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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: Several balancing authorities in the Eastern U.S. declared energy emergencies during Winter Storm Elliott, with Tennessee Valley Authority, Duke Energy Carolinas (DEC), Duke Energy Progress (DEP) and Louisville Gas and Electric-Kentucky Utilities (LGE-KU) forced to shed firm loads. PJM, Southern, MISO, SPP and ISO-NE also declared emergencies, but avoided load shedding. | *NERC*

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Your Eyes and Ears on the Organized Electric Markets

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Beware of Government-driven Climate Policy

By Kenneth W. Costello

Kenneth W. Costello

Climate change presents a daunting challenge for economists, political scientists and policymakers: It features a global shared resource (namely, the atmosphere) magnified by massive uncertainty over both physical and economic processes; everyone contributes to its cause, and everyone potentially bears the costs of its consequences.

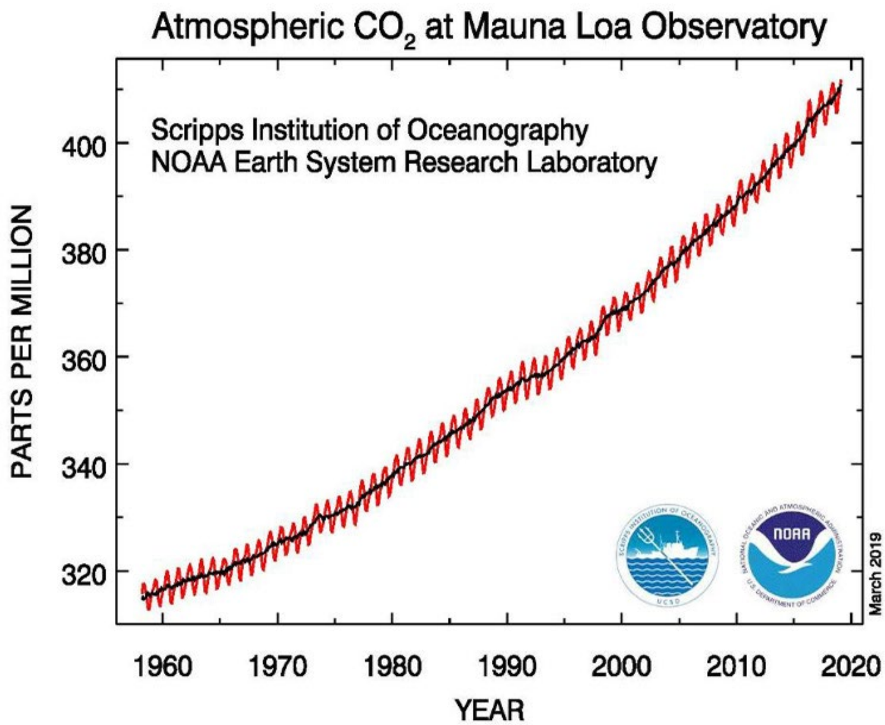
Three policy challenges ensue: (1) taking collective action, where cooperation of countries is essential to achieve targeted reductions in greenhouse gas emissions, (2) incentivizing individuals and businesses to reduce their GHG emissions, and (3) identifying the preferred institutional arrangement — namely, markets versus government — to alleviate the damages from climate change.

A major problem is that when one country benefits from initiating reductions in GHG emissions, other countries also benefit. The reality that controlling climate change in one country cannot deprive others of the benefits motivates individual countries to avoid paying for mitigation, creating the problem of what economists call free ridership.

Since changes in GHG emissions affect the entire world, any successful coordination would require virtual unanimity rather than just coalition building. But as past experience has shown, reaching mutual consent among multiple heterogenous countries is a Herculean task. (How many U.N. Climate Change Conferences have we had? I lost count.)

Policymakers confront the task of trading off the risk of doing too little to combat climate change with excessive spending or regulating. The ideal policy position on climate change depends critically on the size and likelihood of negative outcomes, considering the best available scientific and other fact-based evidence.

Reasonable people can disagree over the cost of an overly active climate strategy versus the cost of a passive one. Disagreement starts with the credibility of the scientific evidence. People may question the sureness of the scientific evidence. They may also have trouble distinguishing scientifically sound evidence from advocacy evidence.



Critics say CO_2 levels have continued to grow despite nearly 30 years of global climate conferences since COP 1 in Berlin in 1995. | *NOAA*

Disagreement may then shift to the relevance of this evidence for public policy. Here, self-interest motives and ideology play key roles. People tend to adhere to their prior beliefs irrespective of the scientific evidence. These beliefs carry over to the relative costs they place on an overly aggressive climate policy relative to an overly passive policy. All of these factors contribute to the difficulty of reaching political consensus.

For example, the preferred strategy depends (among other things) on people's risk aversion to the damage that climate change can cause. Some people may struggle more with an incorrect scientific conclusion that climate change has a high risk when in fact it has a low risk; the opportunity cost is in the form of excessive resources allocated to slowing climate change, which inevitably results in lower economic growth and other social costs.

Climate policy certainly falls into a space where government action could very likely have bad consequences. This is especially true for green subsidies for renewable energy and energy efficiency, which although widely popular likely fails a cost-benefit test.

Subsidies encourage rent seeking by special interests and allow policy makers to determine which technologies to champion. Subsidies for renewable energy have been especially attractive because of their claim to improve air quality and create new jobs, while their costs are concealed in the larger government budget. It is harder to sell the public on, say, a carbon tax whose costs are more visible and concentrated on consumers.

Economists consider subsidies for almost anything to be economically inefficient, usually politically motivated, and lasting too long. Their preference is to have the government reallocate funds for basic research. But, not surprisingly, political forces have given higher priority to existing clean technologies with their strong lobbyists than to potentially future ones.

Rent seeking in the form of exploiting government to gain favors tends to concentrate the benefits to these groups while spreading the costs to the general population. A good example is interest groups pressuring state utility regulators and legislatures to use subsidies funded by utility customers and taxpayers to promote energy efficiency, distributed generation, electric vehicles, and other clean-energy technologies.

Stakeholder Soapbox

This inevitably leads to cost subsidization, which (among other things) is unfair to both utility customers and taxpayers who do not benefit. Unfortunately, the evidence confirms that an increasing number of states have been at the vanguard of bad policies that have inflicted a regressive-tax-type wound on lower income people. The reason is that lower-income households spend a larger percentage of their incomes on electricity, and these policies tend to increase electricity prices. For the electric industry, an obsession with climate change threatens policy objectives long adhered to by state utility regulators.

But isn't it also true that a fixation with climate change, bordering on irrational climate hypochondria, can deprive impoverished people, especially in less-developed countries, of the resources required for survival or progress? This makes little economic sense and reflects the insensitivity to the plight of poor people from those in wealthy countries absorbed with climate change and renewable energy, and the ridding of fossil fuels. Fossil fuels have been a vital factor in the economic growth of less developed countries. There is a serious "equity" problem here.

Relevant to climate action is also the intergenerational issue of whether people today should sacrifice under an aggressive climate policy to benefit people in the far-out future, who are likely to have a much higher standard of living. Some climate activists view anything less than an all-out effort to attack climate change as a social injustice.

In economics, public choice theory predicts that government, composed of bureaucrats and politicians, lacks the necessary information and the right incentives to pursue policies that are in the public good.

We see numerous real-world examples where actual public policies in all areas of society deviate far from what so-called "blackboard economics" would say is ideal. Such divergence typically results from information deficiencies, institutional realities, and the government's incentive to serve its self-interest and appease special interests rather than the public good. Can we then expect any climate policy dominated by interest-group politics to be in the public good? What we have seen up to now says no.

Either for ideological or monetary reasons, climate advocates want to shape future climate policy, and the sooner the better. Their self-interest motive benefits only themselves, not the broader public interest. Their vision of the future entails filling up their pockets (e.g., clean-energy vendors) or satisfying their followed doctrine (e.g., environmentalists). They have relentlessly lobbied politicians and bureaucrats at all levels of government for special favors. This reality by itself warrants nongovernmental options to address climate change.

Given the problems faced by government-driven climate policy — a particular one that I have mentioned is subsidies for clean energy — more attention should focus on measures that strengthen market signals for individuals to adapt to climate change. These measures may include adaptation based on the pricing mechanism, companies satisfying the demands of consumers and investors for clean products, and governmental assistance for basic research in clean-energy technologies (for instance, nuclear power, renewable energy, and hydropower) and climate engineering. Consumers and investors can reveal their preference for financial assets or products and services that explicitly account for climate change. They have done so already, and we should expect this development to proliferate in the future. But, so far, regretfully market-centric approaches have taken a back seat to government-driven climate policies.

We will surely see in the years ahead more political posturing in mitigating climate change. So much talk and money has been expended on government-driven climate policy. What have we gotten out of it? I would say probably very little in terms of global temperature – no more than a rounding error. Don't expect things to improve in the future.

The bottom line: spending a lot of money on climate change with status quo policies will likely have a negative social return. The sooner we realize that, the better off we will be. ■

Kenneth W. Costello is a regulatory economist and independent consultant.

FERC/Federal News

Déjà Vu as FERC, NERC Issue Recommendations over Holiday Outages

Staff Highlights a Near Miss with Consolidated Edison's NYC Natural Gas Utility

James Downing

FERC and NERC staff presented their *initial recommendations* from their joint inquiry into the widespread electric outages last Christmas, which include completing development of winterization standards and improving reliability of natural gas infrastructure.

The report includes 11 recommendations to prevent similar events — the outages were the fifth major reliability incident tied to winter weather in the past 11 years, including Winter Storm Uri in 2021 when much of Texas was without power for days and hundreds died — in the future.

"This is the fifth time in 11 years that we've had a winter-related weather event where we had significant generator losses," FERC Chairman Willie Phillips said. "But this time it was unprecedented: Nearly 90,000 megawatts and nearly 80% of the generating units failed to perform at temperatures above the unit's own documented minimum operating temperature."

As in previous winter events, the natural gas system also suffered, with production from the Marcellus and Utica shale regions falling by as much as 54%, which led to low pipeline pressures that nearly spelled disaster for New York City at the height of winter.

"We're talking about — if pressure does not return — going house to house, apartment to apartment, to relight pilots; just the act of doing this would take months," Phillips said at his post-meeting press conference. "And this event happened in December. A little bit of winter comes through in New York in January and February. It would have been catastrophic. Everyone should be concerned enough to act on this report, and the recommendations when they come out, immediately."

NERC CEO Jim Robb was at the press conference, and he echoed Phillip's concerns about how much a near miss Winter Storm Elliot proved to be.

"We were fortunate in that this was a relatively short-lived cold weather event," Robb said. "And it warmed up on Christmas Day. Had it not, ConEd certainly would have been in the soup. It was also a storm that was centered in [the] western third of the Eastern Interconnection. And if it had been a couple hundred miles further east, New England would have had real catastrophic events."

Robb noted that it took the 2003 Blackout in the Eastern Interconnection to get Congress to approve a mandatory reliability regime.

He said he hoped the prospect of millions of New Yorkers being without heat at the height of winter will produce some action on natural gas reliability.

The report calls on Congress and state legislatures to enact legislation setting up reliability rules for the natural gas systems from the wellhead through the pipeline requiring cold weather preparedness plans, freeze protections plans and operating measures for extreme cold. That legislation should set up regional natural gas communications coordinators like the reliability coordinators for the power system, and it would need to designate critical natural gas infrastructure to be protected from any load shedding that grid operators use in emergencies.

Asked to comment on its near miss, Consolidated Edison pointed to a press release it issued at 6:30 p.m. on Christmas Eve calling for emergency conservation because of problems at pipelines serving New York that it did not own.

"We asked customers to conserve; switched our electric/steam generation plants to alternative fuels and relied on LNG and CNG," said spokesman Allan Drury. "On Christmas morning, our region's temperatures were a bit higher than expected and gas supplies

	2011 Event	2014 Event	2018 Event	2021 Event	2022 Event
Significant levels of incremental unplanned electric generating unit losses with top causes found to be mechanical/electrical, freezing, and fuel issues.	✓	✓	✓	✓	✓
Significant natural gas production decreases occurred, with some areas of the country more severely affected.	✓			✓	✓
Short-range forecasts of peak electricity demands were less than actual demands for some BAs in event area.	✓		✓	✓	✓
Significant natural gas LDC outages or near miss	✓				✓

A chart from FERC and NERC staffs' presentation showing the similarities between the reliability issues caused by winter weather over the past decade plus. | *FERC/NERC*

FERC/Federal News

were adequate."

The company did not respond to a request for comment on the call for gas reliability rules.

The natural gas trade groups did not want to discuss the report, which is preliminary; FERC and NERC plan to release a final report later this fall. But the Interstate Natural Gas Association of America, which represents pipelines, did throw some cold water on the idea of a mandatory reliability regime for the industry.

"A reliability organization for interstate natural gas pipelines is the wrong approach to addressing the reliability problems identified during the discussion at today's FERC meeting," said INGAA CEO Amy Andryszak. "FERC exercises strict oversight of interstate natural gas pipelines and has promulgated regulations governing everything from construction to reporting of operational information to rates. As a result, interstate natural gas pipelines have a strong record of delivering on their firm commitments, even in extreme weather. There is no pervasive reliability problem across interstate natural gas pipelines like the electric reliability problems that led to the creation of NERC."

Commissioner James Danly said that a big part of the problem was the lack of infrastructure — and that FERC was largely to blame. While electricity is fundamental to the economy, it is not the only customer for natural gas, and customers need to pay for service, he said.

"There seems to be this assumption that it is entirely for the purpose of driving the electric reliability that the gas system should reorganize itself," Danly said. "And I think that even if that were the right way to go about things and the best public policy to implement, they get to have a say in how their own systems are used because we still have private property in this country, even in a regulatory regime."

The power industry has seen a major shift since the 1990s, when just 10% of generation was natural gas and that was for peaking, said Commissioner Mark Christie. Now 50% is natural gas and the bulk of that operates as baseload, he noted.

"Recommendation number seven says study whether we need more infrastructure," Christie said. "I think this frivolous. Of course, we do. Of course, we do. You can't turn your whole system from gas as a discrete peaker use and then make gas combined cycles your main baseload generation and not need more infrastructure."

Commissioner Allison Clements noted that some natural gas utilities were unable to heat customers' homes for up to eight days, but she questioned the need to build out more pipelines in response.

"We could come in and say we need more infrastructure, but the infrastructure that was there didn't work," Clements said. "From the production head through generation, we saw failures. We need to focus on the part we have jurisdiction over now, and industry needs to lean in, whichever part of the industry you're in, to cut through some of these problems."

Both Phillips and Robb said they have been arguing in favor of a new reliability regime for natural gas, and improved coordination between the two industries, for years.

"I think the issue we have in this country is that our recognition of the relationship between the natural gas system and the electric system hasn't caught up to the realities of how those two systems are intertwined," Robb said. ■

FERC/Federal News

Feds Release Road Map for Offshore Transmission Grid

Plan Highlights Need, Acknowledges Complexity, Difficulty

By John Cropley

Federal regulators on Sept 19 issued a *suggested road map* for building out the transmission network needed for the thousands of wind turbines envisioned off the Northeast coast.

The departments of Energy and Interior presented "An Action Plan for Offshore Wind Transmission Development in the U.S. Atlantic Region" as a tool to boost the offshore wind sector, strengthen the domestic supply chain and create jobs while protecting the climate.

It suggests immediate actions to connect the first generation of wind projects to the onshore grid and longer-term efforts to continue growing the new energy sector for decades to come.

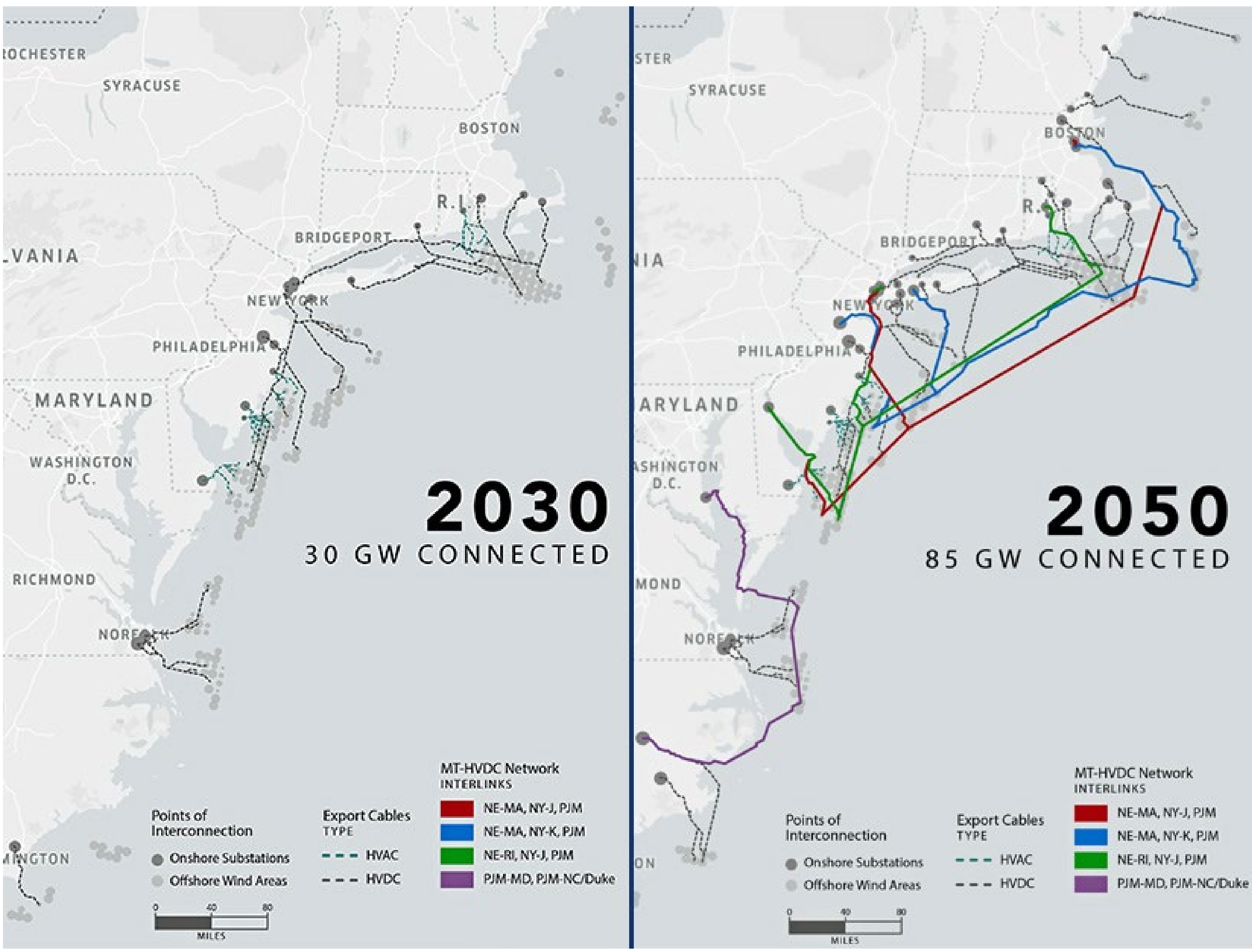
The Biden administration has set a goal of 30 GW of installed offshore wind generation by 2030. Subsequent federal goals and the individual goals of numerous states could push the total above 100 GW by 2050.

The Action Plan was shaped by a series of workshops with experts and stakeholders from early 2022 to early 2023 and by the forthcoming *Atlantic Offshore Wind Transmission Study* by DOE's Wind Energy Technologies Office.

The Action Plan identifies increased intra-regional coordination, shared transmission lines and a network of offshore HVDC interlinks as priorities. To accomplish this, it makes a series of recommendations for industry; local, state and federal governments; and other stakeholders.

These include:

- Before 2025: Establish collaborative bodies; identify steps to be taken, such as updating reliability standards and offshore-onshore interconnection points; create voluntary cost assignments and tax credits.



Maps in a new roadmap issued by the U.S. Department of Energy show suggested buildout of offshore wind transmission capacity. | *DOE*

FERC/Federal News

- From 2025 to 2030: Convene and coordinate with states to plan an offshore transmission network; with industry to standardize HVDC technology requirements; and with tribes, state agencies, stakeholders and federal agencies on priority transmission paths.
- From 2030 to 2040: Establish a national HVDC testing and certification center to ensure compatibility in the offshore grid network that is envisioned.

Offshore wind is one of President Biden's signature initiatives, but it faced significant challenges even before the financial and supply-chain hurdles that began to threaten progress in 2022.

Central among these challenges, the Action Plan states, is that there is no offshore grid.

A disparate collection of stakeholders with competing interests must create an expensive new piece of infrastructure that can carry large amounts of electricity long distances in a harsh environment using facilities that do not yet exist with equipment and components that are in short supply.

They must navigate multiple regulatory processes in each of as many as four levels of review — local, state, federal and tribal — while protecting the marine environment, respecting coastal communities and minimizing conflict with other ocean users.

They must connect to an onshore distribution grid that already is vastly oversubscribed and is not standardized between regions.

Networked transmission might help with this, but such interregional efforts carry their own set of planning, ownership and cost allocation challenges.

Coordinated transmission is "notoriously difficult" to develop.

All of this demonstrates the urgent need for proactive and coordinated transmission planning along the Northeast U.S. coast, the Action Plan asserts. It identifies several specific shorter- and longer-term obstacles:

- Near-term: Without a long-term planning vision, early projects using radial transmission lines could preclude future holistic transmission solutions; significant onshore upgrades will be needed to deliver the electricity coming off the ocean; siting is complex.
- Mid- and long-term: Offshore transmission costs are high, and cost allocation mechanisms are inadequate; developing new policies, standards and practices may delay projects; strategic planning must replace unsustainable current interconnection practices; separation of generation and transmission creates a risk that one becomes a stranded asset while the other is being completed.

Spiraling costs have become an issue with offshore wind, as inflation and interest rates drive up development expenses that ultimately will be borne by the American public, whether through utility rates or taxes or consumer costs.

The price tag of the envisioned interstate offshore grid is unknown, but the Action Plan cites a telling estimate in a report completed by the *Brattle Group* on behalf of several environmental advocacy and clean energy industry groups: Proactive transmission planning for a future 100 GW offshore wind industry would save at least $20 billion.

A leading offshore wind industry group applauded release of the action plan and highlighted the difficulty of the present-day development process.

"Rebuilding our transmission system is extremely complex, and the federal government can play a unique role bringing major parties together to break through barriers," said Liz Burdock, CEO of the Business Network for Offshore Wind.

"Along with ensuring that we can develop our industry, building out the grid in a coordinated fashion will yield enormous benefits for ratepayers and the environment, build confidence in the market's trajectory and accelerate development. We welcome the release of this action plan and encourage the federal government to begin working to bring states and stakeholders together." ■

Report Extols the Benefits HVDC Lines Offer the Grid

FERC Booster Touts Renewables' Low Cost

By James Downing

The U.S. is behind Europe in deploying HVDC transmission technology, according to a report released Sept. 19 by the Brattle Group and DNV for clean energy and transmission advocates.

"*The Operational and Market Benefits of HVDC to System Operations*" noted that 300 GW of HVDC capacity has been installed worldwide, with an additional 150 GW in the planning stages, most of it in the last decade. The report was sponsored by the American Council on Renewable Energy, Allete, Clean Grid Alliance, GridLab, Grid United and Pattern Energy Group.

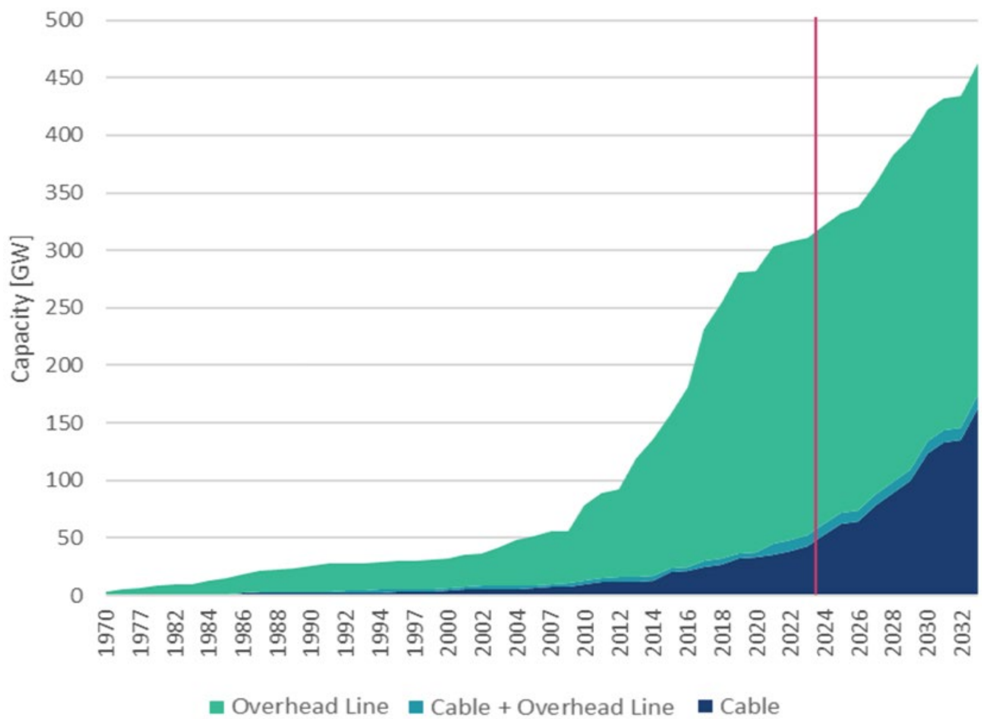
"HVDC transmission has evolved dramatically over the last five to 10 years," Brattle Group Principal and co-author Johannes Pfeifenberger said on a webinar hosted by ACORE. "HVDC offers higher capacity, longer distance [and] lower loss transmission on a smaller footprint, which really are key advantages."

Connecting HVDC lines to the standard AC grid requires converters, and the newer voltage-sourced converters, which can be switched on and off by an external control signal — unlike the historically more common line-communicated converters that can only be turned on by an external signal — greatly enhance HVDC's capabilities, Pfeifenberger said.

Europe has led the way in deploying modern HVDC technology with VSC converters recently, with about 50 GW of projects in operations and another 130 GW planned over the next 10 years. North America accounts for only 3% of the technology's use and 30% of planned projects, most of which have been proposed by merchant developers.

"It's pretty straightforward if you want to move power over long distance: DC is a much more efficient way to do that in terms of right-of-way cost and controllability," said Grid United CEO Michael Skelly, whose firm has proposed a number of HVDC *projects* to connect the three interconnections.

In the mid-2000s, when Texas was considering the Competitive Renewable Energy Zone lines to bring wind power to market, they considered HVDC; Skelly said now there might be a "little bit of buyer's remorse." With how much growth ERCOT has seen in recent years, HVDC might make a comeback, he added.



A graphic by the Brattle Group and DNV showing the rapid recent and projected growth in the use of HVDC technology around the world. | *DNV*

The one domestic market the report highlighted as fully embracing HVDC technology is CAISO, with Pfeifenberger noting that the Trans Bay Cable in the San Francisco area is the first VSC HVDC project in the world.

"Because they were the first operator of a VSC-based HVDC line, the Trans Bay Cable, they really like the technology; they have optimized it into the market; they're fully co-optimizing controllable transmission with generation in the day-ahead in real-time markets," Pfeifenberger said. "They're optimizing transmission across the entire West now. And they are developing a specific way to integrate merchant transmission lines into all this market optimization."

The report is full of anecdotes about European countries starting to knit their grids together with new HVDC lines. Germany is linking up its wind-rich north and solar-rich south with major projects. Italy, which has HVDC subsea cables connecting Sicily and other islands, is now expanding its use similarly to its northern neighbor. Other examples abound around the continent.

HVDC works better than AC lines when it comes to burying transmission, said DNV Vice President and report co-author Cornelis Plet.

"Whenever power needs to be transported over more than 50 miles by underground cable or maybe 300 to 400 miles per overhead line, HVDC is the only technical, feasible option," Plet said.

In addition to the ability to be out of sight, HVDC technology also requires a smaller footprint so it can help get transmission built in urban areas where new rights of way are very hard to procure, he added.

Another reason Europe has been building out so many lines is the growth of offshore wind, as DC lines can operate underwater. Now a major question on the continent is whether the HVDC lines should operate as single entities or be stitched together in an HVDC grid that overlays the AC system, Plet said.

One issue with the rapid growth in Europe is supply-chain concerns, as the manufacturing base — while currently sufficient — would be strained to try to meet an uptick in demand

FERC/Federal News

from North America as well, he added.

"The U.S. must build a similar project pipeline and, importantly, take advantage of the significant planning and operational experience that has already been gained with modern HVDC systems," Plet said.

Another hurdle to getting HVDC or other major transmission needed to expand renewable power and address climate change is the current permitting process, said Rep. Sean Casten (D-Ill.), Congress' chief FERC booster.

The lack of transmission is one of the two main problems with renewables, the other being that it "is too damn cheap," Casten said on the webinar.

"You've generated this problematic resource that is super cheap: Whether it's wind, whether it's solar, you have effectively zero marginal cost," Casten said. "And on the other end of that wire, you have a person or an entity — maybe it's an RTO, maybe it's a utility — who has an entire pile of assets that are dependent on earning $50, $60, $70/MWh, and you want to put $30 power into that market."

That gives the entities who would receive that cheaper power a clear economic disincentive to do so, he added. The politics of defending high prices are not good, so opponents come up with spurious arguments like transmission causes "eagle cancer," Casten quipped.

Casten and Rep. Mike Levin (D-Calif.) are working on a bill that seeks to be the Democrats' opening position on transmission permitting. The two are trying to make sure the industry's profit motive is aligned with transmission expansion to bring renewables to market, get the right participants in the planning process and then smooth out the siting and permitting processes.

"Let's not make it harder to permit a transmission line than it is to permit a natural gas pipeline, which it is as long as we have only one authority responsible for one of those," Casten said. ■

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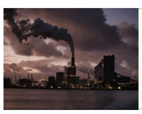

Federal Budgets, Procurements to Include Social Cost of GHGs — NetZero Insider

Treasury Issues Principles for Net-zero Financing, Investment — NetZero Insider

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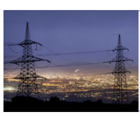

NERC Panel Disbands EMP Working Group, OKs Guidance on Grid-forming Storage — ERO Insider

NERC Standards Committee Briefs: Sept. 20, 2023 — ERO Insider

FERC/Federal News

FERC Directs J.P. Morgan to Declare Affiliations of Two Holding Firms

Commissioner Argues that Concurrence, Dissent Should be Equal; Chairman Disputes Notion

By James Downing

FERC issued an order Thursday finding J.P. Morgan Investment Management qualified as an affiliate of Mankato Companies and IIF US Holding 2, through which it is tied to other firms, including El Paso Electric.

The order came after a Section 206 briefing process FERC started after consumer group Public Citizen questioned the investment bank's ties to firms it said were not appropriately disclosed.

Public Citizen said the investment bank effectively controlled IIF, through Mankato and other subsidiaries. The two legal entities share employees and effectively let the investment bank make decisions on running IIF.

FERC found the relationship between J.P. Morgan Investment, IIF and Mankato was such that there is liable "to be an absence of arm's length bargaining in transactions between them," so it's appropriate to consider them affiliates for the protection of investors and consumers.

The two firms share operations under an Investment Advisory Agreement and a Partnership Agreement, which delegate J.P. Morgan Investment broad duties to run IIF. A J.P. Morgan Investment employee sits on the board of directors of Onward Energy as a representative of IIF.

"We emphasize that in the market-based rate context, an assessment of affiliation is necessary to understand the relationships between entities to ensure that rates are just and reasonable, to protect against the exercise of market power and to protect customers from affiliate abuse that can result from affiliate transactions, regardless of the presence of fiduciary duties," FERC said.

Employees of J.P. Morgan and J.P. Morgan Investment signed the partnership agreement and investor advisory agreement for both firms. That at least shows J.P. Morgan was empowered to execute documents that bind IIF into agreements, including agreements with the investment bank itself.

The investment agreement between the firms authorizes J.P. Morgan as investment adviser to "have full authority to undertake and perform any and all acts deemed necessary or appropriate by it in connection with the rights, powers and duties delegated to it." The partnership agreement explains J.P. Morgan has the power to manage IIF's business and affairs, to make business decisions, to act on its behalf and take any actions it deems appropriate.

The skyscraper at 270 Park Avenue is home to the J.P. Morgan headquarters. | *CrossingLights, CC-BY 4.0, via Wikimedia*

"These rights and powers allow J.P. Morgan Investment to make virtually every major decision on behalf of IIF US Holding 2," FERC said.

The commission directed Mankato to file a change in status and update its asset appendices to reflect J.P. Morgan Investment as an affiliate. The firm's market power analysis will need to be updated to reflect the affiliation.

The order drew a concurrence from Commissioner James Danly, and a response to that from Chairman Willie Phillips.

Danly wrote to make clear that while he supports the outcome of the order, he takes issue with the majority's reasoning. He argued concurrences should be the same as a dissent as a result.

"I disagree with the means by which we arrive at that conclusion," Danly said. "I do not believe that we need to disclose privileged information to the extent we do to justify our conclusion. We could and should have been more measured."

Phillips said concurrences amount to the opposite of a dissent and Danly cited no precedent supporting his view that concurrences should be treated that way on review by the courts.

"Commissioner Danly is, as ever, entitled to his opinion," Phillips said. "I write separately to stress that I do not share that opinion and to underscore that Commissioner Danly is not stating the commission's view on this issue. As Commissioner Danly correctly notes in his concurrence, it is our agency's 'institutional decisions — none other — that bear legal significance.'" ■

FERC/Federal News

FERC Rebuffs PJM, SPP on FTR Credit Rules

Proceedings for CAISO, ISO-NE, NYISO Terminated

By Devin Leith-Yessian, Tom Kleckner, Jon Lamson, John Norris and Rich Heidorn Jr.

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FERC said last week it remains dissatisfied with PJM's and SPP's financial transmission rights (FTR) credit policies, while ending inquiries into those of CAISO, ISO-NE and NYISO.

The commission ordered PJM to institute a 99% confidence interval in its policy and said SPP's tariff "appears" to be unjust and unreasonable in the absence of a mark-to-auction collateral requirement or comparable alternative.

Following a 2021 technical conference on RTO/ISO credit practices, FERC in July 2022 opened investigations under Section 206 of the Federal Power Act into SPP, CAISO, ISO-NE and NYISO. (See "Collateral Requirements" in *FERC Proposes Allowing RTOs to Share Credit-related Info*.)

The commission said it was concerned the grid operators' tariffs did not ensure that FTR traders maintain sufficient collateral to reduce mutualized default risk, where a default by a market participant unsupported by collateral must be socialized among all participants.

The commission's concerns were sparked by the 2018 bankruptcy of GreenHat, which cost the PJM membership nearly $180 million — only $1.4 million of which could be recovered from the company's principals once GreenHat was insolvent. (See *FERC OKs GreenHat Settlements*.)

Excluding PJM and SPP, the commission last week found the other grid operators' tariffs remain just and reasonable and terminated their proceedings. (See below.)

PJM Ordered to Institute 99% Confidence Interval

In its Sept. 21 order on PJM, FERC accepted all aspects of the RTO's June 2022 filing revising its FTR rules, except for the RTO's proposal to use a 97% confidence level in its historical simulation (HSIM) model. It ordered use of a 99% level instead (*EL22-32*).

The commission said a 97% confidence interval would capture only events occurring more than once every 2.75 years, failing to account for rare, but high-risk events such as large, unexpected transmission outages or the February 2021 winter storm that caused generation outages across Texas.

"The record before us fails to show that considering such a short period of time will produce adequate collateral requirements, as it would exclude major, albeit potentially infrequent, events that cause significant price moves affecting the value of FTRs. For example, such a short period of time could exclude extreme but foreseeable events like Winter Storm Uri or the 2014 Polar Vortex, which occurred more than three years apart," the order states.

The commission said the 99% value would include events that occur at least once every 8.25 years. It directed PJM to submit a compliance filing within 30 days reflecting the change.

"As a general matter, FTR market participants should be, and are, in the best position to bear the principal cost of insuring against their risk of defaulting on the FTR portfolio positions that they acquire voluntarily. An HSIM model with a 99% confidence interval puts that principle into practice by striking an appropriate balance in requiring adequate collateral to protect market participants against the consequences of default without begetting the adverse impacts, e.g., reduced market liquidity, of over-collateralization. And contrary to PJM's earlier claims, there appears to be little danger of significant 'collateral shock' or 'market disruption'" by requiring FTR market participants to cover more of their own risk instead of transferring a portion of it to other PJM members," the order states.

FERC agreed with the Independent Market Monitor's contention that PJM's cost-benefit analysis was flawed and did not capture the full benefits of a 99% vs. 97% confidence interval. PJM held throughout the proceeding that the costs of a 99% interval would exceed the benefits; several load serving entities, including Duke Energy and Old Dominion Electric Cooperative filed comments agreeing with PJM's stance.

The commission accepted the remainder of PJM's filing as is, including replacing the long-term FTR credit recalculation with real-time price updates, revising the $0.10/MWh volumetric minimum charge to apply after adjusting for auction revenue rights credits or mark-to-auction value and revising its tariff to explicitly state that a decline in FTR portfolio value leads to an increase in the FTR credit requirement, as well as the inverse. The order also removes the undiversified adder, which applies to market participants deemed to present heightened risk from being undiversified. Following the GreenHat default, PJM said, the adder was determined to not correlate with fluctuating market risk.

SPP Ordered to Show Cause on Lack of Mark-to-auction Mechanism

In a separate order, the commission expanded the scope of its show cause proceeding for

FERC/Federal News

SPP and directed further briefing (*EL22-65*).

The commission gave SPP 60 days to show cause as to why its tariff remains just and reasonable and to respond to eight questions. It directed the RTO to explain the tariff changes it believes would remedy FERC's concerns.

The commission faulted SPP's transmission-congestion rights (TCR) market for lacking a mark-to-auction collateral requirement or a comparable alternative. The mechanism can mitigate excessive risk-taking by allowing the grid operator to make a collateral call if auction prices reveal that FTRs acquired in a prior auction are declining in value.

The commission said SPP's credit policy failed to "address the credit default risk the commission identified in the show cause order."

The commissioners said the RTO's existing reference price methodology relies solely on historical congestion patterns and does not incorporate updated TCR portfolio valuations. FERC also said SPP's improved credit requirements for TCR market participants did not directly address the increased default risk.

The commission said it remained "concerned" that a mark-to-auction mechanism or comparable alternative was not included in SPP's tariff and noted the grid operator said its TCR auction process is not within the show cause order's scope. FERC said SPP's response raised issues that "require augmentation of the existing record" and it included a list of questions.

SPP staff said they are reviewing the order and plan to respond by Nov. 20.

CAISO

In terminating the proceeding regarding CAISO, the commission found that the ISO's mark-to-auction valuation addresses the risk that an FTR portfolio — congestion revenue rights (CRR) in CAISO's nomenclature — may decline in value over time (*EL22-62*). "We also find that CAISO's existing volumetric alternative minimum collateral approach ensures that market participants maintain some minimal level of collateral that scales with the size of their CRR portfolio and cannot minimize their required collateral without correspondingly reducing their risk," the commission said.

"The risk of a CRR portfolio changing over time is captured by incorporating the most recent CRR auction results as part of the financial security requirement calculation," the order continued. "As noted in CAISO's response, this approach incorporates a mark-to-auction mechanism and captures risks that emerge when auction results diverge materially from historical outcomes."

The commission said several other factors reduce overall risk in the CAISO CRR market: CRRs are offered with a maximum open position of only three months and may be purchased only for paths associated with physical supply delivery.

The commission noted that CAISO uses a different approach from PJM, MISO or SPP, all of which require a flat $/MWh amount on FTR portfolios. "CAISO nonetheless requires a volumetric value to be posted as collateral that is weighted to produce a $/MWh amount, which imposes a higher requirement on negative or low positively valued CRR portfolios," it said.

ISO-NE

FERC said ISO-NE's collateral requirements are just and reasonable, agreeing with the grid operator that the tariff's existing provisions require market participants to maintain collateral scaled to the size and risk of their FTR portfolio (*EL22-63*).

It agreed with the RTO that "the lack of a volumetric minimum collateral requirement does not render ISO-NE's existing collateral requirements unjust and unreasonable."

The commission took issue in the show cause order with ISO-NE's lack of a volumetric minimum collateral requirement. The RTO responded that it is already well protected from risk due to its FTR financial assurance requirements and the fact that it doesn't offer long-term FTRs.

NYISO

The commission said NYISO convinced it that it has adequate protections against defaults in its FTR market — called transmission congestion contracts (TCC) — despite the absence of a volumetric alternative minimum collateral requirement (*EL22-64*).

The commission cited the ISO's alternative approach to ensure market participants "maintain some minimal level of collateral that scales with the size of their FTR portfolio and cannot minimize their required collateral without correspondingly reducing their risk."

Unlike PJM and MISO, NYISO requires full payment for TCCs purchased in auctions upon completion of the auction, except for the second year of a two-year TCC. "We find that this key difference in settlement design ensures that market participants at a minimum must post the full auction price of an awarded TCC and, thus, prevents a market participant from minimizing its collateral without reducing its risk," the commission said.

The commission cited a NYISO analysis that found the grid operator's existing collateral requirements — $0.15/MWh for balance-of-period TCCs, $0.40/MWh for future six-month TCC, and $0.053/MWh the second year of a two-year TCC — were always greater than the minimum requirements in other markets ($0.10/MWh for PJM and SPP, and $0.05/MWh for MISO). ■

CAISO/West News

Stakeholders: Pathway Initiative Offers 'Fresh Look' at Western Market

Region's Participants also Caution that Transparency is Key to Success in the Effort

By Robert Mullin

Proponents of a West-wide electricity market cite the environmental and economic benefits of sharing renewable resources across as large a footprint as possible. | *© RTO Insider LLC*

Stakeholders from across the Western electricity sector say they see renewed potential for developing a more organized regional market through the open-ended process offered by the West-Wide Governance Pathway Initiative.

But many of them also caution that the initiative must become more transparent, both in its processes and its sources of funding.

Those were two of the key takeaways from stakeholder comments filed in response to questions in an Aug. 29 letter circulated by the backers of the initiative, who are seeking to quickly work through "Phase 1" of the effort to define a governance framework and seat a founding board of directors by next January. (See *Backers of Independent Western RTO Seek to Move Quickly*.)

Utilities regulators from Arizona, California, Oregon, Washington and New Mexico established the initiative in July to improve the prospects for developing a single, West-wide electricity market that pointedly includes California — a response to the competition for members between CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+.

The *comments* were posted on the website of the Western Interstate Energy Board. The solicitation received 36 individual comments and five sets of joint comments — a few of which also included contributions from some of the individual commenters.

'Fresh Look'

The Aug. 29 letter asked stakeholders to address questions related to the initiative, including the pros and cons of it being facilitated outside of any existing organization and the preferred structure, process and scope for Phase 1. It also asked for opinions on the best stakeholder engagement model for enabling broad stakeholder involvement and ensuring efficiency.

Multiple parties pointed to potential benefits of conducting Phase 1 of the Pathway Initiative outside the auspices of any existing organization or process.

A group calling itself "Joint Commenters" — which includes RTO advocacy group Western Freedom; American Clean Power Association; multiple utilities in California, Oregon and Washington; and other industry groups — said the approach offered the advantage of separating "the discussion from existing market institutions and can enable a fresh look at certain structural and governance issues that have been examined in other contexts."

The Bonneville Power Administration, which some Northwest stakeholders say is leaning toward joining Markets+, said the initiative "offers the opportunity for a different approach to create a multi state entity for market development than other entities have taken."

"It has the opportunity to be a new, intentionally designed entity, separate from existing organizations. As a new entity, it could develop appropriate practices about how a multi state entity can operate and engage," BPA wrote.

But one downside, BPA said, is that "[t]he new entity and its structure will need to be created rather than being able to rely on an existing structure," which could hinder "the ability to move quickly."

BPA has previously said it will issue a decision on which day-ahead market to join in March 2024, a timeline that some Northwest stakeholders consider to be too aggressive given the importance of the agency's transmission and generation for the wider West and all the variables currently in play. (See *NW Stakeholders Divided on BPA Timeline for Day-ahead Decision*.)

In its individual comments, Portland General Electric, one of the Joint Commenters, said the open-ended nature of Phase 1 could bring "renewed enthusiasm" to the effort to develop a Western market. But the Oregon utility also said "it is crucial to demonstrate continued support of key California political leaders, especially the California Energy Commission and California Public Utilities Commission."

"Past efforts at regionalization have faced skepticism and resistance within California, and strong engagement from both California and Western leaders is needed to ensure that this effort produces an outcome that is acceptable to both California stakeholders and the wider West," PGE said.

BPA suggested the first phase of the initiative focus "on demonstrating the viability of establishing an independent entity capable of administering contracted market services

CAISO/West News

from an existing market platform."

"While establishing effective independent governance of the initiative is of critical important [sic] to Bonneville, the requirements for an independent governance structure have been well-discussed through the existing market initiatives (WRAP, EDAM and Markets+). The initiative can draw from those experiences rather than spending the bulk of Phase 1 focused on what is needed for independent governance," BPA wrote.

BPA also said it "respectfully" disagreed with an assertion by backers of the initiative that there was "broad stakeholder agreement" that the WEIM's joint authority governance model would be sufficient for governing the EDAM.

"While Bonneville participated on the Governance Review Committee and supported its final recommendations within these constraints, we cautioned that 'Broad adoption of EDAM across the interconnection is likely to be challenging if the market design is not founded upon an independent governance structure.'"

Transparency Required

A recurring theme in comments was the need for transparency around the initiative.

"It is important that whoever is leading this work create a process that is truly open, transparent, impartial, and inclusive," *said* the British Columbia Ministry of Energy, Mines and Low-Carbon Innovation.

The ministry "strongly" encouraged the organizers "to identify which state/provinces [sic] are leading the initiative, the source of any funding received to date, and how decisions will be made with respect to a proposed governance structure."

Arizona Public Service (APS) noted that "assistance from outside experts" will be needed to advance the effort in a timely way and "influence potential market participants' decision making.

"Transparency is requested to monitor the source of funding for and perspective of initiative facilitators. At this juncture it is also unclear whether the regulator sponsors or broader WIEB membership is at the helm of the initiative," APS said, expressing a concern also shared by *NV Energy*. The Nevada-based utility urged initiative backers to be transparent about the source of funding throughout the process.

Lack of transparency about funding appeared to be one of the key concerns for the Idaho Public Utilities Commission, which earlier this month voted unanimously to decline to sign on to the initiative. (See *Idaho PUC Declines to Join Western RTO Governance Effort*.) The PUC reiterated that concern in its terse *filing*.

The Utah Office of Consumer Services *said* the Aug. 29 letter's "simple statement" that the funding is "derived from 501(c)(3) sources" was "wholly inadequate."

"Unfortunately, experience has shown that having this tax status does not ensure that the organization has a mission consistent with the public interest and/or includes organizations with highly specific objectives that at best represent a subset of the public interest. Those promoting this initiative must disclose the specific funders so that potential participants can better understand potential goals associated with the funding," the Utah agency said.

The Utah consumer advocate sought clarity on the rationale for seating the entity's board during Phase 1.

"The timing does not appear to allow for a fulsome recruitment, vetting, and selection process. If only 'key elements' of governance are in place by December, that barely allows for enough time to have sectors coalesce and select nominating committee members by January," the agency said.

Competitive Advantages

The initiative won strong praise in *comments* from a group that includes Western Freedom, Silicon Valley Leadership Group, Environmental Defense Fund, CalChamber, American Clean Power Association, California Environmental Voters and the Union of Concerned Scientists.

The proposal "identifies maximizing benefits for customers as the goal for the new entity and future market services it will provide," the group said. "This sends a clear message that market decisions should be driven by and be able to demonstrate those benefits. It also signals a clear understanding of the sense of urgency for regionalization efforts to maximize benefits through expanded market services."

The group said large industrial and commercial electricity customers "face very real barriers to expansion in the West" because the region lacks an organized market to "provide affordable, reliable, and cleaner energy. A centralized market offers the ability to lower costs by unlocking the full potential of existing generation and decreasing costs."

The group also pointed out that 80% of Western residents live in areas with clean energy targets that can't be met without the benefit of a "fully integrated market" across the region.

The group was among those commenters, including BPA, who cautioned about the large investment of time and resources required to pursue the effort, advising that "there is some essential research and analysis that needs to be conducted at the earliest stages of this process to ensure there is a viable path forward." It called for the initiative's backers to identify a lead organization that can hire consultants, including "a facilitator, legal counsel and technical research."

"The Western Interstate Energy Board through the Committee on Regional Electric Power Cooperation could be ideal, given its membership of states and its Department of Energy funding," the group said.

A group calling itself "Joint Competitive Stakeholders" also *pointed* to a different set of competitive benefits from a West-wide market — for competitive power suppliers, transmission and generation developers, and financial institutions. The group includes independent power producer associations in California and the Northwest; energy traders such as DC Energy and Shell; and developers like New Leaf Energy and Vistra.

"Phase 1 of the Initiative, and any future phases, must provide fair representation for all types of market participants and interested parties. This representation will ensure that any new regional Western market establishes policies and operates in a fair and non-discriminatory manner to foster competition and unlock the greatest benefits," the group wrote.

The Competitive Stakeholders said the initiative's first deliverable should be to develop "a conceptual framework" on governance in a process that includes members of its sector, followed by drafting of governing documents.

"It will be key to establish a sound governance framework and good governance principles in Phase 1 to be used in implementation by the founding board in Phase 2," the group said.

NV Energy said it seeks to "have up front agreement on the objective — to develop a governance structure that is independent in both reality and perception." Both APS and NV Energy urged that a new entity not differentiate by the size of participating states. The latter also raised the need for equal treatment of different public policies.

CAISO/West News

"If a Western organized market is to have broad participation it must accommodate states that have adopted GHG programs, states that have pursued decarbonization by means of renewable portfolio standards, and states that have not established carbon-related regulations," NV Energy wrote.

The Nevada utility also asked the initiative to address some practical matters, such as: which CAISO activities could be transferred to the new entity; whether the entity would be responsible for reliability coordinator activities as well as market functions; the potential for the new entity to assume the role of a balancing authority; and the entity's role related to transmission planning and cost allocation.

'Broader' Representation

Oregon-based PNGC Power, an electric cooperative with 16 members in seven Western states, *expressed* support for the Aug. 29 letter and encouraged expansion of the regulators' coalition "to include broader industry sector representation."

"This includes entities with an interest in exploring pathways to an RTO, including strong representation from the Northwest region, including BPA's public power customers that explicitly and clearly support forming an RTO as an end state," PNGC wrote.

The co-op also urged the coalition "to ask for financial and resource commitments from all participating members of the Founding Board to ensure that they are fully committed to the effort and that they are not just attending to express opposition and slow down the process." The commitments should be significant enough to "weed out" those who might seek to impede development of an RTO but "reasonable enough" to allow participation by organizations of "varying sizes," it said.

While backers of the Pathways Initiative appear to assume a new entity would contract with CAISO to provide market operator services, some commenters suggested the selection process should be opened to competition.

BPA said the new entity should consider "all options" for a potential market operator and possibly rely on an "RFO-type solicitation" (request for offer) for making its choice. APS said the initiative's Phase 1 activities should be expanded to include exploring a governance structure that could be applied to any potential market operator.

"Currently, both CAISO and SPP are maneuvering to offer expanded market services to the region. Additional program facilitators may emerge," APS wrote.

Regarding the question of stakeholder engagement, a large number of commenters suggested the Pathway Initiative borrow from the lessons learned from other Western governance structures, such as those for the WEIM, Western Power Pool and the fledgling Markets+ effort. ■

Calif. Governor: 'Climate Crisis Is a Fossil Fuel Crisis'

UN Summit Calls for Accelerated Action on Emission Cuts, Climate Finance

By K Kaufmann

For the world to have any hope of limiting climate change to 1.5 degrees Celsius, well-off countries around the globe must stop burning coal by 2030 and cut emissions economy-wide to net zero no later than 2040, according to the United Nations' *Accelerated Climate Action Agenda*.

UN Secretary General António Guterres | *United Nations*

Those aggressive goals were the centerpiece of the opening plenary of the *UN Climate Ambition Summit* in New York City on Wednesday, with Secretary General António Guterres calling out governments and business for "foot dragging, arm twisting and the naked greed of entrenched interests" that have slowed efforts to curb greenhouse gas emissions.

"Humanity has opened the gates of hell," Guterres said, reeling off a growing list of climate disasters: floods, wildfires and extreme heat. "Climate action is dwarfed by the scale of the challenge. If nothing changes, we are heading towards a 2.8-degree temperature rise, towards a dangerous and unstable world."

The UN Climate Ambition Summit in New York City on Wednesday set the stage for the upcoming COP 28 conference in the United Arab Emirates. | *United Nations*

Setting the stage for the *UN Climate Conference* (COP 28) in the United Arab Emirates in December, Guterres also called for an end to subsidies for fossil fuels worldwide, which the International Monetary Fund (IMF) pegged at $7 trillion in 2022.

Instead, the accelerated agenda shifts fossil fuel subsidies to renewable energy and ends all licensing and public and private funding for new oil, coal and gas. Targets for developing nations are 2040 for coal phaseout and 2050 for economywide net zero.

"Governments must push the global financial system towards supporting climate action, and that means putting a price on carbon and overhauling the business models of multilateral development banks so that they leverage far more private finance at a reasonable cost to developing countries," Guterres said.

Businesses and financial institutions also must embark on true net-zero pathways, he said. "Shady pledges have betrayed the public trust … using wealth and influence to delay, distract and deceive, and this is shameful."

Part of the UN General Assembly, the Climate Ambition Summit plenary laid out the issues and potential flashpoints that will resurface at COP 28 as the nations that signed the Paris climate accords in 2015 face the first official global stocktaking of the world's progress on climate, required by the agreement.

The UN's initial *global stocktaking report*, released Sept. 8, said global action on cutting GHG emissions is lagging, and limiting climate change to 1.5 degrees would mean a 43% drop in emissions by 2030 and a 60% drop by 2035. (See *UN Report Calls for Quicker Global Emissions Reductions*.)

But concerns about progress at COP 28 already are high in some quarters as the U.A.E. has named Sultan Ahmed Al Jaber, CEO of the Abu Dhabi National Oil Co., as the conference president. Speaking at a climate conference in Brussels in July, Al Jaber *called for* an accelerated "phasedown" of fossil fuels, as opposed to a phaseout, supported by a tripling in the deployment of renewables and a doubling of energy efficiency.

"Phasedown" also was the language used by G20 energy transition ministers in the *final document* coming out of their meeting in India in July, in which disagreements were noted about the extent and nature of any future phasedown.

Pairing emission cuts with increased renewables and energy efficiency is gaining support. Ursula von der Leyen, president of the European Commission, said the European Union is working with Al Jaber, Kenya, Barbados and other countries to build a global consensus on the renewable energy and energy efficiency targets ahead of COP 28.

Fossil Fuel Nonproliferation

Guterres billed the summit as an event to recognize the efforts of the nations and organizations moving ahead on ambitious climate action, while also signaling frustration with major polluters, including the United States

CAISO/West News


California Gov. Gavin Newsom | *United Nations*

and China, which were not invited to speak.

However, California Gov. Gavin Newsom (D) earned strong applause for his indictment of major oil companies, following the state's suit filed Friday against Exxon, Shell, Chevron, ConocoPhillips, BP and the American Petroleum Institute, an industry trade group. (See *Calif. Sues Oil Majors over Climate Impacts*.)

"It's time for us to be a lot more clear this climate crisis is a fossil fuel crisis," Newsom said. "It's not complicated. It's the burning of oil; it's the burning of gas; it's the burning of coal, and we need to call that out. For decades and decades, the oil industry has been playing each and every one of us in this room for fools. They've been buying off politicians. They've been denying and delaying science and fundamental information that they were privy to that they did not share."

Echoing Newsom, Chilean President Gabriel Boric said, "We have to leave fossil fuel behind, and that, in very specific terms, means that we also have to react to the greenwashing that major businesses are undertaking. They continue with that greenwashing, and they're stepping it up. In some cases, their greenwashing efforts are supported by countries.

"If we're not able to make these groups yield to our will and to make them yield to the will of the international community as expressed by the leaders here present and by the activists here … the truth is that we won't hit our targets."

Prime Minister Kausea Natano of the Pacific island nation of Tuvalu, believes the way forward must include "a comprehensive, multilateral framework that addresses the climate crisis at each root cause. A negotiated fossil fuel nonproliferation treaty would complement the Paris agreement and ensure a global [energy] transition."

Von der Leyen also promoted wider adoption of carbon pricing as a way to raise money to support clean energy transitions in developing nations. In addition to cutting emissions 55% by 2030, the EU also will work with the UN "to have at least 60% of global emissions covered by carbon pricing by 2030," she said.

"Today, it's only 23% [of emissions] that are covered, and this brings in revenue already of $95 billion. Just imagine [if] we could cover 60% of global greenhouse gas emissions, the amount of revenues that we would get to invest in low- and middle-income countries."

Restructuring Global Finance


Canadian Prime Minister Justin Trudeau | *United Nations*

Canadian Prime Minister Justin Trudeau credited his country's carbon pricing with GHG emissions that have been trending down since 2019, even as Canada continues to be a major fossil fuel exporter.

The country has a plan for cutting emissions 40% by 2030, that "goes sector by sector, laying out exactly how we will cut our emissions," he said. "By the end of the year, we will be announcing our framework to cap emissions from the oil and gas sector."

Regulations on cutting methane emissions from the oil and gas sector 75% below 2012 levels also are being prepared and "will be designed to help us exceed this already ambitious target," he said.

Gustavo Petro, president of Colombia, another major fossil fuel exporter, argued for a more radical approach to the phaseout of oil and gas, recognizing first the enormous economic and political power of the industry.

Even the goal of net zero is not viable, Petro said, because "the natural absorption capacity of the planet and the oceans, the forests, the jungles is decreasing, so net zero doesn't really exist."

Phasing out fossil fuels will require changing the economic structures of countries, like Colombia, that are dependent on the industry, Petro said. "Capital needs to be essentially separated from economic interests where fossil fuels are concerned.

"You need to compensate oil- and gas-producing countries for plugging their deposits, [for] no longer plundering them," he said. "Rather you need to give them money for mitigation and adaptation. That finance won't come from a private capital market. These major financial resources can only be produced if we restructure the global financial system."


Prime Minster Mia Mottley of Barbados | *United Nations*

A strong advocate for the restructuring of global finance, Mia Mottley, prime minister of Barbados, said, "The reality is that developed countries are going to have to find new mechanisms and new forms of carbon taxes while looking [to] ensure that there is not consequential impact that is incapable of being borne on cost of living. …

"Equally, developing countries will need a new mechanism to reduce the costs of hedging the billions of inward investment required," she said. "We believe that the [tripling] of the multilateral development bank lending is critical."

Mottley also hammered on the importance of a well-capitalized loss and damage fund, to compensate developing countries with low GHG emissions for the damage they've sustained from climate change. The establishment of a loss and damage fund was a major outcome of COP 27 in Egypt last year, but getting countries or companies to contribute to the fund will be one of the key challenges at COP 28.

"It is painful to continue to see that you are asking us to increase borrowing to build resilient infrastructure for something that we did not do," Mottley said. "And then at the same time, you want to ensure that you have a loss and damage fund that does not have the adequate means for grant funding to be able to help countries to rebuild. It is unconscionable." ■

CAISO/West News

‘Challenging’ Grid Conditions Led to CAISO’s Summer Emergency Alerts

By Elaine Goodman

CAISO’s issuance of energy emergency watches and alerts on three days in July came under conditions that mirrored those during California’s September 2022 heatwave, officials said.

Several “challenging evenings of grid operations” led the ISO to issue a Stage 1 energy emergency alert (EEA 1) on July 20, followed by EEA watches on July 25 and 26, CAISO CEO Elliot Mainzer told the Board of Governors on Thursday.

The period was marked by high demand from a record-setting heat wave in the Southwest, Mainzer said, while demand was “high but not excessive” in California and hydro conditions in the Pacific Northwest were below average.

In the Southwest, record-breaking temperatures included an average high in Phoenix of 114.7 degrees for the month of July, compared to the previous record of 109.8 degrees in July 2020.

“In many ways, conditions were the mirror image of what we saw last September when California was on the edge with a historic heat wave, and other regions were able to supply us with large quantities of power to help maintain reliability,” Mainzer said in a *report* to the board.

So far, the three alerts are the only times CAISO triggered the emergency alert system this year, Mainzer said. No Flex Alerts — in which consumers are asked to voluntarily conserve energy — have been issued in 2023.

In addition to Mainzer’s report to the board, CAISO also released last week a summer market *performance report* for July that goes into more detail on the EEA events. A Sept. 27 *meeting* has been scheduled to discuss the report.

July 20: EEA 1

Energy emergency alerts range from EEA 1, which includes calls for conservation measures and demand response, to EEA 3, in which rotating blackouts may be ordered. An EEA watch is a preliminary step before CAISO declares an alert.

When an energy emergency alert or watch is issued, CAISO has access to additional resources, such as the emergency load reduction program (ELRP), in which electricity customers are paid to voluntarily reduce their demand, and the state’s Strategic Reliability Reserve.

CAISO issued an EEA 1 at 7:30 p.m. on July 20 in response to “rapidly evolving grid conditions observed during real-time operations,” according to the monthly performance report. The July 20 conditions came up relatively unexpectedly, in contrast to grid events in 2020 and 2022 that were projected far in advance, the report said.

One and two days ahead, the market seemed able to meet the projected demand for July 20, although with thinning capacity margins.

But as the system approached net load peak on July 20, “the anticipated supply did not fully materialize,” the report said.

CAISO said reasons for the decreased supply included resource outages and derates; fewer imports due to potential fire impacts; and resources not dispatched due to congestion.

At the same time, demand was high from the desert Southwest, which experienced record-breaking high temperatures this summer. As a result, net imports were reduced during the net load peak.

Another issue was that a display of resource availability overestimated the amount of resource dispatch capability available — mostly due to storage resources that were providing multiple services, CAISO said.

As a result of the EEA 1, CAISO deployed resources from the ELRP. Normal operations resumed around 8:30 p.m.

July 25 and 26: EEA Watch

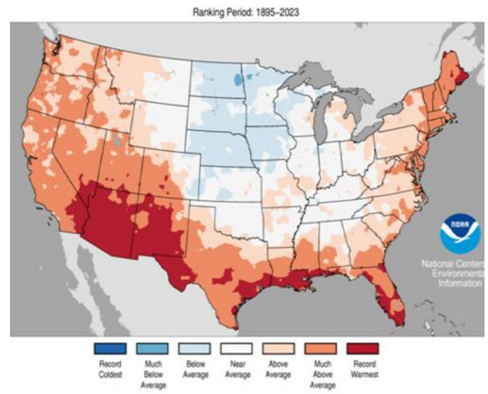
Factors similar to those that occurred on July 20 led CAISO to issue an EEA watch on July 25, effective at 7:30 p.m.

The ISO said it was seeing high external demand, wildfire threats to transmission, and the loss of about 2,000 MW of California resources “due to outages between the day-ahead and real-time markets.”

During peak hours, congestion on the Path 26 transmission lines made it difficult to send supply from the northern part of the system to Southern California, where it was still hot.

Another EEA watch was issued for July 26, from 6 to 10 p.m.

The report also discussed the flexible ramping product used by the real-time market. The EEA 1 on July 20 was sparked by a ramping shortfall as solar resources went offline in the evening hours.



Mean temperature percentiles for July 2023 | *NOAA*

The ramping product doesn’t procure capacity in response to unexpected outages or loss of imports, and so it had limited success addressing emerging uncertainty issues during the July events, CAISO said.

September 2022 Heat Wave

This year’s highest peak demand so far was 43,545 MW on July 25 at 6:27 p.m., well below the record peak of 52,061 MW on Sept. 6, 2022, during last year’s California heat wave. CAISO declared an EEA 3 that day but rotating blackouts were avoided after the governor’s Office of Emergency Services sent out a text alert at 5:45 p.m. urging consumers to conserve electricity.

Within 20 minutes, demand plunged by 2,385 MW and blackouts were averted. (See *CAISO Reports on Summer Heat Wave Performance*.)

Overall, operational conditions this summer have been “significantly less strained” compared to last year, CAISO said.

The state has been better positioned in terms of resource adequacy because of a record snowpack and strong hydro production, along with the addition of significant amounts of generating and storage resources.

Mainzer said August was another month with “a set of interesting conditions West-wide.” CAISO expects to release a market performance report for August next month. ■

Weatherization Practices Paying Off in Texas

PUC's Gleeson Cites Improved Performance; RRC Executive Cites 30,000 Inspections

By Tom Kleckner

The Texas Public Utility Commission's executive director last week praised the efforts of the state's regulatory agencies to push utilities to weatherize their facilities following the disastrous 2021 winter storm.

Speaking during the Texas Reliability Entity's annual winter weatherization workshop, the PUC's Thomas Gleeson said both the PUC and the Texas Railroad Commission (RRC), which regulates the intrastate natural gas and oil industry, have approved orders that have strengthened the electric grid and gas infrastructure against extreme weather.

"If you look at the acute onset issues that happened during Winter Storm Uri and also what you saw some of during Winter Storm Elliott, those mitigation tactics have worked," Gleeson said during the Sept. 13 workshop. "We've performed better, and I think we can all agree that as we continue to learn more, we'll continue to iterate all those rules to ensure that the grid remains reliable and resilient and progresses even further."

The two commissions have added winter and summer weather preparedness standards for the utilities they regulate and have followed up with inspections to ensure compliance. ERCOT has inspected more than 1,100 generation resources and transmission facilities before the past two winters. Gleeson said only four inspected sites were forced offline or derated during Elliott.

New weatherization rules are intended to prevent freezing issues like those during the 2021 winter storm. | *Entergy*

Inspections for summer preparedness began in June. Gleeson said about 500 inspections of generation and transmission sites will be conducted and a final report issued in October.

Mysti Doshier, the RRC's assistant director of critical infrastructure, said a "majority" of operators have achieved compliance at more than 99% of the 7,250 inspections the commission has inspected. More than 99% of violations were resolved within 30 days.

A 28-year veteran with the RRC, Doshier said the department had four employees when it was established in 2021. It now has 95, about two-thirds of whom are inspectors.

"Just like with you guys, whenever you're talking about the amount of critical facilities or critical components that you had to identify," she said, addressing her audience, "that's the same thing with us. We go out to an oil lease and there's 100 wells. We've got a great group of folks. These folks took on the challenge and they've done a really fantastic job."

"There's always something to be learned about how we operate in extreme conditions," the Texas RE's chief engineer, Mark Henry, said. "We saw, not unexpectedly, a number of unit issues much, much lower than what we saw in Uri, which is testament to the effectiveness of the actions that have been taken since … Uri."

Henry said NERC's recently revised *guidelines for generation units' winter readiness* include a collection of recommended industry practices. Incorporating those practices is strictly voluntary, he said.

The PUC has added a rule this year for additional emergency preparation measures "reasonably expected to ensure sustained operation" at the 95th percentile minimum average 72-hour wind chill value, effective Dec. 1. That rule is stronger than NERC's draft reliability standard (EOP-012-1) that requires generators with a commercial operation date after the standard's effective date to use freeze-protection measures capable of the unit's continuous operation for at least 12 hours. ■

ERCOT News

ERCOT Expects Sufficient Capacity this Fall

Final SARA Report Says 99 GW Available for Peak Periods

By Tom Kleckner

ERCOT said Sept. 19 that it expects to have sufficient capacity to meet peak demand under normal conditions during the two-month fall season that begins in October.

According to the Texas grid operator's *fall seasonal assessment of resource adequacy* (SARA), demand is expected to peak at 69.65 GW, a welcome relief after load averaged more than 80 GW over 227 hourly intervals during what has been brutal summer weather. The SARA indicates 99.73 GW will be available to meet demand in October and November.

That includes 3.99 GW of energy storage resources that have been invaluable in meeting record summer demand. A little over 1 GW of storage is assumed to be able to provide energy during the highest fall net load hours (total load minus wind and solar generation).

ERCOT said the estimated storage capacity is a proxy for what it expects during tight reserve hours and an interim availability assumption until a formal capacity contribution method is adopted in future SARA reports.

Solar energy, which played a key role during this summer's tightest hours, is expected to contribute 11.66 GW during peak periods this fall with a 64% seasonal rating. Wind energy is expected to contribute 12.69 GW during those periods; it has seasonal capacity factors ranging from 31 to 41%.

The assessment includes a base scenario and three elevated and three extreme risk scenarios reflecting alternative assumptions for peak demand, unplanned thermal outages and renewable output. The most severe extreme risk scenario — a combination of high peak load, high unplanned thermal outages (more than 18 GW) and extreme low wind output — results in a high risk of rotating outages.

An elevated risk scenario with low renewable output results in a capacity shortfall of 2.44 GW and close to a Level 1 energy emergency alert.

The grid operator said the SARA does not reflect pending changes that will come when the Texas Public Utility Commission approves a protocol revision (*NPRR1176*) that modifies the EEA level triggers.

The fall assessment marks ERCOT's final SARA report. It is being replaced with what the grid operator calls the monthly operational assessment of resource adequacy (MORA). The revised report will be posted two months before the reporting month, beginning with the December assessment on Oct. 2.

The first MORA will be produced manually but will eventually transition into a multi-tabbed spreadsheet that will include a link to an interactive dashboard. ■

Solar energy is expected to produce about 12 GW during peak periods this fall. | *Vistra Corp.*

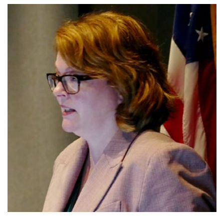
ERCOT IMM Raises Concerns over Newest Ancillary Service

ECRS Has Cost $608M Since June, Monitor Says

By Tom Kleckner

ERCOT's Independent Market Monitor says the grid operator's recent implementation of its first ancillary service in 20 years has nearly doubled the amount of required online reserves, resulting in "enormous" increases in market costs and shortage pricing when the market is long.

Carrie Bivens, the IMM's vice president, told stakeholders Friday that procuring and deploying the ISO's newest *ancillary service* (AS), ERCOT contingency reserve service (ECRS), has reduced supply and liquidity in the day-ahead market and "significantly" raised demand for AS products. That has resulted in inefficient day-ahead AS price spikes, she said.



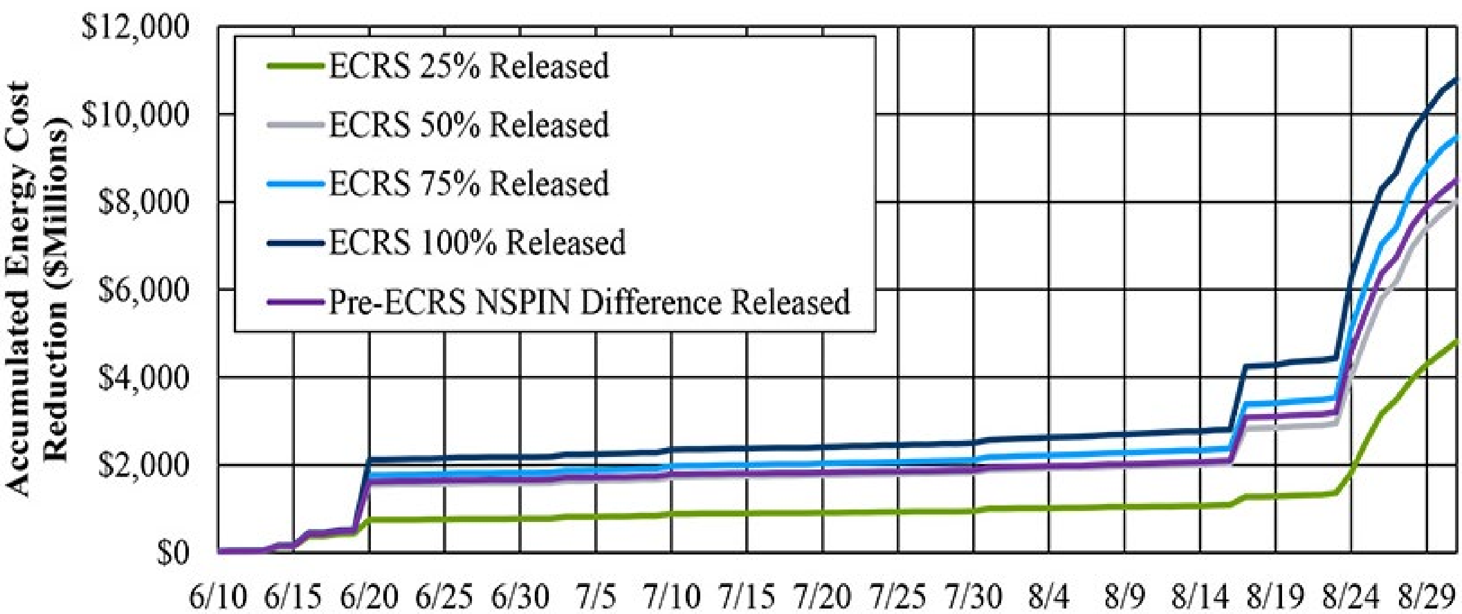
Carrie Bivens, Potomac Economics | *© RTO Insider LLC*

"We're seeing a disconnect between the operational realities and the pricing outcomes," she said during a Wholesale Market Working Group meeting. "It's also causing reliability issues, in our opinion, by increasing the challenges with managing congestion because fewer megawatts are available for scheduled dispatch to manage congestion … we've seen that on a few days you're seeing a huge increase in market costs."

AS services have incurred $1.56 billion in costs this year through August, Bivens said. ECRS, which began June 10, is responsible for almost 39% of those costs, or just over $608 million.

She said while the costs are substantial, they are much lower than the effects of removing the additional reserves from real-time market dispatch. Increasing online reserve procurements with ECRS "likely" raised the real-time market's energy value by $8-10 billion in three months, Bivens said.

"Price spikes in the day-ahead market are not necessarily reflective of the underlying conditions," she said. "The huge costs that we are really keying in on are the ones from [the] real-time market by removing those reserves. Taking megawatts that would have been avail-



	25% Released	50% Released	75% Released	100% Released	Pre-ECRS NSPIN Difference Released
June	-$774,345,448	-$1,587,969,782	-$1,823,128,056	-$2,183,715,958	-$1,670,295,524
July	-$230,429,049	-$303,797,235	-$356,456,936	-$388,845,385	-$272,166,972
August	-$3,818,750,565	-$6,132,111,308	-$7,303,871,948	-$8,236,831,344	-$6,557,867,403
Total	**-$4,823,525,063**	**-$8,023,878,324**	**-$9,483,456,940**	**-$10,809,392,687**	**-$8,500,329,899**

Simulated energy cost increases from higher online reserve procurements June 10-Aug. 31, 2023. | *Potomac Economics*

ERCOT News

able for energy dispatch and making them unavailable is reducing the supply available … that is causing this increase in real time energy prices, even though we have tons of reserves."

The new AS is economically dispatched within 10 minutes of deployment, using capacity that can be sustained at a specified level for two consecutive hours. ECRS essentially meets the same reliability requirements that previously were met solely by responsive reserve service (RRS), the IMM pointed out.

ECRS has resulted in a 2,500-MW increase in online reserve procurements, moving the MWs behind the high ancillary services limit (HASL). Bivens says that has resulted in artificial pricing shortages when total reserve levels are high and a negative effect on congestion management, as more MWs needed to address congestion are reserved for ECRS or RRS.

She said the artificial tightness is "episodically mitigated" by the operators' deployments, which interferes with day-ahead market decisions, whether to self-commit resources in real time and resource offers — all of which are based on expectations of real-time prices.

IMM staff arrived at the $8-10 billion figure by simulating the real-time energy market with reconstructed offer curves for lower ECRS procurements. Their analysis cleared the input MW quantity at the generation requirement's original SCED execution. Once a baseline scenario was done, staff modeled incremental 25% releases of ECRS in subsequent scenarios and calculated energy cost reductions.

Real-time ECRS deployments were maintained so that none of its additional capacity was released if deployments exceeded the release percentage. The simulation did not model congestion, ramp limitations, controllable load resources' dispatch or the power balance penalty curve.

"We wanted to show is this a small problem or is this a big problem?" Bivens said. "This is an order of magnitude type of analysis and what this is showing is that indeed it is a large problem."

Jeff Billo, ERCOT's director of operations planning, pushed back against Bivens' presentation and the IMM's call for a holistic review of ECRS, among other recommendations. He acknowledged inefficiencies and additional market costs but said ERCOT is getting the reliability it needs.

"When I look at the data that was presented, I don't see anything that backs up those recommendations other than ancillary services are really expensive or they're causing outcomes in the market that are really expensive. I don't see any data showing that we're getting more than we actually need," he said. "I also don't agree with the term artificial scarcity because this is a reserve product that we are buying, so it is meant to be held in reserve. It's not artificial, it is on purpose. We are reasonably reserving megawatts that we may need for various conditions that may occur on the system."

"I think we just want to make sure that you're buying what you need to be reliable, and no more than that," Bivens responded. "And also, I think we need to ask the question of the ECRS that we got this summer, 'Was it worth $10 billion?' That's something that I think I would ask people to think about.

"A lot of these megawatts, particularly during the summer, they're going to be online anyway," she added. "All you're doing, and why I'm calling it 'artificial scarcity,' is you're taking megawatts that would have been online for energy and putting them behind the HASL. And that's what's causing the cost increase. It's not that we're getting more megawatts. It's just how we're treating them."

The IMM recommends ERCOT reduce the ECRS' two-hour duration requirement to a single hour to encourage more storage participation. Its other recommendations include:

- Reducing ECRS' frequency recovery MW procurement;
- Removing the 2,800-MW floor on RRS;
- Changing the non-spin error requirement from six hours ahead to three; and
- Using 10-minute ahead net load errors for ECRS methodology.

The recommendations are based on the 2023 AS methodology and will be updated when ERCOT staff publishes its 2024 *proposal* for the services, Bivens said.

The Texas grid operator *launched ECRS* in June. It was the first daily-procured ancillary service introduced to the market in more than 20 years.

ECRS' development began as a *protocol change*, approved in 2019, designed to address forecasting errors from the increased penetration of renewable resources or to replace deployed reserves. The change also modified responsive reserve service to be primarily a frequency response. ■

ISO-NE News

ISO-NE Must Include Pumped Hydro in Inventoried Energy Program, FERC Rules

By Jon Lamson

ISO-NE must include pumped storage resources in its Inventoried Energy Program (IEP), FERC ruled on Thursday, siding with Brookfield Renewable Trading and Marketing in the company's complaint against the RTO (*EL23-89*).

The IEP is intended to compensate resources for storing extra fuel that they would not otherwise procure during periods of winter reliability risk. (See *FERC Approves Updates to ISO-NE Inventoried Energy Program*.) The D.C. Circuit Court of Appeals ruled in 2022 that the IEP cannot extend to nuclear, coal, biomass and hydroelectric resources because the program would not result in a change of their fuel storage behaviors.

Following the D.C. Circuit ruling, ISO-NE submitted — and FERC approved — a version of the IEP which excluded the specified resources, including pumped storage. Brookfield Renewable, which operates a 633-MW pumped hydro storage *facility* in western Massachusetts, filed a complaint over the exclusion of the resource type in August.

In FERC's ruling on Thursday, the commission said that the D.C. Circuit ruling does not preclude the inclusion of pumped storage because these facilities fall under the category of electric storage facilities, which are allowed to receive payments in the IEP.

"As the ISO-NE tariff currently permits battery storage electric storage facilities to be eligible to participate in the Inventoried Energy Program, it is unduly discriminatory to prohibit

Brookfield Renewables' Bear Swamp hydro project | *State of Massachusetts*

pumped storage electric storage facilities, which similarly store energy to later inject the energy into the system, from being eligible to participate in the Inventoried Energy Program and receive those payments," the commission wrote.

FERC wrote that IEP payments would likely incentivize pumped storage facilities to alter their behavior and boost reliability in the region.

"Allowing pumped storage electric storage facilities to be eligible to participate in the Inventoried Energy Program, similar to other electric storage facilities, can alter their incentives and thus their behavior by providing an incremental financial incentive to store energy," the commission wrote in the Sept. 21 ruling.

FirstLight Power and the New England Power Generators Association both submitted comments in August supporting Brookfield's complaint, while a group of consumer-owned power companies opposed it.

The consumer-owned power companies argued that the complaint was attempting to relitigate previous findings and that including pumped storage in the IEP would not result in more stored energy.

"Brookfield's complaint fails to show that any system-wide incremental energy production would result from extending the IEP's incentive compensation mechanism to pumped storage hydro facilities," the group wrote.

In its complaint, Brookfield argued that pumped storage operates in the same way as any other type of electric storage.

"The fact that one ESF [electric storage facility] may use pumped storage technology and another ESF may use a chemical battery is irrelevant because they both are able to provide the identical winter reliability service through the IEP," Brookfield wrote. "Because all ESF technologies operate under the same economic principles, the same incentive exists for all ESFs to provide reliability service through the IEP."

ISO-NE told FERC that it did not oppose the inclusion of pumped storage in the IEP but said it believed the D.C. Circuit ruling prevented their inclusion in the program.

"The D.C. Circuit's Belmont decision did not differentiate between pondage and pumped hydroelectric resources, but instead simply indicated that 'hydroelectric' resources must be excluded from the IEP," ISO-NE wrote. "The Belmont court did not provide any exception for pumped hydroelectric resources to participate in the IEP as ESFs."

ISO-NE had said it needed FERC order by Sept. 22 to include pumped storage in the IEP for the upcoming winter. ■

ISO-NE Sees Little Shortfall Risk for 2032

By Jon Lamson

There is little risk of energy shortfall in the summer of 2032, ISO-NE told the NEPOOL Reliability Committee (RC) on Sept. 19, building upon the RTO's previously released 2032 winter *results* that gave mixed signals on the system's reliability.

ISO-NE told the RC the shortfall risk for the summer of 2032 appears to be similar to that of summer 2027. (See *No Shortfall Anticipated for Summer of 2027, ISO-NE Says.*)

"No energy shortfall was observed in any of the summer 2032 events; only one hour of 30-minute reserve shortfall was observed in one July 13, 1979, case and in one July 26, 1984, case," Stephen George of ISO-NE said.

These *results* are part of ISO-NE's ongoing "Operational Impacts of Extreme Weather Events" study, which the RTO developed in conjunction with the Electric Power Research Institute.

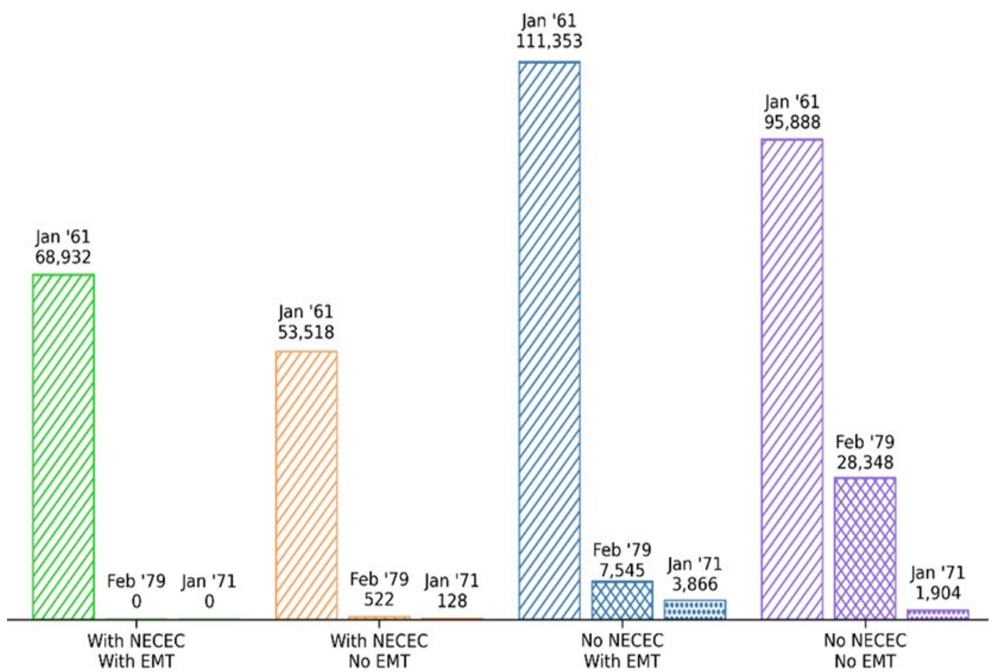
ISO-NE's baseline winter 2032 analyses projected worst-case energy shortfall risk to decrease in 2032 compared to 2027 in most scenarios. However, a sensitivity analysis — which considered an additional range of factors — showed increasing risks for 2032 compared to 2027.

The baseline analysis indicated winter shortfall risks significantly decreased with the presence of the New England Clean Energy Connect (NECEC) transmission line, while the Everett Marine Terminal actually increased shortfall risk in most of the scenarios modeled. ISO-NE said it expects the 1,200-MW NECEC line to be in service by 2032, while the future of Everett remains in limbo. (See *Narrow Set of Options for Retaining Everett LNG Terminal.*)

"In terms of magnitude and probability, baseline studies of 2032 winter events indicate an energy shortfall risk profile similar to that of the 2027 winter event studies," ISO-NE said in August about the 2032 winter modeling.

However, the RTO noted that the "sensitivity analysis of 2032 worst-case scenarios indicate an increasing energy shortfall risk profile between 2027 and 2032," adding that the increased risk "is particularly observable with the 2023 CELT (Capacity, Energy, Loads, and Transmission) load forecast."

The 2023 CELT *forecast* increased the projected electricity demand for the 2031/2032 winter by about 10% compared to the 2022 CELT *projection.* (See *ISO-NE Increases Peak Load Forecasts.*) The baseline analyses were run using the 2022 CELT data.



Worst-case energy shortfall in winter of 2032 modeled based on historical extreme long-duration winter weather events. | *ISO-NE*

The winter 2032 sensitivity analysis used the worst-case weather event modeled in the baseline analysis, while varying the levels of resource retirements, electricity demand, imports, stored fuel inventories and forced outages. ISO-NE told the RC that sensitivity analysis results for the summer of 2032 will be shared at a future meeting.

These reliability findings come as ISO-NE grapples with increasing levels of variable renewable generation coupled with a massive expected increase in electricity demand stemming from electrification. ISO-NE expects the regional grid to transition from a summer peak to a winter peak at some point in the coming decades, in part because of heating electrification.

EMT, which is the only LNG import terminal in New England, is propped up by the expensive Mystic Agreement, which will expire after this winter. ISO-NE's quantitative analyses have not shown that the terminal is necessary for grid reliability, but the RTO has maintained the facility may be needed in the future in the face of rising winter demand and reliability concerns.

"I think it would be extremely unwise were we to let that facility go until we know where we are with regard to these variables," ISO-NE CEO Gordon van Welie said at a FERC forum on winter reliability in June. (See *NE Stakeholders Debate Future of Everett at FERC Winter Gas-Elec Forum.*)

ISO-NE is conducting another round of sensitivity analysis for the winter of 2032, which will consider a range of factors and assumptions based on feedback from NEPOOL stakeholders. These added sensitivities will include varying levels of renewable generation, battery storage, behind-the-meter solar, demand response, imports, and gas, oil and nuclear resource retirements.

The RTO will discuss the results of this additional sensitivity analysis at the November RC meeting. ■

ISO-NE News

New England TOs Propose Asset Condition Project Database

Call for Age, Structure Number, Other Data Comes amid Increasing Repair Needs

By Jon Lamson

| © RTO Insider LLC

The New England Transmission Owners outlined a proposal for a new asset condition project database at ISO-NE's Planning Advisory Committee on Wednesday.

The proposal came in response to requests from the New England States Committee on Electricity (NESCOE) for broad changes to the asset condition project process. (See *States Press New England TOs on Asset Condition Projects*.)

Asset-condition projects target existing transmission infrastructure that is aging, defunct or otherwise in need of repair. Costs for asset condition projects in New England have ballooned in recent years and now make up the majority of new transmission spending in the region.

The proposed database would provide ISO-NE and the public with information on age, number of structures, inspection timing, and structure material and construction type for pool transmission facility (PTF) lines. The database would also provide new information on transformers including operating voltages, age, and testing and inspection information.

The TOs' presentation noted that future additions to the database could include metrics on asset health, more granular data on the age of structures and information on other PTF infrastructure, including control houses, circuit breakers and relays.

"We wanted to provide something that is impactful by the end of the year, and we will look into providing information on some of these additional elements at a later time," said Eversource Energy's Robin Lafayette, also representing TOs Avangrid, National Grid, Rhode Island Energy, VELCO and Versant Power.

Lafayette added that developing the asset health metric will take some time and that the TOs will need to be sensitive regarding confidential infrastructure information.

In a July *letter* to the TOs, NESCOE wrote that the "database should provide a comprehensive view of all information necessary to guide and inform holistic asset condition prioritization and decision-making."

Beyond the database, NESCOE also recommended that the TOs develop asset condition project spending plans, standardize the stakeholder review process and develop a criteria-based approach for asset condition solutions.

"The pace and scale of recent asset condition projects demonstrate the time urgency of such reforms," NESCOE wrote. "By taking time now to slow down and establish a transparent and predictable asset condition process, New England can move toward work on a right-sizing approach — an important part of holistic planning that will allow for efficient transmission investment at the pace and scale needed for the region's clean energy future." ■

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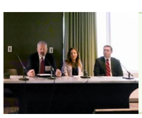
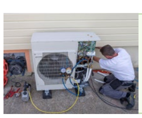


Northeast Stakeholders Discuss The Future of Alternative Fuels NetZero Insider



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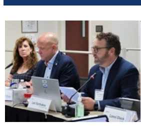

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MISO News

MISO Relaxes Proposal on Stricter Queue Ruleset

By Amanda Durish Cook

MISO convened a special meeting last week on its plan to downsize the number of projects allowed in its generator interconnection queue.

Since last month, the RTO has pared down proposed fees for projects to enter the queue and penalties assessed upon dropping out.

MISO intends to place an annual megawatt limit on project proposals, collect higher entry fees, enact escalating penalty charges and require developers to verify they have obtained land. RTO planners have said the plan will ensure that only the most prepared projects will have a spot in the queue and reduce speculative projects that drop out and gum up network upgrade studies. (See *MISO Sticks with MW Caps, Higher Fees to Pare Down Queue Requests*; *MISO Aims for Manageable Interconnection Queue*.)

Now, the grid operator has cut back its first milestone fee paid to enter the queue from a proposed $10,000/MW to $8,000/MW. The fee currently stands at $4,000/MW; MISO first proposed to increase the fee to $12,000/MW in summer.

"We don't plan to lower it any more. We think 8K is on the low end," MISO's Andy Witmeier told stakeholders.

Witmeier also said MISO has lowered its automatic penalty schedule so it can hold onto 10% instead of 25% of the first milestone fee at the queue's first decision point and 35% instead of 50% by the second decision point.

The remainder of MISO's automatic penalty structure proposal remains unchanged for the final two penalty points. A developer will still risk 75% by the time their project reaches the third and final phase of the queue and, finally, 100% if they drop out during the negotiation stage of the generator interconnection agreement.

Witmeier said MISO supports interconnection customers deciding to withdraw their projects as soon as they know they're infeasible rather than lingering in the queue.

"I think we're honing in on a really good proposal that we can bring to FERC in October," Witmeier said.

MISO's interconnection queue now stands at more than 240 GW across more than 1,400 projects.

MISO has a goal to file before the end of October, so its proposal is registered with FERC before the commission's Order 2023 takes effect Nov. 5. Although MISO considers its proposal separate from Order 2023, the grid operator isn't certain how the final rule will interact with the tightening of the MISO queue.

However, MISO still is working out how it will calculate its yearly megawatt cap on interconnection requests.

"We all agree we have a math problem here" in terms of how many projects MISO can realistically study, Witmeier said.

He added that MISO's cap will include a "safety valve" feature that will allow developers to exceed the cap when projects are intended for load serving obligations, have a power purchase agreement, are an approved generator replacement facility or when projects simply are requesting to convert their unguaranteed level of interconnection service to firm service.

Consulting firm Charles Rivers Associates (CRA) reached similar solutions to help control MISO's queue stampede.

MISO enlisted the help of CRA to review independently how MISO can best cut down on both its queue size and rate of withdrawals.

CRA concluded MISO should raise its first milestone fee from $4,000/MW to anywhere from $10,000 to $14,000/MW, install queue entry caps and enact an escalating fixed penalty schedule and a minimum penalty at every stage for withdrawing projects.

"After years of remaining relatively stable, the MISO queue has inflated to unmanageable levels in recent years," CRA's Margarita Patria said.

Patria said CRA's recommendations strive to incentivize customers entering the MISO queue only after "really careful consideration."

Patria said there "should be some consequences" for withdrawing projects because it's a reality that withdrawing projects negatively impact other projects, even though the dollar amount is difficult to quantify.

Witmeier said MISO agrees its "pre-queue activity" needs to improve, as stakeholders have suggested. He said MISO plans to improve its existing point of interconnection tool to consider active interconnection requests and give developers a better idea of the feasibility of their projects.

He also said MISO plans to hold more informative scoping discussions with developers, use advanced analytics to share data on projects progressing in and exiting the queue alike and is considering using interactive AI chat bots to answer developers' questions about MISO's queue rules. ■

EDF Renewables' Sandoval solar project in Illinois was completed in 2021. | *Soltage*

MISO News

NIPSCO Proposes New Gas Plant; Ind. Consumer Advocate Displeased

Advocate Program Director Notes Multiple Problems, Including with Costs

By Amanda Durish Cook

Tensions are building over Northern Indiana Public Service Co.'s proposal last week to build a new natural gas peaking plant at its R.M. Schahfer Generating Station.

NIPSCO filed for permission with the Indiana Utility Regulatory Commission (IURC) to install a 400-MW, $643.7 million natural gas plant (*45947*). According to NIPSCO, the plant would be in service at the end of 2026 and replace two soon-to-be retired coal units at the Schahfer station. The utility intends to transfer the retiring units' interconnection rights on the MISO transmission system to the new plant.

The utility is also proposing to use construction while in progress (CWIP) ratemaking, which would allow it to start billing customers for the plant prior to construction and commercial operations.

The Citizen Action Coalition of Indiana, an environmental and consumer advocate, says the new plant will be costly, unnecessary and detrimental to the clean energy transition.

Ben Inskeep, program director at CAC Indiana, *said* NIPSCO's proposal means it has "backtracked" on its 2018 integrated resource plan, which saw no need for new fossil fuel plants.

"One of the troubling aspects of NIPSCO's certificate of public necessity and need filing for up to 442 MW of new gas turbines is that it is inconsistent with its current IRP," Inskeep said in a statement to *RTO Insider*. "NIPSCO's 2018 IRP found that no new fossil gas resources were needed. NIPSCO's 2021 IRP included a preferred plan that has 'up to 300 MW' of new gas. However, NIPSCO unilaterally and without stakeholder input conducted additional analyses after it completed its 2021 IRP that it now claims supports its decision to increase its new natural gas capacity by 47% relative to its most recent IRP."

NIPSCO insists the gas-fired plant is necessary and said its addition was previously contemplated in its 2021 IRP. The utility said by the time it retires all its coal-fired generation in 2028, renewable energy will begin to dominate its energy mix, and it will need a source of flexible generation during peak energy use and extreme weather conditions in the winter and summer.

NIPSCO spokesperson Tara McElmurry said the utility requires a new gas-fired peaker to "support system reliability and resiliency, along with public safety, as part of a cleaner and more balanced energy mix for the future."

"NIPSCO is committed to creating a reliable, sustainable supply of energy that will serve customers — both now and in the future," McElmurry said in a statement to *RTO Insider*. The peaker will run only when necessary and act as a "bridge for the generation gaps of more intermittent energy sources." She said NIPSCO's goal to achieve net-zero carbon emissions by 2040 remains unchanged, and it will have the option to convert the plant's fuel source to hydrogen in the future.

In testimony to the IURC, NIPSCO Vice President of Power Delivery David Walter said he is aware "some stakeholders would prefer that NIPSCO only implement renewable generation resources going forward." However, he said that is not the most prudent option and that the plant will be "at least partially responsible for unlocking the long-term customer savings that are expected from NIPSCO's overall generation transition."

NIPSCO said its need for a peaking plant was emphasized through an updated portfolio analysis this year that "incorporated market shifts and changes" since its 2021 IRP. The utility included the effects of inflation, MISO's new seasonal capacity market design and availability-based capacity accreditation, passage of the Inflation Reduction Act, and portfolio needs under the clean energy transition.

But Inskeep said NIPSCO shouldn't be spending "exorbitant sums of ratepayer dollars to build more fossil fuel infrastructure that will hardly ever operate." He said he is unconvinced NIPSCO needs a "massive expansion of natural gas" and that it did not adequately consider energy storage with grid-forming inverters, demand response or purchases from the MISO markets before it issued a request for proposals for thermal generation only.

NIPSCO maintains that using its existing facilities and some existing equipment at the Schahfer station will save customers money.

Inskeep also said CAC is "highly alarmed at the extraordinary expense" of the new units and the direction NIPSCO is taking on construction and financing.

R.M. Schahfer Generating Station | *NIPSCO*

NIPSCO rejected all three bids in response to its RFP. It was ultimately unable to land on an affordable engineering, procurement and construction agreement with an outside party, and plans to self-build the project.

Inskeep said the self-build prospect is a risky bet for ratepayers. He pointed out that, according to staff testimony, NIPSCO has not ventured into self-building a gas plant before. He also criticized NIPSCO's plan to use CWIP, saying it is inappropriate for utilities to pass costs onto customers before they even incur them.

"Ratepayers will be paying for the gas turbines before they are used and useful, and even if they never generate any electricity. CWIP has a notorious reputation in utility ratemaking for harming ratepayers by shifting project risk from utility shareholders onto ratepayers," Inskeep said.

NIPSCO can file to charge customers in advance of the project under a "clean energy" designation because the Indiana legislature *passed* a bill this year allowing utilities to use the financing option when they construct new natural gas plants that displace coal. ■

MISO News

MISO Charting Course on Stimulating Generating Attributes

By Amanda Durish Cook

MISO last week said it continues research to gauge the quantity of generating attributes it might prescribe for its fleet.

MISO has defined six system reliability attributes as necessary, including availability, rapid start times, the ability to deliver long-duration energy at a high output and providing voltage stability, ramp-up capability and fuel supply certainty. (See *MISO Considers Resource Attributes as Thermal Output Falls*.) The RTO is studying what role it can play in maintaining those increasingly scarce reliability attributes from generation in the long term.

The RTO will share what changes it thinks might be necessary in an action plan it plans to publish at the end of the year.

"A growing body of experiences in MISO and across the industry has led MISO to focus on ensuring reliability system attributes are understood and maintained," Director of Policy Studies Jordan Bakke said during a Sept. 21 stakeholder workshop.

Bakke said MISO can learn and borrow solutions from smaller countries and how they've approached ensuring attributes. He said EirGrid in Ireland has similar challenges with its transitioning resource mix.

MISO's Patrick Dalton said the strength of MISO's system can be thought of as a trampoline that's slowly losing spring because intermittent resources aren't replacing the characteristics of baseload generation.

Bakke said less predictable weather paired with less predictable generation means MISO must focus on supplying energy for the worst week in every season instead of just the worst peak load in the summer.

Michael Milligan, a consultant to GridLabs, asked how MISO will calculate the quantity of attributes necessary while tracking the rate that MISO is losing them.

"That is our intent, and that's inherently difficult to do as we've learned over the last several months," Bakke said. However, he said landing on specific amounts of attributes is "core" to what MISO is trying to accomplish.

Minnesota Public Utilities Commission staff member Hwikwon Ham said states need in-depth information as early as possible on how MISO plans to measure needed attributes so commissions can integrate them in state-level resource planning.

WEC Energy Group's Chris Plante pointed out that MISO already has incorporated and is planning major resource adequacy changes, including capacity accreditation, a seasonal capacity auction design and sloped demand curve in the auction. He said those changes are driving a "fundamental change" in how resource planners approach generation planning. He said planners have reverted to an older style of resource planning, where they ensure they own energy adequacy and rely less on the MISO markets.

"I think it's important that we keep that in mind that the shift is already occurring," he said.

Plante also said new planning might mean MISO's middle-of-the-road transmission planning future, which it's using to analyze attributes, might be outdated in light of the new, more independent style of resource planning.

IMM Skeptical

MISO Independent Market Monitor David Patton repeated his reservations with MISO's accreditation work at a Gulf Coast Power Association virtual forum Sept. 15.

"I don't oppose the work in general, but I do oppose the notion of singling out specific attributes and identifying a megawatt quantity that's needed because it points to the wrong solution, which is we should create products related to these attributes," Patton said.

Instead, MISO should put more emphasis on applying marginal capacity accreditation with sound modeling behind it, Patton said. He said MISO will naturally entice units with reliability attributes if it portions out capacity credit based on how nimble and stable generators are.

"Units with good attributes will get high accreditation, and units with attributes that don't help you much from a reliability standpoint will get low accreditation levels," Patton said.

MISO has planned another attributes discussion during a dedicated Oct. 31 workshop, then again at the Nov. 8 Resource Adequacy Subcommittee. ■

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

MISO News

MISO Postpones Meeting for More Analysis on Entergy Expedited Substation Work

By Amanda Durish Cook

MISO announced it's pushing back a scheduled meeting to discuss three new substations proposed by Entergy for expedited treatment in the RTO's annual planning cycle.

The grid operator said it needs the pause to conduct more analysis on the trio of expedited projects to serve new load interconnections near Jackson, Miss., before it can recommend the projects move ahead.

Entergy proposed three new substations for the fast-growing industrial area of Madison County in August. It sought MISO go-ahead to build two new 230-kV substations to serve 267 MW in load apiece and a 500/230-kV substation to cover 537 MW in new load.

Entergy wants to bring the 230-kV substations online by early 2025 and 2026. The utility envisions the 500/230-kV substation to be operational by mid-2027.

But MISO said the "size and complexity" of the new projects means it was forced to postpone its Sept. 22 South Technical Study Task Force meeting, where it was due to discuss study results with stakeholders. MISO studies expedited project requests for adverse impacts on its system.

MISO said its review uncovered transmission issues were the proposed substations to be built. The RTO said its expansion planning team now must work with affected transmission owners to resolve the issues and said it will schedule a new task force meeting once it can complete its review.


Entergy Mississippi substation | *Malouf Construction*

MISO has been fielding numerous and more complex out-of-cycle requests for projects that can't wait to begin construction until the early December approval typically reserved for the MISO Transmission Expansion Plans (MTEPs).

The grid operator has said the surge in expedited project review requests means it needs to modify its expedited study procedures so its planners won't be overwhelmed. (See *MTEP 23 Catapults to $9.4B; MISO Replaces South Reliability Projects*.)

MISO also said it expects load growth driven by large industrial and commercial interconnections to continue for the foreseeable future. (See *MISO: Expect More Expensive Annual Transmission Packages*.) ■

MISO News

FERC OKs MISO Removal of Annual Reviews for Long-term Tx Projects

By Amanda Durish Cook

MISO is off the hook for having to conduct annual cost-benefit analyses of its major transmission projects, FERC has ruled.

FERC on Friday allowed MISO to cut the portion of its Tariff requiring it to conduct annual benefit reviews of its long-term transmission projects. The RTO still will conduct its more comprehensive triennial reviews (*ER23-2478*). The commission's approval was effective Sept. 24.

FERC said it was persuaded the annual reviews "have become less useful over the years given the development of alternative sources of similar information." The commission said it didn't think the discontinuation of the reviews would affect project transparency in MISO.

In July, MISO proposed eliminating the four limited annual reviews required of it for long-term transmission projects. That will leave MISO conducting two triennial reviews of projects following project approval. MISO said the move will "drive administrative efficiency for MISO, its stakeholders and regulators."

According to MISO, removing the limited reviews will allow it to spend more time planning portfolios of other long-range transmission projects. It also said the annual reviews usually only uncover "minimal data changes" year-over-year and said info on transmission projects' progress is available to stakeholders on its website, through its MISO Transmission Expansion Plan (MTEP) quarterly status updates and contained in its variance analyses. MISO performs variance analyses on projects only when they materially change in cost, schedule or design from MISO approval.

MISO's triennial review requires it to calculate economic benefits of major projects, such as congestion and savings and the ability for the RTO to carry a smaller amount of reserves. It also requires MISO to evaluate achieved public policy targets, like the amount of new renewable energy the line can bring to the system, and perform five-year historical examination of the line's effect on the fleet mix, interconnection trends, energy prices, fuel costs and margin requirements.

On the other hand, the limited reviews required MISO to calculate the latest data available of the economic benefits and five-year historical trends.

The Organization of MISO States supported MISO's pruning of reviews, saying its remaining reporting requirements are sufficient to stay up to date on transmission projects. However, the group of state regulators requested FERC order MISO to "consistently and accurately" update its long-range project dashboard and quarterly status reports on its MTEP portfolios to ensure they're useful. OMS said MISO has been inconsistent in updating actual project costs and in-service dates, which limits regulators' ability to question transmission developers' cost containment efforts.

FERC, however, said the OMS concerns were beyond the scope of the proceeding and declined to address them. MISO said FERC should disregard the OMS request because it's already working to upgrade its admittedly outdated MTEP project portal, the database it maintains for approved projects. ■

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NYISO News

NYISO Discusses Enhanced Regulations for Information Sharing

Stakeholders Updated on System & Resource Outlook Next Steps

By John Norris

RENSSELAER, N.Y. — NYISO soon could significantly tighten its security and information protection requirements, according to a *presentation* given to stakeholders last week.

Troutman Pepper, an energy law firm, advised the Transmission Planning Advisory Subcommittee and Electric System Planning Working Group meeting that as digitization grows, enhancing NYISO's critical energy and electric infrastructure information (CEII) protection has become increasingly important.

Kat O'Konski, an associate at Troutman Pepper, said, "there is a pressing need" to improve CEII requirements because both "physical and cyber assaults on the grid are at a record high." (See *Feds Charge Idaho Man in Dam Attacks*; *NERC's Cancel Details Grid Threats to House Energy Subcommittee*; *DERs' Deployment Leads to Increasing Cyber Threats*.)

Troutman wants to toughen measures around NYISO's data dissemination by requiring third parties working with and around the ISO's supply chain to implement more stringent protocols for CEII sharing and access.

These enhancements include mandatory cyber-training for certain workforces and obtaining cybersecurity risk insurance, as well as recommending that sensitive data be stored in multiple geographically isolated data centers to provide an added layer of redundancy.

Troutman requested that its proposals to tighten NYISO's security and information-sharing procedures be approved quickly but some stakeholders were skeptical about the proposed implementation timeline and whether the CEII protections were more restrictive than protective.

Doreen Saia, an attorney with Greenberg Traurig, said Troutman was unrealistic to expect its proposals could be approved before the end of the year, given the number of meetings and the upcoming holiday season, as well as considering the breadth of the proposal.

NYISO control room in Rensselaer, N.Y. | *NYISO*

Stu Caplan, partner at Troutman Pepper, asked what a realistic timeline would be. Saia responded that her firm would need at least a month or more to review the requirements, but that multinational organizations likely would need even more time to comply with the requirements, particularly those related to geographic data storage.

Glenn Haake, vice president of regulatory affairs at Invenergy, concurred with Saia, noting how multinational companies might struggle with these requirements, particularly if the rules vary by country of origin.

O'Konski sought to mollify these concerns by noting how Troutman's proposals are intended to create a single set of CEII standards applicable for everyone.

Kevin Lang, partner at Couch White, in reference to expanding the list of personnel required to obtain CEII clearance, said Troutman needs to consider that not every NYISO market participant has the same level of resources as transmission owners and to ensure its requirements are not preventing smaller businesses from accessing the ISO's data.

There was a consensus on the need for enhanced CEII protections and no one opposed the measures outright, but stakeholders wanted to guarantee a balance between security and accessibility.

Troutman will return with a more detailed proposal and requested feedback be sent to either Caplan or O'Konski by Sept. 28.

System & Resource Outlook

NYISO *updated* stakeholders that the base case lockdown date for the biennial System & Resource Outlook report has been set for Oct. 15.

The base case serves as the foundational set of initial conditions, scenarios and assumptions used in the Outlook's modeling.

The 20-year forecasting report examines how New York's transmission system develops, performs, and responds to the state's aggressive climate and energy legislation. (See "System & Resource Outlook," *NYISO Previews New York City Transmission Needs Assessment*.) ■

NYISO News

Champlain Hudson Converter Station Breaks Ground in NYC

Work also Underway on Clean Energy Hub for OSW Interconnection

By John Cropley

Two key pieces of New York City's clean energy future are taking shape along the East River waterfront.

The converter station for the Champlain Hudson Power Express and the Brooklyn Clean Energy Hub both hosted ceremonial ground-breaking ceremonies in the past week.

Both will play an important role in keeping the lights on in the city, but the need is more pressing for the CHPE facility in the Astoria neighborhood of Queens. NYISO has warned that further delays in the transmission project could worsen the reliability margin deficit the city faces starting in 2025.

Gov. Kathy Hochul (D), U.S. Department of Energy Deputy Secretary David Turk, Premier of Quebec Francois Legault and dozens of other officials gathered Sept. 19 to mark the start of work on the project.

CHPE is a 339-mile underwater and underground HVDC line that will carry up to 1,250 MW of power generated by Quebec hydropower plants to New York City. After more than a decade of planning and review, construction of the line began early this year.

Now, work has begun on the converter, which will occupy a former fossil fuel site. Six tanks that once held 12 million gallons of No. 6 oil were removed in the weeks before Tuesday's event, along with nearly four miles of piping.

Hochul said in a news release: "The transformation of a fossil fuel site into a zero-emission facility highlights the world of possibilities we have to reduce our dependence on fossil fuels, mitigate the impact of climate change and accelerate our collective progress of shifting our power grid to go green."

CHPE also will move New York state closer to its 2030 goal of 70% renewable power generation and will help fill the gap created by the mandated peaker plant retirements that NYISO has warned will create a deficit.

"The importance of the Champlain Hudson Power Express project to maintaining grid reliability and enabling the transition to the grid of the future cannot be overstated," NYISO President Richard Dewey said in a news release. "By delivering 1,250 megawatts of clean, renewable hydropower to the New York City metro area, this project plays a key role in the move to electrify the economy and meet the state's ambitious clean energy goals."

Work is shown Sept. 19 on the Champlain Hudson Power Express converter station in New York City. | *New York Governor's Office*

Seven miles south, in Brooklyn's Vinegar Hill neighborhood, Con Edison broke ground Sept. 12 on its Clean Energy Hub.

The facility eventually could serve as the interconnection point for up to 1,500 MW of the 9 GW of offshore wind power that New York state hopes to have online by 2035.

But there already is a pressing need for the Clean Energy Hub as a means of maintaining reliability, because the surrounding area is placing greater demand on the grid with electrification of buildings and transportation.

Con Edison expects demand in certain neighborhoods to exceed the existing infrastructure's capacity by 2028.

"The Brooklyn Clean Energy Hub represents a major milestone in the clean energy transition and will strengthen our grid's reliability," Con Ed CEO Tim Cawley said in a news release. "This project will offer a critical plug-in point to connect with offshore wind, while creating good jobs, supporting economic growth and advancing New York's climate goals."

The CHPE station stands in an area with multiple fossil-fired generating stations and resulting poor air quality. Con Ed's Hub also occupies the site of a former fossil-fire facility.

Neighborhood activists cheered the conversions.

Costa Constantinides, CEO of Variety Boys and Girls Club of Queens, said: "Today is a great day for the energy transition away from fossil fuels here in Astoria. For too long our community has borne the brunt of fossil fuel production and the health impacts that have turned our neighborhood into 'Asthma Alley.'" ■

NYISO News

NY Policy Council Holds Inaugural Meeting to Discuss CGPP

Predicts Higher Peak but Lower Annual Load; Stakeholders Ask About Modeling and Resources

By John Norris

New York agencies *revealed* updated modeling Sept. 19 indicating the state in 2050 could have a roughly 2 GW higher peak load but 4 TWh lower annual load than previously predicted (*20-E-0197*).

The Energy Policy Planning Advisory Council, which represents every energy sector and acts as an advisory board to the Public Service Commission, held its first stakeholder meeting to discuss the *Joint Utilities*' updated Coordinated Grid Planning Process and begin to implement the state's net-zero Climate Leadership and Community Protection Act.

The *CGPP* seeks to align New York's transmission system development with its emissions reduction goals, while attempting to control costs and speed up processes as the state ramps up its energy production and consumption. The PSC kicked off this two-year, six-stage planning process after approving the CGPP in August. (See *NY Creates Coordinated Grid Planning Process*.)

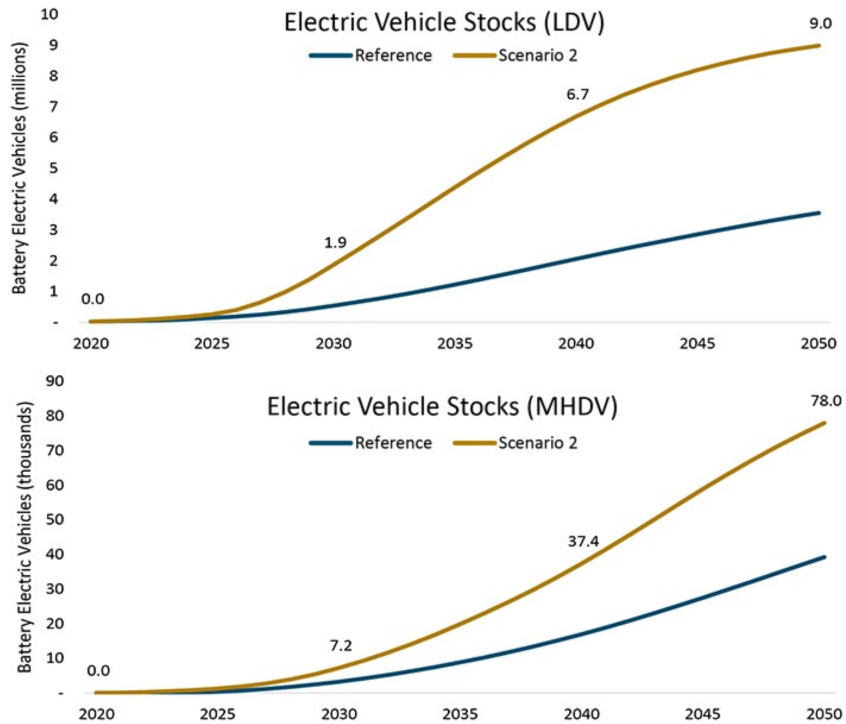
While the PSC will finalize the CGPP's framework, the EPPAC plays a key role in shaping the direction of the state's grid planning by providing recommendations.

The Department of Public Service and the New York State Energy Research and Development Authority staff presented updated results from the integration analysis, showing 2050 peak load would increase roughly 55% and annual load increase 90% over 2020 levels.

NYSERDA's IA is an economywide assessment supporting CLCPA implementation by modeling proposed emissions reduction and mitigation strategies and since has been modified to include updated *reports* from the Department of Environmental Conservation, as well as new sensitivity assumptions.

The updated outcomes show no significant impact on key topline cost and benefit metrics, but they do show some notable differences in predicted outcomes, including that New York's economywide electrification is driving higher peak loads but that these are offset by efforts to decarbonize the building and transportation sectors.

These offsets are seen in the modeling through greater representation of building



Projected annual load and peak for CGPP Scenario 2 to 2050 | *NYDPS*

heating upgrades, increased electric vehicle infrastructure and better accounting of the effective load carrying capacity provided by certain renewables.

The IA has modeled only Scenario 2 of NYISO's *System and Resource Outlook*, but staff emphasized this work is ongoing and they would return with more results from other modeled scenarios to help bound their assessments.

The CGPP has six stages, and the EPPAC is aligning multiple scenario forecasts and climate policy objectives, with the assumptions necessary to effectively develop its predictive modeling.

Elizabeth Grisaru of the DPS noted that the EPPAC operates on a tight timetable, with final CGPP recommendations due to the PSC for review July 1, 2025.

Therefore, the EPPAC is poised to meet twice a month with stakeholders to continue discussions.

Q&A

Stakeholders at the meeting had questions about both the updated CGPP modeling and staff's presentation.

A common theme centered on how resources like hydrogen, dispatchable emission-free resources and energy storage were treated in the CGPP's modeling and whether assumptions for these technologies were CLCPA-compliant.

Raya Salter, executive director of Energy Justice Law and Policy Center, said she worried staff were getting ahead of the PSC in determining "what should and shouldn't be considered zero emissions" and wondered if the modeled level of hydrogen penetration is consistent with the CLCPA. The PSC is debating what resources can assist the state in achieving its net-zero goals. (See *Contentious Commentary on Zero-Emissions Path in NY*.)

The IA models hydrogen as green hydrogen, meaning produced cleanly through electrolysis, but some attendees said they worried about whether the role of hydrogen was being overvalued in the modeling, in lieu of other renewables.

Nick Patane, senior project manager at NYSERDA, responded to this and similar hydrogen questions by clarifying that the model assumes 50% of hydrogen production occurs

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in-state and the other half is imported. He added that the IA models hydrogen as green hydrogen, meaning it is produced only cleanly through electrolysis.

Erin Hogan of the state's Utility Intervention Unit and William Acker, executive director of the New York Battery and Energy Storage Technology Consortium, had questions about DEFRs, and its related technologies, and whether these resources are being modeled correctly.

Hogan asked whether the IA accurately predicts the expected lifetime of certain intermittents, such as batteries, and if they are modeled in the state's future transmission system according to their expected lifetime. "We need to find a Goldilocks solution: We don't want to build too much, but we don't want to build too little, and we want to build it in the right place," she said.

Following this theme of nuanced transmission planning, Acker noted it's critical to accurately model DEFRs, since certain classes of these resources have different effects on the transmission and distribution system that must be accounted for when deciding where to install new resources or make system upgrades.

Kevin Steinberger, director of E3, which developed the modeling, responded that its model was built to be flexible to account for those resources, but added that his team has been comparing notes with NYISO to ensure compatibility.

Other stakeholders asked about the CGPP's modeling itself: how it was built, what its long-term implications for the state's climate goals are and whether more inputs would be added.

Hogan asked about the continuation of transmission costs and benefits beyond the model's study period.

Jason Frasier, senior manager of transmission planning at NYISO, responded that the ISO's Outlook, which is where the CGPP's modeling scenarios are pulled from, does not explicitly model beyond its study period but does have a perpetual setting that assumes the metrics from the final year are carried onward.

Hogan and others also asked if more scenarios would be added to IA, which staff confirmed was the case and that two more scenarios would be included in the CGPP's modeling, as well as other market sensitivities.

One final concern expressed throughout the discussion was the need for transparency and stakeholder collaboration.

Stakeholders sought to ensure they would be contributing meaningfully to the final CGPP product, and staff promised to ensure transparency where possible, though they did cite some instances where issues related to confidentiality may make this difficult, particularly as it relates to generator retirements.

Staff added that a dedicated EPPAC website would be created to make locating relevant materials easier. ■

FERC Approves PJM Cost Recovery for NERC Penalty

Danly 'Reluctantly' Concurs but Calls for Investigation

By Holden Mann

FERC ruled last week that PJM can go to its customers to recover a $140,000 penalty leveled against the RTO this year by ReliabilityFirst, with Commissioner James Danly "reluctantly" concurring but calling for an investigation into PJM's reliability violations and "manifest failures" to ensure reasonable electricity rates (ER23-2327).

PJM agreed to the penalty as part of a settlement with RF approved by FERC in April over several violations of NERC reliability standards — some at the Quad Cities and Dresden nuclear plants in Illinois, and others stemming from coordination issues at transmission facilities owned by FirstEnergy Utilities (NP23-13). (See PJM Hit With $140K Penalty for NERC Violations.)

According to a guidance order issued by FERC in 2008, RTOs and ISOs may "request recovery of penalty costs by spreading those costs among their members and/or consumers on a case-by-case basis." Such requests must meet several criteria to be eligible for commission approval, including:

- Whether the RTO or ISO involved had a compliance program in place.
- Whether the violations were due to intent or gross neglect.
- Whether management was involved in the violations.
- The ability of the organization to pay the penalty.
- The fairness of the RTO's or ISO's proposed assessment mechanism.

On June 30, PJM requested that FERC approve the recovery of the $140,000 RF penalty from its customers. The RTO explained that while it previously would have paid penalties from its administrative cost recovery rates, a change to its tariff in January 2022 meant the rates would no longer be "sufficient to absorb penalty costs."

PJM claimed its proposed recovery was consistent with the criteria in FERC's 2008 guidance order, noting that it possesses "a robust internal compliance program," that all the violations were inadvertent and no harm to the grid resulted, and that management was not involved in the violations. The RTO said its proposal would allow "a broad allocation of the costs," with a low impact on individual consumers; according to PJM, if recovered in a single month, the resulting additional cost to consumers would be around a fifth of a cent per MWh.

Public Citizen objected to PJM's request, stating that putting the cost of the penalty on consumers would be "unjust and unreasonable. Instead of recovering the cost from consumers, the consumer advocacy group suggested that "PJM executives and PJM's Board of Managers should be financially responsible for the penalties."

This approach would be consistent with a FERC ruling last year against ISO-NE over construction delays at a Boston-area generating plant, Public Citizen said. In that case, ISO-NE agreed to a $500,000 civil penalty that was paid for through a reduction in executive compensation. (See FERC Investigation Faults ISO-NE in Capacity Market Fraud.)

PJM's penalty was due in part to violations at the Quad Cities Nuclear Generating Station near Cordova, Ill. | *Farragutful, CC BY-SA 4.0, via Wikimedia Commons*

PJM in turn pushed back on this suggestion, pointing out that the 2008 order on cost recovery was not applicable to the ISO-NE violation, which did not concern recovery of a NERC penalty. Furthermore, PJM said, FERC did not require ISO-NE to pay its penalty from executive compensation; the ISO made that decision on its own. The RTO reiterated that its proposed recovery mechanism is valid under the 2008 order and suggested Public Citizen has a problem with the order itself, not with PJM's use of it.

FERC sided with PJM on the applicability of its 2008 order and said commissioners were "not persuaded" by the arguments of Public Citizen. The commission said that because PJM had "adequately addressed the factors identified by the guidance order," it would grant the RTO's request for cost recovery, effective Aug. 30.

But commissioners' reactions to the decision were mixed, as Danly's concurrence demonstrated. While the commissioner agreed PJM had "met its relatively light burden" of proof regarding its ability to recover costs, he argued in his filing that not only does the RTO have a history of "undercutting or dismantling core market design principles essential for just and reasonable rates," the case makes clear that "PJM also is not very good at reliability."

"I would treat PJM like the public utility that it is and … investigate PJM's manifest failures to ensure or at least advocate for just and reasonable rates — and now to also investigate whether PJM is complying with existing reliability rules," Danly said. "The commission should not hesitate to enquire whether a public utility serving as [an RTO] should continue in this critical role when rates and reliability failures suggest it is not doing very well."

Danly suggested that the commission has authority to conduct such an investigation under Section 206 of the Federal Power Act. Although FERC has not taken this action on its own, Danly pointed out that "any entity with standing" could file a case, and wondered if this would "have more of an effect … than a $140,000 penalty that we pass through to ratepayers." ■

PJM News

Dominion Energy Seeks Approval for Long-duration Storage Pilot

By James Downing

Dominion Energy on Sept. 18 asked Virginia's State Corporation Commission (SCC) to approve a long-duration energy storage pilot project that it said would greatly increase the amount of time batteries can discharge power to the grid.

The utility wants to install two storage facilities at its Darbytown Power Station, a natural gas plant in Richmond. One will test zinc-hybrid batteries from Eos Energy Enterprises, and the other will test iron-air batteries developed by Form Energy that can discharge for up to 100 hours, compared to the average of just four hours for most standard lithium batteries on the market.

"We are making the grid increasingly clean in Virginia with historic investments in offshore wind and solar," Dominion Energy Virginia President Ed Baine said in a statement. "With longer-duration batteries in the mix, this project could be a transformational step forward, helping us safely discharge stored energy when it is needed most by our customers."

The SCC needs to approve the project, as does Henrico County. If approved on time, construction would start by late next year, and the two battery systems would be operational by late 2026.

Virginia's Grid Transformation and Security Act of 2018 directed the development of battery storage pilot programs. Dominion has built three already in other parts of the state and has another three under development.

The proposal comes as Dominion is working to develop the largest offshore wind project in the country and continues to expand the second-largest fleet of solar panels in the country.

The batteries are meant to help improve the integration of renewable resources and cut the need for additional generation during times of high demand. Dominion is also seeking approval of two other battery projects; if the SCC authorizes them all, it will have 28.34 MW of batteries on its system, compared to 16 MW now.

Dominion evaluated proposals from over 30 companies and picked Eos and Form because they have paths to commercial viability, as well as safety, the supply chain, efficiency and support from investors, it told the SCC.

Form's iron-air battery is a 4.94-MW/494-MWh AC multiday system, while Eos' zinc-hybrid is 4 MW/16 MWh.

"These technologies are expected to have lower thermal runaway risks than lithium-ion energy storage currently presents," Dominion said in its application. "Additionally, recent history has shown significant pricing volatility and supply chain constraints for lithium-ion battery materials that could cause limits to the energy storage buildout plans."

Competition for the raw materials for lithium-ion batteries with the vehicle market is getting increasingly fierce, which will significantly increase price volatility. The grid is also going to need long-duration energy storage to help balance the growing share of intermittent resources, Dominion said.

The Form system is made up of 128 37-foot containers, while Eos' is made up of 39 17-foot containers. The two facilities will also require about 10 inverters and two transformers. Despite covering a total of 435,600 square feet, Dominion said the project will be largely hidden from neighbors on the existing plant's site, so it does not present any environmental justice issues.

Form's battery is made of iron, water and air. It works by using "reversible rusting": While discharging it takes in oxygen from the air and converts metal iron to rust, and while charging, the application of an electrical current converts the rust back to iron, and oxygen is released.

"We are pleased to partner with Dominion Energy on the innovative Darbytown Storage Pilot Project and look forward to delivering a 100-hour iron-air battery system that will enhance grid reliability and provide Dominion's Virginia customers with access to wind and solar energy when and where it is needed over periods of multiple days," Form CEO Mateo Jaramillo said.

Eos' system can operate in three- to 12-hour discharge configurations. During charge and discharge, ions move through electrolytes to their respective electrodes to donate or accept electrons, creating a current flow through the battery's bipolar stack.

"We are proud to have been selected for this critical project. Dominion understands that meeting our future energy needs requires multiple storage technologies," Eos CEO Joe Mastrangelo said. "We're excited to show Dominion how well our zinc-hybrid batteries perform."

Dominion is asking to spend about $70.6 million on the project. That works out to $7,897/kW, which is a premium compared to the $1,325/kW standard batteries cost, according to U.S. Energy Information Administration data used in its 2022 Annual Energy Outlook, the agency's most recent. ■

| *Eos Energy Enterprises*

PJM Members Lobby Board Ahead of Expected CIFP Filing

Letter Outlines Seasonal Risk, Complexity And Other Concerns

By Devin Leith-Yessian

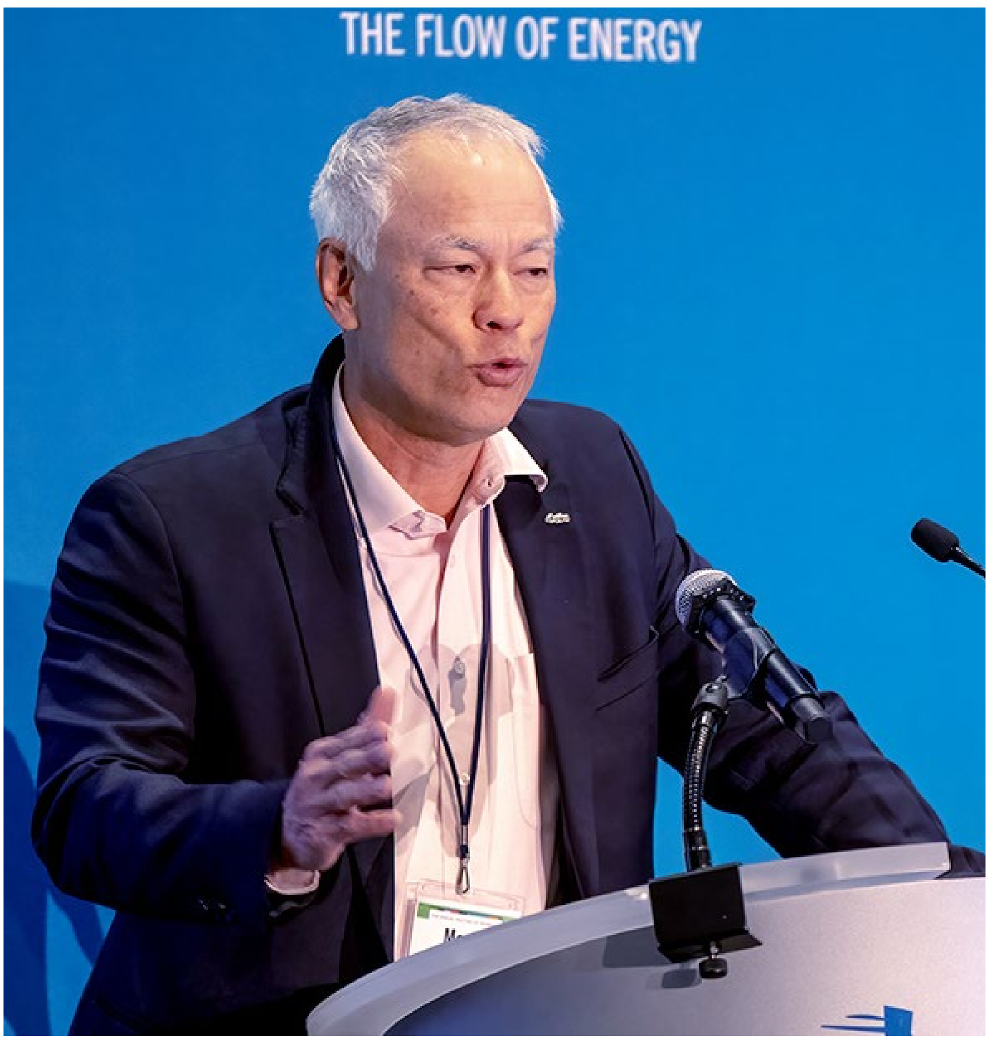
PJM members of all sectors have written letters to PJM's Board of Managers urging that it direct PJM to file disparate changes to the capacity market in the wake of the critical issue fast path process (CIFP) that concluded in August with no proposals carrying the sector-weighted support of the membership.

American Municipal Power (AMP) called on the board to direct a narrower filing focused on reworking the nonperformance penalty rate generators pay should their units not meet their obligations during an emergency, as well as the corresponding annual stop loss limit, to be based on the Base Residual Auction (BRA) clearing price rather than the net cost of new entry (CONE).

AMP noted that although none of the CIFP proposals received sector-weighted support in August, the only proposal to receive a bare majority of support consisted of the changes to the nonperformance penalties. Shifting to penalties based on auction clearing prices also was endorsed by the MC in May, but was not included in a subsequent filing revising the capacity performance (CP) construct. (See *FERC Approves PJM Change to Emergency Triggers*.)

AMP said the August vote also showed considerable support for deeper changes to PJM's capacity market, but also hesitation about making major changes with little time to conduct analysis and simulations to determine the potential effects.

"Many of the reforms discussed during the last five months still require more time for developing details and analyzing impacts. As AMP communicated early in the CIFP-RA process, the October 1 deadline is arbitrary and was an unnecessary impediment to developing a fully implementable set of reforms with broader support. Had more time been allotted the CIFP-RA process, stakeholders would have had adequate time to more fully understand the elements of each proposal and express their informed preferences," the AMP letter said.



PJM Board of Managers Chair Mark Takahashi | © *RTO Insider LLC*

A broader consortium of power co-ops and industrial customers recommended a limited filing, followed by continued discussions with stakeholders on how to make changes to the core of the capacity market.

"The implications of those changes must be thoroughly evaluated in order for market participants, other stakeholders and this coalition in particular to understand the financial impacts on suppliers, load-serving entities and consumers. Implementation of reforms will require several capacity auctions in quick succession, and implementing these changes without fully considering their impact risks irreparable harm, and equally hasty and non-comprehensive follow-on mitigation efforts. Accordingly, additional time for consideration of all proposals is needed to ensure fair outcomes for everyone," the letter said.

The PJM Industrial Customer Coalition (ICC) supported PJM's proposal to increase modeling of winter risk, so long as the RTO continues to capture the reliability risks faced during the summer and the potential for electrification to exacerbate those risks. The ICC also supports the proposed expanded weather history, seasonal capacity testing requirements, adopting CP penalties and a stop-loss based on capacity prices, and requiring that generators report whether their fuel procurement contracts include firm service and potentially incorporating that into their accreditation.

Shell Energy North America argued the fast timeline for the CIFP process prevented a holistic and durable proposal from emerging and the discussion of market changes did not include full understanding of the barriers to investment in the capacity market. It stated that the forward markets have lost a significant amount of liquidity and seen a rise in the amount of risk investors take on. PJM's proposed accreditation changes, new

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qualification standards for capacity resources and performance requirements would further increase market uncertainty, exacerbated by existing "regulatory uncertainty, administrative complexity and rule intervention."

The Shell letter stated that many of the CIFP proposals would increase the administrative complexity of the capacity market and argued that future discussions should include the energy and ancillary service markets with the goal of increasing revenues from those markets to reduce reliance on the capacity market for maintaining reliability.

"Reliance on capacity markets as the primary mechanism for ensuring resource adequacy should be reduced over time as PJM transitions to a system with more intermittency. Energy and ancillary service market design enhancements can be administratively simple and transparent enough to effectively create market signals needed to address the unprecedented system changes and concomitant needs," the letter said.

Several generators, including LS Power, J-Power and Talen Energy, submitted a letter recommending a "surgical filing" in October that includes portions of PJM's proposal, while leaving the bulk of the capacity market intact. The recommended changes include shifting the reliability metric to expected unserved energy, a more granular hourly modeling in the reserve requirement study (RRS), seasonal capacity testing requirements, using weather history data going back to 1993 and more explicitly modeling the relationship between load patterns and weather in the RRS, fuel procurement contract reporting, and shifting the CP penalties to be based on the BRA clearing price with a corresponding market seller offer cap that reflects all capacity market risks.

The generators also recommend PJM continue to work with stakeholders to overhaul the capacity market in a way that improves transparency and replicability of market components, provides confidence that any changes will function as intended and has visibility into market risks and opportunities.

A letter from Talen Energy Marketing focused on how nonperformance penalties affected resources with long lead start times, arguing that not including an excusal for those generators unduly penalized them for operating according to the parameters included in their capacity offer.

"Shifting responsibility with respect to knowledge of the grid needs, including commitment and dispatch decisions, to generators by penalizing them during long start times, even if PJM dispatches them late or not at all, is untenable. It introduces risk that cannot be mitigated and likely will lead to the retirement of the very resources that are critical for reliability today and necessary for a reliable transition to a cleaner future," Talen wrote to the board.

The East Kentucky Power Cooperative (EKPC) also encouraged a limited approach for any filing made in the near term, encouraging the board to revise the nonperformance penalty rate and to have resources dispatched consistent with their physical and fuel constraints. In the long term, EKPC recommended that the board direct staff to continue engaging with stakeholders to work toward a capacity model with hourly commitment.

Several environmental organizations and consumer advocates argued the cost implications the CIFP proposals would have for consumers was not adequately understood throughout the process and any filing should contain rules to protect against seller market power. It stated that PJM's proposal includes a capacity performance quantified risk (CPQR) formula that would not include energy and ancillary service revenues, which it said would increase capacity costs without increasing reliability, would weaken the IMM's ability to review capacity offers and would dilute the cost benefits of a seasonal capacity market with the design of the proposed demand curves.

The letter also said PJM's proposal would not accurately reflect seasonal risk by not capturing the trend of increasing temperatures resulting from climate change and would zero out the capacity benefit of ties value by relying on a "binary, unrealistic and untested assumption" that no outside capacity will be available during critical hours.

The Organization of PJM States Inc. (OPSI) submitted a letter stating the majority of member states support PJM's proposed changes to reliability risk modeling and increasing testing requirements for generators, which they believe would improve the ability to ensure generators that rarely are dispatched would be operational for future events such as the December 2022 winter storm.

The variability that led PJM to back away from a longer 50-year historical weather lookback displayed the sensitivity of PJM's modeling, leading OPSI to recommend PJM justify its approach annually and develop a plan to use appropriate data selection going forward. The states opposed PJM's proposal to retain the exemption that intermittent, storage and hybrid resources have from the requirement that generators enter the capacity market, which OPSI said raises market power concerns. Instead, the organization recommended that a future capacity market design align with all resources' operating characteristics and require that all generation participate.

"Allowing certain exempt resources to retain Capacity Interconnection Rights will not allocate and properly ration costly and scarce transmission access rights to resources relied upon by customers to ensure reliability," OPSI said.

American Electric Power, Dominion and Duke Energy Kentucky submitted a letter calling for a transitionary period for fixed resource requirement (FRR) entities to adjust to any new market design, arguing the potential for the changes to be effective for the 2025/26 BRA — scheduled for June 2024 — leaves them with little time to coordinate with state commissions and make necessary changes to their integrated resource plans or generation fleets.

The utilities requested the board include an expanded FRR transition mechanism of at least four delivery years and an off-ramp for new FRR entities for the first five years after they elect to go that route, maintain the physical penalty option for CP penalties and expand it to be applicable to all RPM capacity resources, and maintain the ability to net performance during a performance assessment interval. The letter also argues that any proposal should include recognition of the impact accreditation changes could have on state resource planning.

PJM's proposed changes to resource accreditation were particularly worrisome to the utilities, which stated they could face a reduction in the rating of their resources amounting to as much as 30% with less than a year to make up for the lost capacity. Paired with PJM's proposed changes to the penalties FRR entities could face if they fail to procure adequate capacity or do not perform during an emergency, the letter states FRR entities could face "unjust and excessive penalties" if they're not provided with time to adjust to market changes.

"These changes, combined with the expedited nature of the CIFP-RA process, make it very difficult for FRR entities to understand what their underlying positions and obligations will be under the new construct, thus creating greater uncertainty and introducing additional risk," the letter said. ■

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Stakeholders Approve Generation Deactivation Issue Charge

VALLEY FORGE, Pa. — The Markets and Reliability Committee voted Wednesday to approved a joint PJM and Independent Market Monitor *issue charge* to create a new senior task force charged with exploring changes to the timeline in which generators must notify PJM of their intent to retire a resource and how compensation is determined under reliability-must-run (RMR) contracts.

The issue charge passed with 67% support over a competing *issue charge* proposed by Vistra, which would have tackled the same core topics, but with additional language intended to make the in and out of scope components more explicit. Vistra's Erik Heinle said the company's language was built off the PJM/IMM proposal and also would have sought to ensure minimal disruption to the markets when an RMR is implemented, provided better balance by taking the need for operator flexibility into account, added education items — including around the reliability backstop — and tightened the focus of when an RMR contract should be considered.

Presenting the *problem statement* and issue charge, PJM's Chris Pilong said there is a concern the increasing pace of generation retirements expected over the next decade will increase the need for RMR contracts. He said the process of reaching an agreement with generators is not standardized and takes considerable time, prompting a desire to get more lead time from resources ahead of their desired deactivation date and to streamline the process.

The committee deferred voting on the proposal during its August meeting as stakeholders continued fine-tuning the scope. (See "Stakeholders Defer Vote on Generation Deactivation Issue Charge," *PJM MRC Briefs: Aug. 24, 2023*.)

While Pilong said PJM didn't have any deal-breaking objections to Vistra's language, he felt the core of what Vistra was seeking already had been captured in PJM's issue charge and the additional language around the scope of the discussion was unnecessary and raised procedural issues around how detailed issue charges should be.

Constellation Energy's Adrien Ford | © *RTO Insider LLC*

Both the PJM/IMM and Vistra issue charges originally would have precluded any solutions that included changes to market rules. However, several stakeholders argued the existing rules do not adequately define how resources operating under an RMR contract fit into the energy and capacity resource stacks and interact with the clearing price. The revised issue charges drafted during the meeting were both modified to include the supply stack and clearing price as being in scope. The Vistra proposal also saw added language about minimizing impacts to consumers added during the meeting.

Pilong said PJM's intention was that interactions with the supply stack and clearing price would be an educational item and if stakeholders determined that market changes are necessary, that could be referred to another stakeholder group.

Constellation's Adrien Ford said she believed the resource stack would be considered in scope and having it be to the contrary would cause her to second-guess her support for the issue charge. She said the use of RMR contracts is a consequence of market failures and she would not be comfortable with altering RMR rules without considering corresponding changes to related market rules.

Independent Market Monitor Joseph Bowring said he was happy to see stakeholders interested in addressing how RMR resources fit into the supply stack but cautioned against making the issue charge too broad.

"You can't solve every problem in every issue charge," he said. "… Let's start a parallel one and get started on it immediately."

Following stakeholder feedback during the first read of the issue charge, the PJM/IMM issue charge was revised to remove a third in scope focus for the new task force to address additional triggers for a retiring resource to qualify for an RMR contract beyond transmission constraints, with the given example of preserving ample supply of black start resources in a region.

Consumer advocates said the scope of the discussion should be balanced with the need to move quickly to shore up issues with the RMR process before an uptick in retirements manifests.

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Susan Bruce, representing the PJM Industrial Customer Coalition (ICC), said it makes sense that if the compensation for RMR resources is open for discussion, the impact on the energy and capacity markets also should be part of the solutions on the table.

"Customers that are having to pay for an RMR want to make sure they're getting the benefit they're paying for. So I want to make sure we're not foreclosing on options available in the future," she said.

PJM Issue Charge on Reserve Certainty Approved

Stakeholders approved an expansive *issue charge* that aims to rework several areas of PJM's reserve markets. The PJM proposal received 59% support over a second *issue charge* proposed by the Market Monitor, which would have focused the scope solely on addressing the decline in synchronized reserves response rate since a market overhaul was implemented in October 2022. (See "PJM Provides First Read on Reserve Certainty Issue Charge," *PJM MRC Briefs: Aug. 24, 2023*.)

The document lays out a phased process for addressing six core issues over 12 to 18 months under a new senior task force. Resource performance and penalties, aligning the offer structure with fuel procurement and reserve deployment would begin immediately with the goal of completing in six to nine months. The task force would work concurrently on procuring a quantity of reserves that reflects system needs, with the goal of arriving at a solution in nine to 18 months.

Once the most immediate needs have been addressed, the remainder of the timeline has the task force moving on to the reserve product participation requirements and incentivizing resource flexibility.

PJM's Donnie Bielak said the issue charge was revised since its first read to add education, particularly around how technology could be used to improve existing practices.

Brock Ondayko of AEP Energy questioned if there's an opportunity to discuss PJM's practice of holding resources to a 10-minute response time expectation, rather than the 15-minute mandate under NERC's Disturbance Control Standard (DCS). Bielak said PJM would consider that a change to PJM's compliance with reliability standards and therefore out of scope.

Bruce said the scope of the issue charge could cause it to overlap with ongoing work in other stakeholder groups and she questioned whether there is potential for a "feedback loop" where multiple groups take actions to increase reserve response or procurement and overcorrect.

PJM's Becky Carroll said staff have worked with the Electric Gas Coordination Senior Task Force (EGCSTF) when shaping the issue charge and which components should fall under that group and the new task force.

Deputy Market Monitor Catherine Tyler said the PJM issue charge seeks to roll three different issues under the umbrella of a single issue charge: the synchronized reserve response rate, market issues highlighted during the December 2022 winter storm and maintaining adequacy reserves throughout the clean energy transition. She argued that the EGCSTF already is at work on issues related to Winter Storm Elliott and topics related to the transition and renewable resources would fall best under a separate issue charge.

By having all the issues PJM seeks to address under one issue charge, she said it's likely any solution would focus on increasing reserve procurement at the expense of other possibilities, including changes to dispatch, market timing and unit commitment.

Ford said the Market Monitor's language wouldn't include discussion of compensation, which she believes needs to be available as part of a solution.

Gregory Poulos, executive director of the Consumer Advocates of the PJM States, said state advocates preferred the Market Monitor's proposal for being more narrowly focused on response rates, which he said is a clearly documented issue, whereas the other topics in PJM's proposal have more moving parts and interactions with issues before FERC.

Jurisdictional Questions Raised Around Co-located Load Proposal

Stakeholders discussed a *proposal* that would create new rules for wholesale generators with co-located loads without supply from the system. The package, which was sponsored by Exelon in the Market Implementation Committee, was the only one of several proposals to pass, receiving 51% of the vote in August. (See "Stakeholders Endorse Proposal on Co-located Load," *PJM MIC Briefs: Aug. 9, 2023*.)

Generators would be permitted to retain their capacity interconnection rights (CIRs) equal the amount of energy supplied to co-located loads under the proposal and would be treated as a load serving entity (LSE) responsible for service charges and retail delivery costs. Current PJM rules require that generators relinquish a portion of their CIRs equal to co-located load they are serving under these configurations.

Several amendments were offered to the proposal, which largely were opposed by Constellation, with the exception of removing outdated language around cost-based offers. The amendments would remove the requirement that the load be capable of curtailing within 10 minutes on the basis that treating the generator as an LSE means the configuration would have its own metering and would be part of PJM's load forecast. Any member can block amendments to the MRC's main motion.

Exelon's Sharon Midgley suggested the amendments could be considered as an alternate package.

Ford urged the committee to vote against the proposal, saying it would violate the Federal Powers Act (FPA) by treating load that isn't receiving power from the PJM grid as being FERC jurisdictional. Constellation, joined by Brookfield Renewable, was one of several companies to offer proposals during the Market Implementation Committee's discussion of the subject.

"It's in the title. This is a not grid-connected package," she said.

Midgley said the Exelon-sponsored and MIC-endorsed proposal considers the co-located load as end use and retail load, in line with Constellation's definition. The MIC-endorsed proposal also allows the generator to offer the entirety of its resource into the PJM capacity market, which accommodates one of the key interests as expressed by Constellation and Brookfield.

Economist Roy Shanker said he believes the proposal would run into jurisdictional issues at FERC and it could set a bad precedent of states ceding jurisdiction over retail loads.

"This sets the stage for a real legal mess. The load being discussed here simply is not FERC jurisdictional load," he said.

First Read of 2023 RRS Values

PJM's Andrew Gledhill gave a first read of its *recommended values* for the 2023 Reserve Requirement Study (RRS), which calls for an uptick in its capacity procurement targets.

The installed reserve margin (IRM), which sets the targeted capacity level above expect-

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ed loads, would rise from 14.7% for the 2026/27 delivery year (DY) in the 2022 study to 17.6% for the 2027/28 DY. The forecast pool requirement (FPR), which considers forced outage rates, also would increase from 9.18% to 11.65% for the corresponding DYs. (See *PJM Presents Preliminary 2023 Reserve Requirement Study to Stakeholders*.)

The study continues to base its results on the PRISM software PJM long has used to conduct its reliability modeling, rather than using the hourly model developed from its Effective Load Carrying Capability (ELCC) accreditation studies. PJM ran both sets of modeling for this year's study and plans to phase over to just using the hourly approach in future studies. The hourly results would have resulted in higher IRM and FPR values.

Gledhill said this year's study used a more granular hourly approach for its load modeling, separate from the ELCC model, which yielded a more comprehensive look at load uncertainty. Based on that data, PJM believes it has been under-forecasting summer load uncertainty.

James Wilson, a consultant for several state consumer advocates, said he has not heard concerns expressed about summer resource adequacy and questioned why PJM proposes to raise summer requirements by over 3 GW of additional capacity. He encouraged stakeholders to vote against the RRS values.

In addition to setting an initial IRM and FPR value for the 2027/28 DY, the study resets the figures for the previous three years. The preliminary results would be increased by a similar margin for each of those years.

Minimal coincidence between the PJM peak load period and the "world" peak — which is defined as MISO, NYISO, TVA and VACAR — led to the capacity benefit of ties (CBOT) value more than doubling to 2.2% from the 1% value in the 2022 study. To reduce volatility, PJM elected to average the CBOT values from 2017-22 and use that figure, which landed at 1.5%, instead.

Fifth CONE Area Under Consideration

Stakeholders discussed a proposal to create a fifth cost of new entry (CONE) area for the Commonwealth Edison (ComEd) region in Illinois. The gross CONE in the new area would be $201,714/MW-year, while CONE Area 3, which ComEd is currently under, is $197,800/MW-year. (See "Competing Proposals Addressing Local Factors on Net CONE Merged," *PJM MIC Briefs: Sept 6, 2023*.)

The change is the result of a process exploring how to account for local or state factors that could impact cost to build the reference resource in a specific region. PJM's Gary Helm said the primary reason for calculating a separate CONE value for resources in the ComEd region is the requirement that generators be emissions free by 2045 under the state's Climate and Equitable Jobs Act (CEJA).

"There is debate over whether that can or cannot be achieved, but in this case for all intents and purposes we would reflect that all natural gas resources, which is the reference resource, would have a reduced asset life," Helm said.

The proposal would calculate a new CONE value for the new area by effectively applying an asset life factor with the assumption that the reference resource, currently a combined cycle resource, would retire in 2045. All other variables would stay the same at this time but could be changed during the next quadrennial review.

J-Power USA introduced a package to implement an automated process for the creation of new CONE areas in the future. That proposal was dropped when it concurred with PJM that the existing stakeholder process is sufficient.

Clara Summers of the Illinois Citizens Utility Board (CUB) said the proposal is very specific to Illinois and could set a precedent that other state consumer advocates should note.

Proposed Changes to Load Forecast Adjustment Timeline Discussed

The MRC reviewed *proposed* revisions to Manual 19 that would change the data PJM requests when electric distribution companies (EDCs) or LSEs submit load forecast adjustments. The new language would request hourly data as well as a 15-year forecast with a public document detailing how the forecast was created and move up the Load Analysis Subcommittee's review of forecast adjustment requests to initiate in September and October. (See "PJM Presents Quick Fix on Load Forecast Guidelines," *PJM PC/TEAC Briefs: Sept. 5, 2023*.)

The proposal is focused on providing PJM with more insight into data center load growth. In past MRC meetings, PJM's Mary Mooney said data centers often can be built faster than other large loads, meaning there's less time to plan and build needed grid adjustments, and the load often is not captured in the existing forecasting structure that is based on projected labor data.

Mooney said PJM would avoid double-counting load already captured in the forecasting it does based on economic data, but she does not anticipate this to be a major concern as data centers have outsized electric needs compared to their employment figures.

Wilson argued the proposal should require that a load adjustment be in the footprint of the relevant EDC. He also recommended PJM hire an independent consultant to do a study and forecast of long-term data center load, rather than rely on information provided by EDCs.

Members Committee

Nominating Committee

The Members Committee elected a new slate of sector nominees for the 2023-24 Nominating Committee during Wednesday's meeting. The representatives will be as follows:

- Electric Distributors: Bill Pezalla of the Old Dominion Electric Cooperative (ODEC);
- End Use Customers: Susan Bruce of the PJM ICC;
- Generation Owners: Marji Philips of Rolling Hills Generating;
- Other Suppliers: Sean Chang of Shell Energy North America; and
- Transmission Owners: Laura Yovanovich of PPL Utilities.

PJM Revises Code of Conduct to Promote Civil Discourse

PJM General Counsel Chris O'Hara said the code of conduct staff and stakeholders are held to has been updated in the wake of incidents where personnel have been singled out and attacked during meetings. The changes reflect expectations during stakeholder meetings and how PJM will respond to future incidents.

"These personal attacks are completely inappropriate. Personnel presenting on PJM's behalf have the full backing of the PJM administration," he said.

PJM has a legal obligation to create a workplace that is free of discrimination for its employees, O'Hara said. The appropriate venue for stakeholders to comment on PJM staff performance is the Liaison Committee.

Members Committee Chair David "Scarp" Scarpignato encouraged stakeholders to maintain a friendly decorum during meetings. ■

Company Briefs

First Solar Breaks Ground on 5th US Thin Film Manufacturing Plant

Solar PV manufacturer First Solar last week broke ground on a 3.5-GW fully integrated manufacturing plant in Iberia Parish, La.

The factory is First Solar's fifth in the U.S. and represents $1.1 billion in investment.

The first shipments of Series 7 modules are expected to leave the plant in the first half of 2026.

More: *Pv Tech*

Engie to Supply Microsoft Texas Centers with Renewable Program

Engie Energy Marketing last week announced it has agreed to provide renewable energy to cover the power needs of select Microsoft data centers in Texas.

The agreement will allow Microsoft to match ERCOT data center load with clean power. Engie will source the energy from its portfolio of wind, solar and battery projects in the state.

The deal is said to accelerate Microsoft's mission to transition to 100% carbon-free energy by 2030.

More: *Solar Industry Magazine*

Federal Briefs

Air Force Breaks Ground on First Electric Aircraft Charging Station

AFWERX, along with electric aerospace company BETA Technologies, broke ground last week on the first electric aircraft charging station on a military installation at the Air Force's Duke Field in Florida.

The Level 3 direct current electric vehicle fast charging station is expected to be completed by Oct. 13, weeks before BETA's electric vertical take-off and landing (eVTOL) aircraft arrives for testing.

To provide enough power to the 480-volt, 400-amp charging station, the base had to upgrade its grid and purchase a 1000-kW volt-amp transformer.

More: *Dayton Daily News*

EPA Announces $4.6B in Pollution Reduction Grants

EPA announced last week the launching of a $4.6 billion competition to fund state, local and tribal programs to cut pollution, advance environmental justice and deploy clean energy solutions across the Pacific Northwest.

EPA also announced the awarding of 28 grants totaling nearly $20 million to support climate planning efforts in the region.

Awarded states included Alaska, Idaho, Oregon and Washington.

More: *EPA*

DOE Announces $325M for Long-duration Storage Projects

The Department of Energy last week announced that it has selected nine proposals for long-duration energy storage test projects to receive $325 million in funding.

The funds, mostly allocated by the Bipartisan Infrastructure Law, will go to projects that can deliver stored electricity for a period of 10 hours or more.

After DOE's $325 million, private capital will supply the remainder of an expected $800 million to build the projects.

More: *Canary Media*

State Briefs

COLORADO

EPA Approval of Denver Smog-reduction Plan Partially Tossed

The 10th U.S. Circuit Court of Appeals last week voted 2-1 to partially invalidate EPA's approval of the state's plan to reduce smog near Denver after an environmental group complained it allowed "unlimited" pollution from fracking.

The court agreed with the Center for Biological Diversity that EPA broke the law when it approved a state permitting plan for smog reduction that excluded emissions from temporary pollution sources, including fracking. However, the court did not invalidate other elements of the plan, which aims to reduce emissions from major new or modified stationary sources of air pollution.

Judge **Nancy Moritz**, writing for the majority, said "EPA acted contrary to the law in allowing Colorado to exclude all temporary emissions under its permit program" since federal regulations do not allow such an exclusion.

More: *Reuters*

Xcel Proposes $15B in New Renewable Generation

Xcel Energy last week filed a clean energy plan with the Public Utilities Commission, outlining 22 renewable projects that will cost an estimated $15 billion.

The projects would add 6,545 MW of renewable energy, including 1,170 MW of battery storage and 628 MW of natural gas plant capacity. The projects would be built between 2026 and 2029.

Xcel said $10 billion in federal tax benefits, most part of the Inflation Reduction Act, will cover the cost of construction.

More: *Seeking Alpha*

ILLINOIS

Supreme Court Suspends Law Licenses of Pramaggiore, McClain

The Illinois Supreme Court last week suspended the law licenses of Anne Pramaggiore and Mike McClain on an interim basis following their convictions on federal charges of bribery, bribery conspiracy and willful falsification of records.

Prosecutors alleged Pramaggiore, the former CEO of Commonwealth Edison, and McClain, a lobbyist for the utility, conspired with others to influence former House Speaker Michael Madigan to pass certain legislation. McClain and Pramaggiore are scheduled to be sentenced in January.

More: *Reuters*

KENTUCKY

PSC Approves Pike Co. Crypto Mining Operation for Discounts

The Public Service Commission last week approved more than $2.5 million in electricity discounts over several years from Kentucky Power to a cryptocurrency mining operation in Pike County.

As part of the approval, the PSC is requiring that Kentucky Power follow several conditions to make sure the costs of the discounts given to Cyber Innovations Group don't harm ratepayers, who already pay the highest bills in the state. In exchange for the discount, Cyber Innovations Group will invest $3.5 million in its facility.

Kentucky Power said it would purchase available electricity from PJM to meet the mining operation's power demands.

More: *Kentucky Lantern*

MINNESOTA

PUC Approves Land Acquisition for Xcel Solar Project

The PUC last week unanimously approved Xcel Energy's acquisition of land rights for the Sherco 3 solar plant that will complement the Sherco 1 and 2 projects in Becker.

Sherco Solar 1 and 2 — a two-phase project approved by the PUC last year — cost $690 million and will generate up to 460 MW. Sherco 3 will have a capacity of 250 MW.

Sherco 3, which is expected to cost $409 million, still must get a permit from the PUC. Xcel plans to complete the entire Sherco complex by the end of 2025.

More: *Star Tribune*

MISSOURI

Evergy Withdraws Request to Make Time-of-use Pricing Optional

Evergy last week withdrew a request from the Public Service Commission to make its upcoming time-of-use pricing plan optional.

Under an order from the PSC, Evergy is expected to implement time-of-use pricing, which places a premium on electricity prices at times of high demand. Citing blowback from the public and elected officials, the company later requested that the PSC allow the program to be optional. However, in a pleading filed last week, the utility withdrew its request, citing concerns from the Office of the Public Counsel and others.

More: *Missouri Independent*

NEVADA

NV Energy: Greenlink Project About 11 Months Behind Schedule

NV Energy's Greenlink Nevada Project, which will add two transmission lines to improve grid infrastructure, is currently 11 months behind schedule, according to Carolyn Barbash, the company's vice president of transmission development and policy.

Barbash cited the general permitting and routing processes for the delay.

The new line between Las Vegas and Yerrington is planned to be in service by 2027. The line between Yerrington and Ely would be in service in 2028.

More: *KTNV*

NEW MEXICO

PRC Approves Rate Credits for PNM Customers

The Public Regulation Commission last week approved a settlement between various parties and the Public Service Company of New Mexico that sets rate credits for customers going forward.

Under the agreement, PNM will provide a total of $115 million in rate credits. The credits will be dispersed over the course of one year and, during that time, the average residential customer will see a $9.28 (11%) credit on their bill.

The PRC previously ordered PNM to issue credits, but the utility appealed the order to the state Supreme Court in June 2022. The court remanded the case to the PRC last week after PNM reached an agreement with the other parties involved.

More: *NM Political Report*

VIRGINIA

Dominion Offers Virginia Beach $19M for OSW Tx Easements

Dominion Energy last week offered to pay Virginia Beach $19 million for roughly 4 miles of city easements to transmit energy from its Coastal Virginia Offshore Wind farm.

Dominion has also agreed to provide $1.14 million to replace trees that will be razed to make room for the lines and poles. The route was chosen after Dominion collected public feedback in 2021. It was approved by the State Corporation Commission in 2022.

Construction of the 176 turbines is scheduled to begin next year.

More: *The Virginian-Pilot*

Halifax County Recommends Permit Denial for Solar Farm

The Halifax County Planning Commission last week voted 5-2 to recommend the denial of a conditional use permit for a 102-MW solar project.

The county board of supervisors in 2020 adopted a Scenic River designation for the Staunton River, which will be 300 feet from the project, leading commissioners to deem the location "not a good fit."

The board of supervisors, which has the final say on the project, may vote at its meeting in October.

More: *SoVaNow.com*