review, 180 days for a replacement impact study looking at any potential transmission violations and 30 days for the interconnection service agreement to be approved. Projects with minor network upgrades required would take an additional 90 days.

It would also allow the transfer process to begin before an official deactivation notice has been filed with PJM, allowing discussions between market participants and the RTO's study process to begin quicker. PJM's proposal would require an official notice before CIRs transfers could be initiated.

Interconnection studies on expedited projects would be conducted in parallel with Phase 2 studies being conducted on the contemporaneous cluster in the transitional cycle. PJM's proposal would also place expedited studies at the second phase of the current cluster.

Franks said moving new CIR transfer requests up to be studied with the current cluster is one of the defining features of the packages. While the status quo does allow transfers, only submissions made before the start of the transition to the cluster-based process were sorted into either Transitional Cycle 1 or 2. Later requests must wait until the end of the transitional cycle to be studied as part of TC 1, which is not scheduled to begin reviewing applications until 2026. Franks said the proposals would also result in some cost savings over the status quo even after the transition is complete.

The Monitor's *proposal* would break with the concept of bilaterally transferring CIRs to instead create a PJM-administered process when a deactivation study identifies transmission violations. The RTO would evaluate projects in the queue for any that could use existing headroom to resolve the violations, prioritizing those that could do so with a balance of speed and affordability. Generation developers would also be able to propose alterations to their projects or entirely new resources to meet the need. (See "Monitor Presents CIR Transfer Proposal," *PJM PC/TEAC Briefs: Aug. 6, 2024*.)

"CIRs should go back in the pool and PJM should in a parallel have an expedited process in its control to move forward with any project that can solve the reliability problem," Monitor Joe Bowring said. He argued that the coalition proposal would grant existing generators mar-

PJM News

ket power through their ownership of CIRs, while the Monitor proposes that CIRs end on the date of unit retirement.

Bowring also argued that putting the transfer of headroom under PJM's control ensures that resources receiving CIRs are oriented toward resolving the transmission violations. It would also enable projects sited at different POIs to be expedited, including those that would require network upgrades. If no project in the queue addressed the identified reliability issue, PJM would run an auction for proposals to build new generation to address the reliability issue within a defined period of time.

If no transmission violations are associated with a deactivation, the CIRs would be made available to projects in the general queue cycles according to their cluster position. The same would be true of any CIRs not allocated through the expedited process. Bowring argued that the value behind interconnection rights is derived from the sum total of transmission investments across PJM and thus should not be considered the property rights of developers who paid for network upgrades as part of a generation interconnection.

"CIRs are a network resource, are essential to FERC-mandated open access, and derive their value from all the investments made by customers and generators over a long period," Bowring said.

Stakeholders Endorse Manual 14F Periodic Revisions

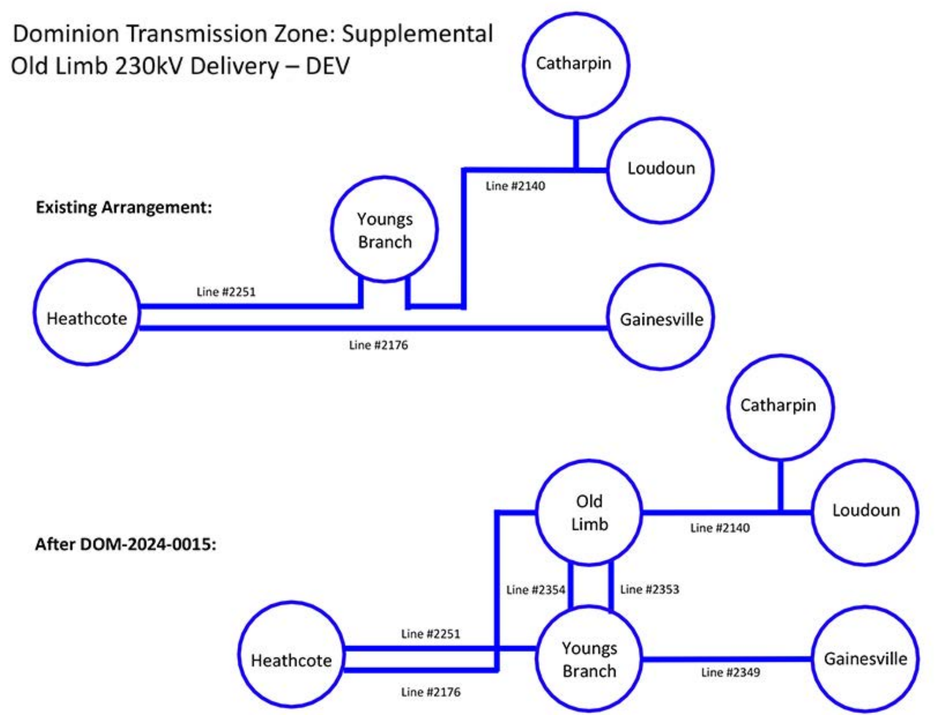
The committee endorsed a set of *revisions* to Manual 14F: Competitive Planning Process that remove out-of-date references and update details in the document.

PJM's Brian Lynn said the changes were identified during PJM's Long-term Regional Transmission Planning (LTRTP) workshops but were not adopted as the overall LTRTP changes were not voted on. Stakeholder focus has shifted to revising long-term planning through PJM's compliance filing on FERC Order 1920.

First Read on Manual 21B Revisions

PJM's Andrew Gledhill *presented* the first set of proposed revisions to the newly established Manual 21B, which details the rules for capacity resource accreditation. The changes would align the definition of dual-fuel combustion turbine and combined cycle units in the manual with revised Reliability Assurance Agreement definitions accepted by FERC in July (ER24-1988).

The change allows gas generators that are capable of operating on a secondary fuel after starting on their primary fuel to qualify as dual-fuel, a change sought by Calpine earlier this year. During the earlier stakeholder process, Calpine's David "Scarp" Scarpignato said some gas units can start on a small amount of fuel already purchased and packed into the portion of the gas pipeline on generator property, even if the regional pipeline is offline. (See "Quick Fix for Dual-fuel Classification Endorsed," *PJM MRC Briefs: April 25, 2024*.)



Dominion presented the TEAC with a $35 million project to construct a new Old Limb Substation serving a data center complex in Prince William County, Va. | *PJM*

Transmission Expansion Advisory Committee

Supplemental Projects

During the TEAC meeting Sept. 13, FirstEnergy *presented* a $99.1 million project to rebuild its 138-kV New Departure substation to serve a new 540-MVA customer, with a 345-kV delivery point in the ATSI transmission zone.

The three-phased project would begin with adjusting relay settings at the substation, work that is expected to be completed in March 2025, followed by the rebuilding of the 138-kV infrastructure already present at the site. It would be reconfigured as a breaker-and-a-half switching station with nine breakers. The second phase, to be completed in May 2028, also includes cutting New Departure into the 138-kV Nasa-Greenfield and Ford-Greenfield lines. The first two phases together are estimated to cost $27 million.

The $72 million third phase involves building a new 345-kV ring bus at New Departure with four breakers and two 345/138-kV transformers. The facility would be looped into the 345-kV Davis-Besse-Hayes line with two new lines. An additional six 138-kV breakers would also be added to New Departure in the third phase, which FirstEnergy envisions being complete in November 2029.

Exelon *presented* a $92.1 million project to rebuild its 10-mile 230-kV Ryceville-Morgantown line in the PEPCO zone, a line that the utility said is nearing its end of life at 56 years old. The work would include replacing 55 lattice towers with steel monopoles and new conductor. The project is in the engineering phase, with a projected in-service date of April 1, 2028.

Dominion Energy *presented* a $35 million project to construct a new 230-kV Old Limb substation to serve new data center load in its transmission zone. The new facility would be configured with a six-breaker ring arrangement cut into the Heathcote-Gainesville and Loudoun-Youngs Branch lines. Two new 230-kV tie-lines would be constructed between Old Limb and Youngs Branch, the latter of which would have two new breakers and terminal equipment installed. ■

— Devin Leith-Yessian

Southeast

SEEM Opponents Push Back on Supporters' Claims

Organizations Say SEEM Qualifies as Loose Power Pool

By Holden Mann

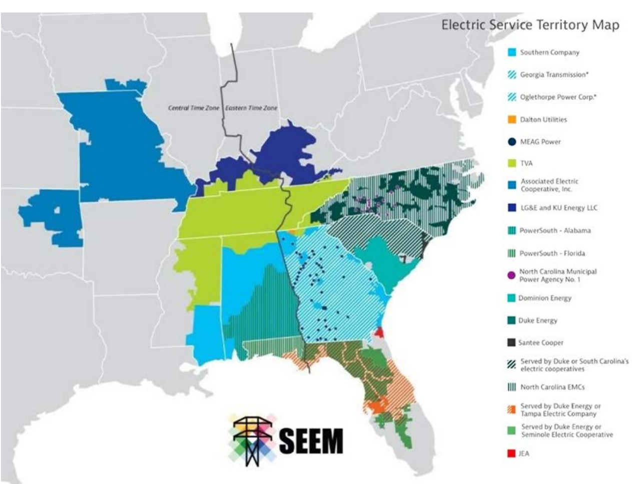
Opponents of the Southeast Energy Exchange Market (SEEM) argued last week that the market does not provide the benefits to customers promised by its supporters and also violates FERC's regulations (*ER21-1111*, et al.).

SEEM's opponents were responding to a filing submitted by SEEM members last month that argued the market brings savings to consumers and should be allowed to continue. (See *SEEM Members Respond to FERC Briefing Request*.)

FERC had requested briefings from both supporters and detractors of SEEM as a step toward satisfying a D.C. Circuit Court of Appeals order last year remanding the commission's approval of the market. (See *FERC Requests Briefings on SEEM After DC Circuit Order*.)

The reply briefs were filed by three groups representing various longstanding opponents of SEEM:

- Public Interest Organizations (PIO) — a group of mostly environmental organizations including the Sierra Club, the Southern Alliance for Clean Energy, the Natural Resources Defense Council and the Partnership for Southern Equity.
- Southern Renewable Energy Association (SREA) — a trade organization promoting renewable energy in seven Southeastern states whose members include National Grid, Invenergy and Ørsted.
- Clean Trades — Advanced Energy United, the Clean Energy Buyers Association and the Solar Energy Industries Association.



The Southeast Energy Exchange Market covers all or parts of 12 states following the addition of territories in Florida last year. | *SEEM*

The commission asked respondents to answer whether SEEM qualifies as a loose power pool under FERC Order 888 and whether the market's requirements that entities transacting in it have a source and sink inside its footprint violate Order 888. SEEM members argued in their brief that the market does not qualify as a loose power pool because "the commission has already found that NFEETS [the market's non-firm energy exchange transmission service] is neither a discount nor a special rate" and that the D.C. Circuit did not find fault with FERC's reasoning on that point.

However, the market's opponents said this argument ignored the clear intent of the court's remand order. The PIOs wrote that SEEM "has walked and quacked like an exclusive power pool" since its conception and criticized the commission and members for focusing "entirely on questions regarding definitional characterizations and technical limitations of SEEM."

"These questions have already been asked and answered in the record and rejected by the court," the PIOs wrote. "By delving deeply into the question of geographic limitations and alternative theories designed to justify SEEM's existing design rather than address its core problems, both the briefing order and the utilities ignore the court's broader concerns that SEEM's overall design violates Order 888's open access requirements."

The PIOs said the D.C. Circuit's ruling was intended to allow FERC, having seen SEEM in action, to reevaluate whether the market actually complies with Order 888. They said that contrary to supporters' promises, "SEEM has demonstrated the need for Order 888's protections" by systematically excluding independent power producers; the organizations claimed "no non-utility sellers have transacted in SEEM [and] just one non-SEEM utility participant" has joined the market.

'Nominal Cost Savings'

Energy sales have been dominated by just a few utilities, the PIOs claimed, citing a *report* from SEEM's market auditor showing that "a single seller accounted for between 30 and almost 80% of all sales" in the market's first few months and the two largest sellers combined accounted for 55 to 90% of sales. The arrival of utilities from Florida in July 2023 lessened this dominance, but the PIOs observed that two sellers alone still account for more than 40% of all sales in each month.

The PIOs said that the lack of competition has resulted in only "nominal cost savings." Sharing this view was SREA, which pointed out that while SEEM proponents originally projected benefits of $40 million annually, the market reported total benefits of $3.7 million in 2023, which "appears to be a gross benefit." Taking estimates for annual non-centralized costs of $2.8 million and payments for legal work, auditing and platform development, SREA estimated an overall net cost of $824,591 per year.

SREA also cited data from the auditor to point out that trading on SEEM virtually shut down during the widespread blackouts arising from winter storms in December 2022, with less than 1,000 MWh traded on the platform between Dec. 23 and Dec. 27. The association also noted 53 hours this July, mostly at night, during which no trades occurred on SEEM at all. SREA quoted the market auditor's report of "a statistically significant relationship" in which high demand is matched with decreased trading activity on SEEM.

Regarding the SEEM members' assertion about NFEETS, the Clean Trades called their description of NFEETS as a pancaked rate a "post-hoc rationalization," noting that members called the service "non-pancaked" when they first filed the SEEM agreement. Now, however, the Clean Trades said that members have called their previous description of NFEETS "shorthand." They called on the commission to recognize the truth of the matter, as they described it, and treat SEEM as a loose power pool.

"The commission should reject the SEEM Members' attempt to have their pancakes and eat them too," the Clean Trades said. "The bottom line is that … SEEM represents a pooling arrangement that favors members over non-members through a 'discounted' rate. It is a textbook example of a 'loose power pool' and must satisfy the associated regulatory strictures." ■

SPP News

MISO, SPP Try Again to Find Joint Seam Projects

By Tom Kleckner

After five fruitless attempts to agree on joint transmission projects across their seams, MISO and SPP will use what they call a "blended joint model" in parallel with existing SPP and MISO regional models.

The RTOs' staffers told stakeholders during a Sept. 9 Interregional Planning Stakeholder Advisory Committee meeting that their Coordinated System Plan (CSP) study, required every two years by a joint operating agreement, will identify near-term upgrades that "incrementally enhance" transfer capability and produce multiple benefits across the two grids. The study will include reliability, economic and transfer analysis using forward-looking models and assumptions (10- and/or 20-year models), they said.

"The hope is that we have some mutually beneficial projects that we can both agree to recommend approval and ultimately share costs and construct," SPP's Clint Savoy said. "That's the way the current process works today, or that's the way it's envisioned in the JOA."

Five previous studies have failed to produce any joint projects over differences in allocating costs. That led the RTOs to try a different approach with the Joint Targeted Interconnection Queue project, which identified a $1.86 billion portfolio of five projects that could support up to 28 GW of interconnecting generation on both sides of the seam. The Department of Energy last year awarded the portfolio $464 million under its Grid Resilience and Innovation Partnerships program. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

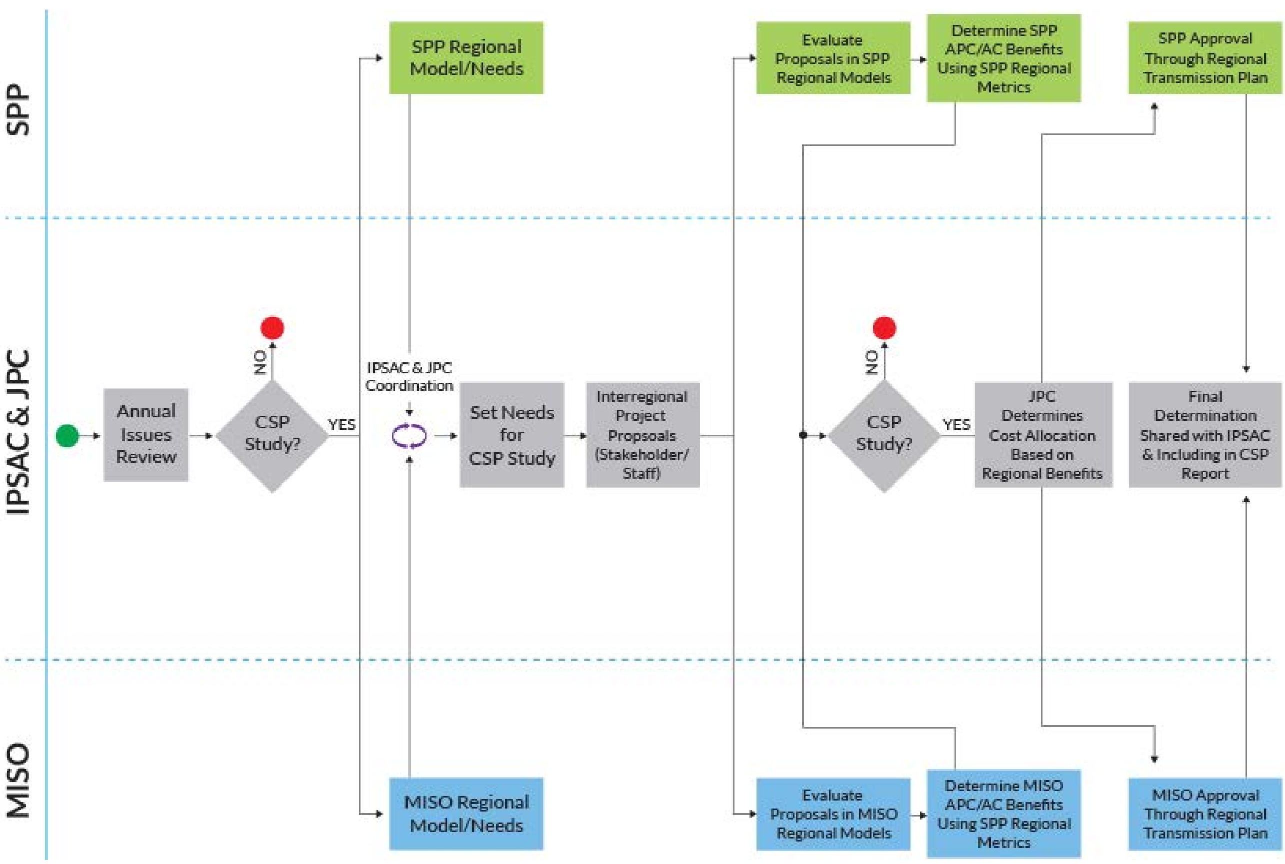
Under the blended model, MISO will use its 2023 *Long-Range Transmission Planning* reliability and economic model sets and SPP will run the 2025 *Integrated Transmission Planning*'s same model sets. Staff will use three of four base seasonal models (winter peak, summer peak, average load and light load).

The RTOs both want a multi-benefit style project type and cost allocation to draw on a broader set of benefits for project recommendations, they said. Savoy said FERC Order 1920, which requires transmission-planning regions use at least a 20-year horizon, has provided something of a guidepost for the RTOs to follow.

"We hope this new approach will let us look into additional drivers for projects other than just economic or reliability benefits, if you will, maybe consider different assumptions as we are developing, the list of needs that we want to fix," he said. "And so what we hope is a better outcome to look more proactively, maybe have a broader set of issues that we're looking for or benefits to consider, rather than just the traditional economic reliability and public policy."

The two staffs will continue to develop the study's scope, incorporating stakeholder feedback, and share it with stakeholders when complete later this year. The 2024 CSP will run through 2025.

The RTOs will have to file a waiver request with FERC requesting permission to use the blended study process. They said they will partner with states and stakeholders to identify and file any needed changes to their JOA and tariffs. ■



MISO's and SPP's blended approach to a coordinated system plan. | *MISO, SPP*

Company Briefs

BP to Sell US Onshore Wind Business

BP last week announced it plans to sell its U.S. onshore wind energy business, saying the assets are not aligned with its growth plans.

BP said it will launch the sale process for the wind assets, bp Wind Energy, which has interests in 10 operating assets across seven states.

The move also comes as BP's new CEO, Murray Auchincloss, has imposed a hiring freeze and paused new offshore wind projects.

More: *Reuters*

Google Signs PPA with X-Elio

Google last week announced a power purchase agreement with Spain-based renewables company X-Elio.

Google will offtake all 128 MW from X-Elio's Bell solar farm in Texas, which will also feature a 100-MW storage system.

The farm is expected to be operational in the second half of 2025.

More: *Renewables Now*

AMS Renewable Energy Acquires Collective Solar

AMS Renewable Energy, a distributed solar and storage engineering, procurement and construction company, last week announced the acquisition of Collective Solar, a distributed generation solar construction firm.

With the acquisition of Collective and its construction platform, AMS will now have the resources to scale design, engineering, logistics, procurement and construction services for its developer and clients.

More: *Solar Power World*

Vistra, Sunrun Partner on Residential Battery Aggregation Program

Vistra last week announced a new program will aggregate power stored in residential, solar-connected batteries, forming a virtual power plant to dispatch energy in times of high demand.

TXU Energy customers who opt into the program and have installed Sunrun solar panels and batteries will receive incentives for their participation. In partnership with TXU Energy, Sunrun will network customers' batteries together and manage the discharging of stored power.

More: *Vistra*

Federal Briefs

EIA: US Power Use to Reach Record Highs in 2024, 2025

U.S. power consumption is on track to rise to new records in 2024 and 2025, according to the EIA.

The administration projected demand will rise to 4.101 terawatt-hours (TWh) in 2024 and 4.185 TWh in 2025. That compares to 4 TWh in 2023 and a record 4.067 TWh in 2022.

More: *Reuters*

Man Pleads Guilty to Shooting Electricity, Pipeline Facilities

Cameron Monte Smith last week pleaded guilty in federal court to two counts of

destruction of an energy facility, with one count each in North Dakota and South Dakota.

Court documents show Smith caused more than $1.2 million in damage by shooting at the Wheelock substation in northwest North Dakota with a high-powered rifle in May 2023. Smith also caused more than $495,000 in damage to a transformer and pump station of the Keystone Pipeline in South Dakota in July 2022.

Smith faces up to 20 years in prison for each count.

More: *South Dakota Searchlight*

Judge Temporarily Blocks Biden Rule to Limit Flaring at Oil Wells

U.S. District Judge Daniel Traynor last week temporarily blocked a new Biden administration rule aimed at reducing the venting and flaring of natural gas at oil wells.

North Dakota, Montana, Texas, Wyoming and Utah challenged the rule earlier this year, arguing it would hinder oil and gas production and that the Bureau of Land Management overstepped its regulatory authority on non-federal minerals and air pollution.

"At this preliminary stage, the plaintiffs have shown they are likely to succeed on the merits of their claim the 2024 rule is arbitrary and capricious," Traynor wrote in his ruling.

More: *The Associated Press*

Northeast news from our other channels

EDF Report Promotes Heat Pumps Over Hydrogen in NY — NetZero Insider

NY OSW: If at First You Don't Succeed, Try, Try Again — NetZero Insider

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

State Briefs

COLORADO

PUC Investigates Xcel over Power Outage Complaints

The Public Utilities Commission last week discussed how to move forward with its investigation of Xcel Energy over the numerous complaints about power outages.

Erin O'Neill, deputy director of fixed utilities for the commission, said there are a lot of unanswered questions about what is causing the outages and how Xcel is responding.

More: *CPR News*

IOWA

Republicans, Sierra Club File Lawsuits Against Summit Pipeline Decision

A group of nearly 40 lawmakers comprising the Republican Legislative Intervenors for Justice, along with the Sierra Club's state chapter, last week said they plan to ask federal and state courts to rule that the Utilities Commission acted illegally and unconstitutionally in its approval of Summit Carbon Solutions' pipeline.

The pipeline "prioritizes corporate interests in tax credits over the safety, property rights and well-being of Iowa's citizens," according to a statement from the lawmakers.

The Utilities Commission approved the application in June, under the conditions that Summit submitted documentation of various regulating requirements and an insurance policy. The $8 billion pipeline project would connect to 57 ethanol plants and stretch across Iowa, Nebraska, Minnesota, South Dakota and North Dakota.

More: *Iowa Capital Dispatch*; *Radio Iowa*

KENTUCKY

Beshear Names Stacy to PSC

Gov. Andy Beshear last week named John Will Stacy, a state representative from 1993 to 2015, to the Public Service Commission.

Stacy was House majority whip serving alongside then-House Speaker Greg Stumbo and then-House Majority Leader Rocky Adkins, who is now a senior adviser to Beshear.

Stacy replaces Kent Chandler, the former chair, after he resigned in June.

More: *Kentucky Lantern*

MONTANA

PSC to Investigate NorthWestern Energy Committee

The Public Service Commission last week voted to open an investigation into NorthWestern Energy's Electric Technical Advisory Committee.

This summer, three renewable energy groups raised questions about whether NorthWestern was legally running the committee, which makes recommendations about resource planning for the future. The groups said NorthWestern was closing its meetings to the public without adequate justification and hadn't chosen members who represent broad interests.

The investigation will allow the PSC to collect information and materials about the committee and post it on its public portal.

More: *Daily Montanan*

NEW YORK

Vestas Secures Empire Wind 1 Project Order

Vestas last week announced it has secured an 810 MW offshore order from Equinor to power the Empire Wind 1 offshore wind project.

The order includes 54 V236-15.0 MW turbines and marks the company's first U.S. order for an offshore platform and this type of turbine.

Turbine delivery is expected to begin in 2026 with completion scheduled for 2027.

More: *North American Windpower*

NORTH CAROLINA

UC Staff Recommends Reducing VEPCO's Proposed Rate Hike

Utilities Commission staff last week recommended a $28.6 million rate increase for Virginia Electric and Power Co. (VEPCO), about half of what the company originally requested.

The recommended increase is premised on a 9.60% ROE, which is 15 points below the utility's currently authorized ROE. It is also significantly below the 10.60% ROE requested by VEPCO.

VEPCO has initially asked for a $56.6 million increase.

More: *S&P Global*

OHIO

FirstEnergy to Pay $100M in HB 6 Settlement with SEC

FirstEnergy last week agreed to pay a $100 million fine to settle civil fraud charges filed by the Securities and Exchange Commission related to the House Bill 6 nuclear power plant bailout scandal.

The utility's former CEO, Charles Jones, will still face charges from the SEC, which is accusing him of misleading investors after former House Speaker Larry Householder was arrested in the $60 million bribery case in 2020.

The SEC fine is significantly higher than FirstEnergy's $20 million settlement with state prosecutors made a month ago.

More: *Statehouse News Bureau*

VIRGINIA

Appalachian Power Requests Reduction to Net-metering Pay Rate

Appalachian Power on Aug. 30 submitted a request to the State Corporation Commission for a 70% reduction in its net-metering pay rate.

Appalachian Power is currently paying participants 16 cents/kWh for the excess power they generate, and wants to grandfather them for 25 years, while offering new participants 4 cents/kWh. For a customer who needs about 1,000 kW and generates 1,057 kW through their panels, the change would result in a monthly bill increase from $7.96 to $66.95.

The commission is expected to review the request over the next 12 months.

More: *Virginia Mercury*

Fairfax County to Regulate Data Center Construction

The Fairfax County Board of Supervisors

last week voted 8-2 to put new restrictions on data centers and where they can be located.

Where the centers are built has been controversial in many parts of the state, including Loudoun and Prince William counties. While Fairfax County has about 3 million square feet of data centers, Loudoun County has more than 30 million.

The new regulations were passed after a four-hour public hearing.

More: *DC News Now*

TEXAS

Golden Pass LNG Requests Extension from FERC

Golden Pass LNG on Aug. 28 requested a three-year extension from FERC to finish construction of its facility near Sabine Pass.

The requested extension would give Golden Pass until Nov. 30, 2029, to finish the project. The request comes after Golden Pass LNG's lead construction contractor, Zachry Holdings, was ordered to exit the project in July in an "efficient and cooperative manner" by a bankruptcy judge.

Golden Pass has already been issued one extension by FERC on Dec. 11, 2019, until Nov. 30, 2026.

More: *Houston Chronicle*