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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

PJM

Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC (p.26)

SPP CAISO/West

SPP's Experience with Seams Could Help Markets+ (p.36)

Pathways Participants See 'Pivotal' Chance to Build New Kind of RTO (p.9)

ISO-NE

FERC Approves New Pathway for New England Transmission Projects (p.14)

PJM

PJM Hears Proposals to Redesign EE Participation in Capacity Market (p.28)

NYISO

MISO: Sloped Curve Would Have Raised 2024/25 Capacity Auction Prices (p.18)

MISO Monitor Spotlights Congestion Fixes, Market Mismatches in 2023 (p.19)

MISO Proposes to Split LMR Participation, Accreditation into Fast/Slow Groups (p.20)

COVER: Talen Energy's Susquehanna Nuclear Power Station *(Page 26)* | *Jakec, CC BY-SA 4.0, via Wikimedia Commons*

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In this week's issue

Counterflow

By Steve Huntoon

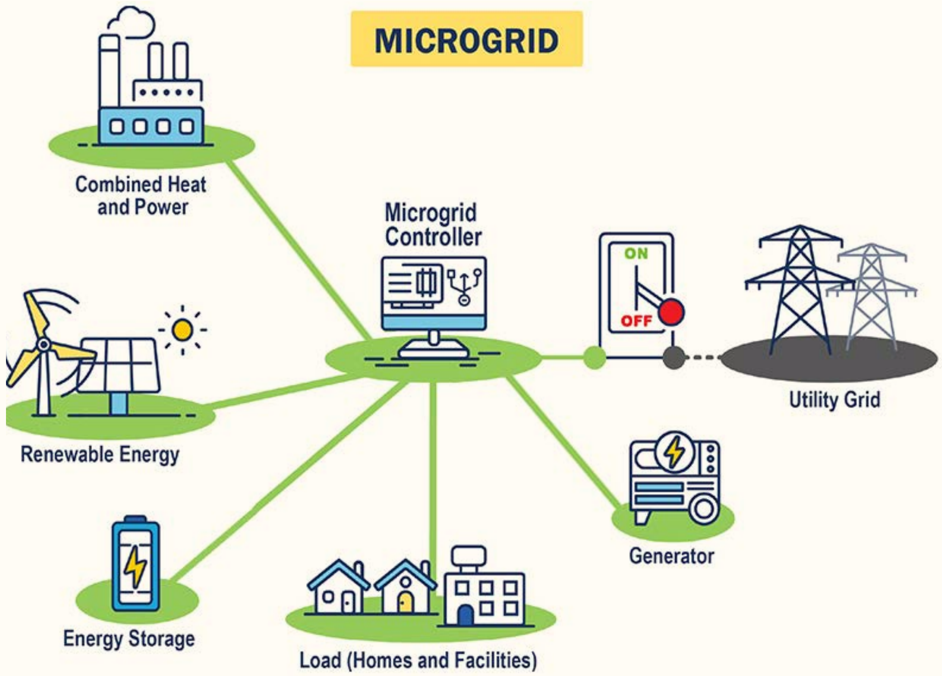
Microgrid Poster Child

By Steve Huntoon

Steve Huntoon

Every few years I return to the subject of microgrids — just to beseech everyone to please stop the insanity.

A case in point is the recent hoopla over the completion of the Bronzeville microgrid in Chicago with the usual cheerleading by proud politicians, utility officials, public interest group representatives and media publicists, with nary a Cassandra in sight.



| DOE

Cutting to the Chase

I have explained theory before, so let me cut to practice. This microgrid cost $30 million in order to provide 6,050 kW of backup generation to the Bronzeville neighborhood in the event of a widespread system outage in Chicago. That is $4,960/kW.

A typical Generac home generator provides 26 kW at an installed cost of $10,500. That is $404/kW.

Yes, you read that right. This microgrid is 12 times more expensive per kilowatt than a bunch of Generac home generators providing equivalent backup service. Yikes.

A Green Justification?

Nope. The microgrid's generation is 750 kW of solar panels, 500 kW of four-hour batteries and 4,800 kW of natural gas-fired generators.

Cost-benefit Analysis

Power outages average 43 minutes per year in Bronzeville (see page 66), i.e., reliability is 99.99%. A value of lost load analysis showed that the benefit of eliminating these outages (assuming the microgrid would do that) aggregates to about $100,000 per year (again, see page 66).

The microgrid costs $5,300,000 per year (see Page 63). So, the cost of the microgrid is about 50 times the benefit value of the microgrid. Yikes.

Cost per Customer

The microgrid costs a staggering $388 per customer served per month (see page 55), four times the average customer's monthly electric bill of $93. Of course, the microgrid is paid for with Other People's Money (other Commonwealth Edison customers), but the key point is that if this microgrid were replicated across the ComEd system, then everyone's monthly bill would go up about 500%. Yikes.

Critical Service Protection

It's been highlighted by ComEd and others that the Chicago Police Department's headquarters is within the microgrid service area — but the police HQ already had backup generation (see Page 66), as of course it should. Yikes.

OK, I'll stop the microgrid rant.

P.S. An update to my fusion column: The gigantic European ITER project announced that "energy-producing fusion reactions — the goal of the project — won't come until 2039, and only in short bursts," and that "fusion cannot arrive in time to solve the problems our planet faces today."

Here's a reminder that we could start cooling the planet tomorrow with some sand in the stratosphere. Just sayin'.

P.P.S. On the happy talk front through troubled times, this is the 50th anniversary of the writing of "(What's So Funny 'Bout) Peace, Love and Understanding" by Nick Lowe, the 45th anniversary of Elvis Costello's great cover and the 20th anniversary of the superstar cover here. If you made it to the end of this column, thank you, and please turn it up to 11. ■

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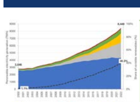

IRENA Says World Needs to Build Renewables Faster

NetZero Insider

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FERC/Federal News

Startups: Market Will Move New Cleantech Regardless of Election Outcome

USEA Briefing Focused on Emerging Technologies

By K Kaufmann

The U.S. Energy Association had billed its July 10 virtual briefing as a look at emerging technologies in the energy space, with a panel of industry executives talking about grid-enhancing technologies, nuclear fusion, small modular reactors, long-duration storage and low-carbon natural gas plants.

But questions from energy reporters at the event quickly shifted the focus to topics of the moment: rising energy demand from data centers and what happens to U.S. energy policy if former President Donald Trump is re-elected.

Arvin Ganesan, CEO of Fourth Power, a long-duration storage startup, sees the upcoming election as a secondary consideration. "The investment moment we're in is largely derived by prevailing interest rates," he said. What is driving the market is "how the electrical system is operated, and that is through, largely, state- and utility-led investments and procurement."

The growth in demand from data centers has the potential to shift utilities' approach to their operations, he said. "The amount of load growth is, for these utilities, beyond stressful; it is a threat that they need to manage. … Utilities are conservative in general with technology deployment, but their need for new electrons is so high, some of that dynamic is changing."

Fourth Power's storage technology turns excess renewable power into high-temperature heat that can be stored in carbon blocks and provide five to 500 hours of power and could be one-tenth the cost of lithium-ion batteries, Ganesan said.

Like many in the industry, he sees the tax credits for renewable energy and storage in the Inflation Reduction Act as "fairly insulated from partisanship … given the fact that well over 50% of solar and storage installations are in 'red' districts, and the employment created by these industries span the breadth of geographies in states and in districts."

Alan Ahn, deputy director for nuclear at Third Way, a center-left think tank, similarly argued that advanced nuclear has broad support from Republicans and Democrats, pointing to the recent passage and signing of the bipartisan Accelerating Deployment of Versatile Advanced Nuclear for Clean Energy (ADVANCE) Act (*S. 870*).

The law is targeted at providing the Nuclear Regulatory Commission with new authorities to, for example, improve and accelerate the permitting of advanced and micro reactors, and study advanced manufacturing techniques to help build reactors faster and cheaper.

NET Power's 50-MW low-carbon natural gas test facility in La Porte, Texas | *NET Power*

A range of tech companies — like Google and Microsoft — are looking at SMRs to provide clean, dispatchable power to data centers, and Ahn expects "robust support for advanced nuclear regardless of whether we have a Democratic or Republican administration."

The Biden administration and Department of Energy have provided strong support for advanced SMRs, with billions in federal dollars for two demonstration projects and, more recently, an announcement of another $900 million to support well designed projects that aim to build out a pipeline of SMRs. But companies have been hesitant to move ahead with projects because of the U.S. industry's recent history of massive cost overruns and schedule delays that plagued the two new reactors now online at Plant Vogtle in Georgia. (See *DOE Announces $900M to Kick-start Small Modular Nuclear Pipeline*.)

"The issue is how can we get users to move first," Ahn said. "I think the conversation has really shifted towards, are there roles that the federal government can undertake to mitigate some of this first-of-a-kind risk?"

Possible initiatives might include "some sort of completion insurance program or cost-overrun backstop that the federal government can implement," he said.

Fusion by Mid-2030s?

Andrew Holland, CEO of the Fusion Industry Association (FIA), is equally bullish on the development of nuclear fusion, which he said could reach commercial scale by the mid-2030s or before, and similarly pointed to data center and industrial demand as drivers.

Fusion technologies — which heat hydrogen atoms to extremely high temperatures, causing them to fuse together — promise to produce massive amounts of carbon-free power, according to *FIA's website*. Because the process does not produce radioactive waste, permitting fusion plants should be simpler, Holland said, requiring only a permit to operate, rather than the permits to construct and operate required for traditional, fission plants.

Microsoft signed a contract last year for 50 MW of power from fusion startup Helion, and steelmaker Nucor also is partnering with Helion on a 500-MW fusion plant. These deals "do a good job of helping to advance the technol-

FERC/Federal News

ogy of fusion … because they show there is a de-risked pathway towards getting this energy on the grid," Holland said.

"The need to have always-on, always-available, clean, firm power for these data centers can be a really important part of our network and our capital stack as we develop into the next phase of this [technology]," he said.

Ashley Smith, chief technology and innovation officer for AES, agreed that power demand from data centers, artificial intelligence and transportation and building electrification is driving a sense of urgency among utilities to figure out "how to get more electricity onto the grid."

AES has piloted dynamic line ratings at its utilities in Indiana and Ohio, Smith said, but she defended a go-slow approach to GETs and other emerging energy technologies based on traditional utility imperatives of reliability, safety and affordability.

The company is also looking at "co-location: figuring out how we site certain large loads in areas where the grid is less constrained" and therefore decrease the time to get power online, Smith said.

'If You Build It'

Other speakers at the briefing also spoke less of politics and more about the market forces that could provide ongoing momentum for emerging technologies, such as NET Power's natural gas turbines that can capture 97% of their carbon dioxide emissions.

"Different technologies … mean a lot of different things" to people, said Akash Patel, the company's chief financial officer. "Some want to focus on the use of natural gas, which makes it reliable and cheap. Some want to focus on the capturing of all the emissions, to make it clean. So, there's a lot of overlap."

NET's potential customers include not only the tech giants "who will talk about AI till the cows come home, but also the oil and gas operators that are looking for how to reduce their Scope 3 emissions [and] how to use natural gas responsibly," he said. "So, the approach we took is, if you build it, they will come."

Investors certainly have, and they could provide another hedge against political turbulence. Oxy, Constellation Energy and Baker Hughes are the company's major investors.

NET has run a 50-MW test plant in La Porte, Texas, since 2018 and is planning a 300-MW utility-scale project to go online in late 2027 or early 2028, also in Texas.

Utility investors also have helped TS Conductor gain industry acceptance for its carbon-based advanced conductors, said Charles Bayless, a long-time utility executive and a member of the company's board. Both National Grid and NextEra Energy are supporting the company, as is Bill Gates' Breakthrough Energy Ventures.

Cleantech advanced during Trump's previous administration, despite lack of federal support, but the flood of federal dollars during the Biden administration has accelerated the market.

"It is just absolutely a fact that policy will determine how quickly these technologies get to market," said John Howes, principal at the Redland Energy Group, an industry consulting firm. "There is an absolute connection between policy and the pace at which new technologies get to market. … Nobody believes that policy changes will destroy these industries, but personally, I find it hard to believe that positive policy won't accelerate these technologies." ■

FERC/Federal News

10 Northeastern States Sign MOU on Interregional Tx Planning

NARUC Releases Report on how States Can Facilitate Interregional Transmission

By James Downing

Memorandum of Understanding

Northeast States Collaborative on Interregional Transmission (“Collaborative”)

| *Northeast States Collaborative on Interregional Transmission*

Ten East Coast states signed a *memorandum* of understanding July 9 to set up a framework to coordinate interregional transmission planning and development.

Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont will explore mutually beneficial interregional transmission to increase the flow of electricity between the ISO-NE, NYISO and PJM, as well as assessing offshore wind infrastructure needs.

The states have been working on the issues for more than a year, since they sent the U.S. Department of Energy’s Grid Deployment Office a *letter* asking for help to convene a Northeast States Collaborative on Interregional Transmission. (See *Northeast States Detail Early Efforts on Interregional Tx Collaborative*.)

Massachusetts Energy and Environmental Affairs Secretary Rebecca Tepper said her state cannot go it alone to address climate change and that interregional collaboration is a top priority of Gov. Maura Healey (D).

“Through partnerships like this collaborative, we will be able to advance more cost-effective transmission projects for the residents of the Northeast,” Tepper said in a statement.

The states agreed to work together on interregional transmission infrastructure and share information. Enhancing ties between the regions should lower prices for consumers by broadening access to the cheapest available power and bolster reliability during periods of extreme weather and system stress, they said in the MOU.

“New Jersey is not alone in experiencing increasingly frequent extreme weather events and record-breaking temperatures that threaten public health and safety,” New Jersey Gov. Phil Murphy (D) said in a statement. “We are also not alone in our response to the intensifying climate crisis, which provides crucial opportunities to leverage interregional partnerships toward improving our collective resilience and economic vitality. As the Garden State bolsters its standing as a national offshore wind hub, we will continue working tirelessly alongside our regional partners to improve grid reliability.”

The collaborative has plans to produce a strategic action plan for promoting interregional transmission projects that can cut the cost of bringing offshore wind to consumers. That plan would involve identifying barriers to such projects and how to address them.

The states intend to provide opportunities for external engagement as they develop the plan. They also want to coordinate on technical standards for offshore wind transmission equipment to ensure interoperability as projects come online in different areas at different times. The states plan to work with DOE, FERC, industry and the three grid operators.

Any decisions that come out of the collaborative will require mutual consent among the states that said they would maintain their independence. That means nothing in the deal prevents them from independently or collectively seeking support or funding, advocating for or participating in any other planning and cost allocation processes.

The six New England states and New York have a *pending application* at DOE to get some funding through the Grid Innovation Program for National Grid’s Clean Resilience Link, a 345-kV line between ISO-NE and NYISO to increase their transfer capability by 1,000 MW. The $10.5 billion GIP program offers a maximum of $1 billion for projects.

Speaking for himself, Abe Silverman of Silver-Green Energy Consulting, which has been working with the states, said in an interview that the effort helps to formalize a relationship between the states, the federal government and the ISO/RTOs to move transmission forward for offshore wind and interregional transfer capacity.

While federal efforts on interregional transmission also are important, Silverman said that often, when major interregional and even intraregional lines have actually been built, states have been behind the efforts.

“There isn’t a lot of it, and what has been built ... has often been the result of concerted state efforts,” he said. “Look at the Competitive Renewable Energy Zone lines in Texas, the Long-Range Transmission Planning Program in MISO, the New York [Public Policy Transmission Need process] and New Jersey’s State Agreement Approach; ... those were all major transmission efforts that had their genesis in state agreements.”

The states in the collaborative include only a couple led by Republican governors, and many of the quotes from senior officials on it were focused on liberal policies around offshore wind and addressing climate change, but Silverman argued that interregional transmission has bipartisan bona fides.

“I often talk about how transmission policy needs to pass the ‘Joe Manchin press release’ test, which is, this is a set of policies that

FERC/Federal News

[Sen.] Joe Manchin [I-W.Va.] would be OK promoting," Silverman said. "And you look at the benefits of interregional transmission: It's lower cost for consumers; it's better reliability — particularly in the face of extreme weather — and it's about American energy independence and dominance."

Those factors, which test well with Manchin and others leaning to the right on energy, are enough to justify the investment regardless of the climate impacts, he argued.

NARUC Weighs in on Interregional Transmission with New Study

The National Association of Regulatory Utility Commissioners on July 9 released a new *study* called Collaborative Enhancements to Unlock Interregional Transmission, which was prepared by Energy and Environmental Economics (E3).

The study highlights strategies for increasing transfer capability, which state regulators have increasingly looked toward because of rising demand and ongoing changes in supply.

"As our existing grid is forced to respond and adapt to emerging needs, regulators are increasingly interested in assessing how new interregional transmission infrastructure can drive value for customers," Kansas Corporation Commission Chair Andrew French said in a statement. "This timely report provides PUCs a straightforward assessment of existing barriers preventing robust interregional transmission planning and a suite of potential solutions for regulators and other stakeholders to consider."

Maria Robinson — director of DOE's Grid Deployment Office, which helped NARUC with the report — called interregional planning critical for providing reliable and affordable power.

"Public utility commissions need practical solutions for identifying crucial interregional transmission projects to ensure power gets from where it's generated to where it's needed most, when it's needed most," Robinson said in a statement. "We are proud to support NARUC in this effort as partnerships at the federal, state and local levels are needed to meet our shared goal of a more reliable and affordable grid in the face of aging infrastructure, extreme weather and changing energy landscape."

The study argues that the limited success on interregional lines so far can be attributed to three main issues: the lack of planning motivators, cost allocation, and planning process misalignment and analysis limits.

Regions could expand coordinated planning to identify joint needs and solutions because once the same needs are identified, they would be motivated to reconcile their differing regional planning processes, or develop new ones, to identify interregional lines, the paper says.

They could also standardize universal best practices in regional and interregional transmission solutions to ensure the best projects are identified and thoroughly analyzed, while accurately assigning costs to beneficiaries, to cut friction in interregional planning. The regions should also work to reconcile differences in modeling, tools, data inputs and benefit calculation methods, the paper says.

While projects are planned and cost allocated across multiple states, they are sited by individual state regulators who most often have the final decision on what moves forward. The paper suggests ensuring projects have non-energy benefits to ensure states that bear their physical impact also benefit, which could include jobs, revenue sharing, investment in capital projects and social programs, and economic development opportunities.

States could also use the same analysis for an interregional line's "need" and coordinate their evidentiary records to synchronize permitting timelines and standardize data collected to inform decision-making, according to the study.

"Different states may still have different priorities and may choose to include different types of benefits in what they consider, but standardizing a common set of underlying facts, models and timelines could help expedite project approvals," the paper says. ■

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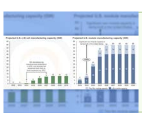

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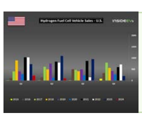

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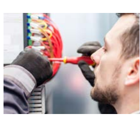

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FERC/Federal News

Report Looks at Root Causes of Electric Rate Hikes

Clean Energy Think Tank Says Renewables not to Blame

By John Cropley

A new report says residential electric rates have been rising at a pace less than inflation in most states since 2010 and that the clean energy transition is not driving the increase.

Broadly, transmission and distribution costs are rising faster than inflation, and this is a driving factor behind electric rates increasing nationwide, the report says; more narrowly, wildfires, natural gas price volatility and investments in coal plants contributed to price hikes in certain markets.

"*Clean Energy Isn't Driving Power Spikes*" was announced July 9 by *Energy Innovation Policy & Technology*, an energy and climate change think tank working to support policy designs intended to reduce emissions.

The issue of rising electric bills is real, Energy Innovation said in introducing the report, and it is a huge concern for many American families.

But clean energy, which some opponents criticize for its cost, is not to blame, the organization concludes. In fact, some of the smallest electric rate increases have been in states with high rates of wind and solar generation, such as Iowa, Kansas, Oklahoma and New Mexico.

In ERCOT, for example, the buildout of wind and solar is estimated to have reduced wholesale electricity costs by $31.5 billion between 2010 and 2022, $11 billion of that in 2022 alone.

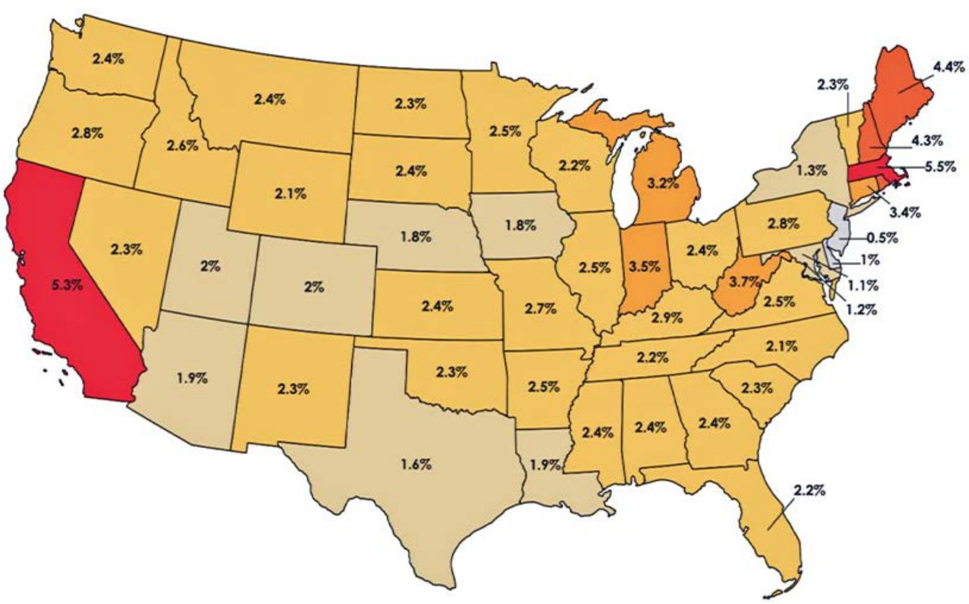
Since 2010, average residential electric rates and the U.S. Consumer Price Index both have increased about 40%, the report notes, but average bills have increased only 24%, because of reduced household energy use. Energy-efficiency measures and rising use of distributed resources such as rooftop solar are credited for this.

California, with one of the most aggressive clean energy stances of any state, has seen substantial electricity rate increases in recent years. But the report blames wildfire-related investments such as vegetation management and grid investments, which have increased to 16% of the total consumer costs for the state's three primary investor-owned utilities.

The grids in Colorado, Hawaii, Oregon and Texas also have sustained damage from major wildfires.

"As climate-related risks accelerate, the cost to electricity customers of mitigating these risks will be critical to address," the report states.

The volatile price of natural gas is identified as another contributing factor in some states, particularly Massachusetts, which drew 64% of its electricity from gas-fired generation in 2023, compared with 49% for ISO-NE as a whole.



Average annual price increases in residential electric rates | *EIA*

The report flags other factors linked by a common theme: A regulated, guaranteed rate of return incentivizes utilities to make large capital investments rather than operational investments or other options that might be more cost-effective for customers.

The report notes, for example, that utilities are continuing to invest in aging coal plants to keep them running, taking on significant new debt in the process.

The report cites data from RMI showing the average remaining plant balance increased from $560/kW of capacity to $745 from 2010 to 2020 for steam boiler power plants, a category that consists mainly of coal-fired facilities. These sunk costs (plus a regulated rate of return) are passed along to ratepayers.

Transmission and distribution costs are increasing at nearly double the rate of inflation, the report says, because of utility investment in hardening and resilience. It suggests costs could be limited by maximizing the existing grid's potential with grid-enhancing technologies and reconductoring existing transmission corridors.

The report cites Edison Electric Institute data showing IOUs boosted their capital investment in transmission and distribution infrastructure 64% from 2016 to 2023, more than double the rate of inflation during the same period. EEI indicates that transmission and distribution costs rose from one-fifth to one-third of total electricity revenue requirements from 2010 to 2022.

This capital investment has been across the board, including from utilities that serve areas with slower growth of emissions-free generation, the report said, suggesting again that the rise of renewables is not driving the spending.

The report states that these cost pressures risk canceling out the potential savings offered by renewable energy, the cost of which is expected to decrease through 2030.

It offers several suggestions: Utilities can adopt better planning processes, use competitive procurement processes, maximize the capacity of the existing grid, enhance regional cooperation, refinance coal debt, adopt fuel cost-sharing mechanisms and change their business models to incentivize energy efficiency for customers rather than incentivizing their own capital investments. ■

CAISO/West News

Pathways Participants See 'Pivotal' Chance to Build New Kind of RTO

Initiative Stakeholders Seek 'RO' Processes that Elevate Public Policy, New Energy Tech

By Robert Mullin

The West faces a "pivotal" opportunity to develop a fresh approach to managing its electricity markets, one that could update RTO governance to better accommodate the public policy and new technology driving changes in the sector.

That was the view shared by some stakeholders participating in a July 12 workshop hosted by the West-Wide Governance Pathways Initiative. It was the first in a series of four virtual meetings to explore how a proposed Western "regional organization" (RO) would structure its stakeholder processes after assuming oversight for CAISO's Western Energy Imbalance Market and Extended Day-Ahead Market.

The workshops, which are being facilitated by nonprofit Gridworks, will provide a comparative examination of stakeholder processes for six RTOs and ISOs — including CAISO and SPP — and the Western Power Pool's Western Resource Adequacy Program (WRAP) to identify the best practices to be adopted by the new Western RO.

Fred Heutte, Northwest Energy Coaltion | *© RTO Insider LLC*

"I think we need a bit of a reset here, because in my mind, my perception of what we're doing with the Pathways process is to change the RTO governance model," Fred Heutte, senior policy analyst at the NW Energy Coalition (NWEC) said during the meeting.

The changes should go beyond procedural matters, Heutte said, "to reflect a new approach that combines market operations, grid dispatch and public policy, as represented primarily in state policy across all the diversity of all the different state policies across all the diverse states."

Given that emphasis, Heutte cautioned against borrowing too heavily from processes in existing RTOs.

"The amount of friction and controversy in the East because public policy is not aligned with market design and operation — it's been a problem for a long time, [and] it's a growing increasingly more difficult problem," he said.

Mona Tierney-Lloyd, head of regulatory and institutional affairs at Enel North America, "endorsed" Heutte's comments and added that Pathways is in a "unique position relative to every other organized market" to take a "fresh view" on governance.

She said her experience participating in "several markets" across the U.S. indicates that interests representing distributed resources have been marginalized and "relegated to some sub working group that isn't given the same kind of attention or weight … as other member classes."

"We're also at this really pivotal time of looking at new technologies coming online and really changing what is [recognized as] an electricity resource, looking at the distributed side of the resource equation more fully," Tierney-Lloyd said, calling it "an opportunity to take a more modern look at the way the electricity system is changing and trying to incorporate that view into a stakeholder process."

Brian Turner, Advanced Energy United's director of regulatory engagement in the West, took up that theme.

"We have the opportunity to create something new that takes the best of what is and perhaps new ideas as well. Coming from a perspective of an organization that represents a lot of the new technologies that are increasingly important in the energy system, I think that that's a perspective that is shared with nontraditional voices that have the opportunity to be represented here," Turner said.

'Fair Process'

Some workshop participants offered a more positive take on existing stakeholder processes in RTOs, particularly in the East.

Cathleen Colbert, director of CAISO market policy at Vistra, said experience working in both CAISO and PJM helped her develop a "nuanced view" of the grid operators' different approaches to stakeholder process. Colbert said she found CAISO's staff-driven process suffers from an "asymmetry" of information and access, and while the ISO provides any stakeholder the opportunity to provide input, it has no obligation to consider that input.

"Because it doesn't have any incentive to really engage stakeholders, because they don't need stakeholder support to get anything through their processes and environments … there's no incentive for them to truly be involved with their stakeholders unless you have a special relationship, unless you have figured out how to build a rapport and a relationship where you get offline access," she said.

In contrast, Colbert finds the PJM stakeholder process, with its committee structure, to be "very open … in practice."

"I don't know if it's the voting, but the PJM stakeholder process was incredibly collaborative and inclusive, versus the CAISO one, [which] is very, very hard for stakeholders to actually participate in meaningfully," she said.

Heutte said CAISO's stakeholder process is not perfect but has provided him "a relatively easy" way to submit his input on issues, while he thinks SPP's "well structured" approach can be "very isolating."

"If you're not a formal member of a committee, then you're really not treated as others are," he said. "And it's not just about the voting; it's also about who gets recognized for speaking; it's about the weight that your comments get, if you're not a formal member of that group."

Ryan Millard, senior director of West region regulatory and political affairs at NextEra Energy Resources, said "having a discussion at some point about the nuances of each process will be valuable, because maybe one process is more responsive in practice than another."

"I think having some discussion with folks that are familiar with PJM, SPP and other RTOs can kind of marry up the practical realities of how this structure actually works, and how responsive it is," Millard said.

Scott Miller, executive director of the Western Power Trading Forum, noted that some stakeholders see efficiencies in the "top-down" approach of CAISO's stakeholder process, while others see benefit to the "bottom-up" approach they've experienced in SPP's Markets+ and in some Eastern RTOs.

"The struggle, I think, is how we can get something that's very efficient, but one in which people feel it's transparent, they've got equal access, and it's a fair process," Miller said.

Huette expanded on that idea.

"It's not just the challenge of do we pick a voting-oriented approach or a nonvoting-oriented approach, but rather, what is the key challenge is to make sure that we have synchronized the stakeholder engagement process to the overall direction that we're trying to establish with this new approach to governance," he said. ■

CAISO/West News

FERC Must Apply Mobile-Sierra to Western Soft Cap Refunds, Court Finds

DC Circuit Rules with Power Sellers in Dispute over High Prices Stemming from 2020 Heat Wave

By Robert Mullin

The D.C. Circuit Court of Appeals on July 9 directed FERC to apply the *Mobile-Sierra* doctrine when it reconsiders a series of 2022 orders requiring Western wholesale electricity sellers to refund a portion of the high prices they earned during an August 2020 heat wave.

At issue in the case — and in the related FERC orders — is the commission's longstanding policy of maintaining a "soft" price cap for short-term electricity sales in the West to prevent the exercise of market power (22-1116). A product of the Western energy crisis of 2000/01, the policy requires sellers to justify the costs behind power prices exceeding the soft cap of $1,000/MWh, or refund any amount earned above the cap.

The case dealt specifically with surging prices associated with tight supply conditions stemming from triple-digit temperatures occurring over Aug. 18-19, 2020, when CAISO struggled to prevent the rolling blackouts it was forced to order Aug. 14-15 — the first such blackouts in nearly 20 years.

Wholesale prices at Arizona's Palo Verde hub on the Intercontinental Exchange (ICE) hit records of $1,515/MWh on Aug. 18 and $1,750 on Aug. 19. The hub's average price from June to August of that year, excluding the August price spike, was $52/MWh, according to filings Southern California Edison and Pacific Gas and Electric made with FERC to protest the prices.

Over the course of 2022, FERC issued a series of decisions rejecting the justifications of sellers who sold electricity at those levels during the period, finding that the ICE index prices reflected scarcity conditions and that the selling companies had failed to justify their premiums based on costs.

Those decisions rejected the argument by sellers that FERC should apply the presumptions from the 1956 cases *United Gas Pipeline v. Mobile Gas Service* and *FPC v. Sierra Pacific Power* — or *Mobile-Sierra* doctrine — to the sales and hold that the contracts were freely negotiated between the buyers and sellers and did not harm the public interest. Instead, the commission determined the *Mobile-Sierra* presumption did not prevent it from "enforcing the requirement that sales in excess of the WECC [or Western] soft price cap must be justified and [we]re subject to refund."

The commission also held that it had the authority to enforce the soft cap through refunds without conducting a *Mobile-Sierra* public-interest analysis because the soft cap was part of the sellers' filed rate, a finding reinforced by the 2002 "Soft-Cap Order" establishing the caps in the West.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In its decisions, the commission also rejected requests by some sellers to raise the West-wide soft cap to $2,000/MWh, in line with the cap in place in CAISO, saying that was out-of-scope for the rulings.

Mobile-Sierra Necessary

Dozens of sellers were affected by the decisions, including PacifiCorp, Shell, Mercuria, Tenaska, Tucson Electric Power, Uniper Global Commodities North America, Tri-State Generation and Transmission Association, and Brookfield Renewable Trading and Marketing. (See *FERC Tells PacifiCorp to Refund Premiums*, *Sellers Urge FERC to Raise WECC Soft Price Cap* and *FERC Orders More Refunds from 2020 Western Heat Wave*.)

Then-Commissioner James Danly dissented in each of the orders, questioning the commission's authority to abrogate bilateral contracts reached between buyers and sellers in a time of tight supply conditions. Danly wrote that FERC instead should have applied the *Mobile-Sierra* presumptions to the contract and found that the public interest was not harmed by upholding them.

The sellers once again used that line of reasoning in their appeal to the D.C. Circuit, contending FERC erred by not conducting a *Mobile-Sierra* analysis before ordering the refunds — an argument that swayed the court in its decision to remand the orders back to FERC.

"We agree with the sellers that the commission should have conducted the *Mobile-Sierra* analysis prior to ordering refunds, and so we grant the sellers' petitions for review, vacate the orders they challenge, and remand for further proceedings," the court wrote. "Because of that holding, the commission necessarily will need to change its refund analysis for above-cap sales going forward, and any decision by this court on the validity of that framework would be purely advisory."

In its ruling, the D.C. Circuit said FERC's arguments against administering a public-interest analysis before enforcing refunds "fail for a simple reason."

"Even assuming that the Soft-Cap Order was incorporated into sellers' tariffs and contracts, the commission did not displace the *Mobile-Sierra* presumption in the Soft-Cap Order itself, and so that presumption continues to apply to the Sellers' contracts," it found.

"More specifically, nothing in the Soft-Cap Order established that the *Mobile-Sierra* doctrine would not apply to the commission's review of any above-cap rates," the court continued. "As such, the Soft-Cap Order left intact the commission's burden of overcoming the presumption that 'a freely negotiated wholesale-energy contract meets the "just and reasonable" requirement imposed by law.'"

The court went on to say that the soft cap "is best viewed as a means for flagging for the commission contracts that may warrant public-interest analysis."

"The requirement that sellers 'justif[y]' their above-cap prices, in turn, facilitates this review by obligating sellers to supply information showing that the conditions for the ordinary application of the *Mobile-Sierra* presumption (*e.g.*, the absence of market manipulation) were in place at the time of the above-cap sale," the court concluded.

'Consumers' Petition Rejected

The court additionally rejected a petition by the California Public Utilities Commission and SCE (called the "consumers" in the ruling), which contend that FERC committed errors in its refund calculations that would lead to higher electricity prices in the future.

"We have no occasion to engage with the merits of the consumers' challenge because it is moot," the D.C. Circuit found, noting that the petitioners had questioned the way in which FERC had calculated the refunds but that the court already determined the commission had "erred in ordering refunds in the first place without applying the *Mobile-Sierra* public-interest analysis." ■

CAISO/West News

Bill to Streamline Tx Development Advances in Calif. Senate

Sponsor Assures no Compromise of Environmental Reviews

By Elaine Goodman

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California lawmakers have advanced a bill aimed at streamlining approval of transmission projects, but not before substantially stripping down the legislation.

The Senate Environmental Quality Committee voted 6-0 on July 3 to pass an amended version of *Assembly Bill 3238* by Assemblymember Eduardo Garcia (D). The bill now goes to the Senate Appropriations Committee.

As previously proposed, AB 3238 would have removed a requirement for California Environmental Quality Act (CEQA) review for the expansion of an existing right-of-way for transmission lines and equipment on state land. The provision would have applied to an expanded right-of-way up to 200 feet wide and would have expired on Jan. 1, 2030.

The project to be sited on the expanded right-of-way would still be subject to CEQA, Garcia explained during the July 3 committee hearing. He said the idea was to remove duplicative review where rights-of-way exist and land is already disturbed.

"Let me be clear … if the current version of this bill goes into effect, not one shovel will go into the ground without a CEQA review of the project," he told the committee.

But the bill was opposed by a long list of environmental and other groups. Some, including committee chair Sen. Ben Allen (D), worried about the impact on state parks.

"I'm personally not going to put my stamp on anything that's going to make it easier for folks to run big transmission lines in the middle of a state park," Allen said.

Opponents also objected to a provision in the bill that would have created a rebuttable presumption that the benefits of a transmission project outweighed its environmental impacts — if the project was included in a CAISO transmission plan.

Normally under CEQA, an agency must issue a statement of overriding consideration to allow a project to move forward despite environmental impacts.

Allen expressed concern that "we could be turning CEQA into just a rubberstamp process."

"Creating a rebuttable presumption would replace the need to provide justification and evidence that the project is truly worth [the environmental impacts]," Allen said. "That's the concern here."

The section of the bill creating a rebuttable presumption was removed. It was replaced with a statement that under CEQA, the California Public Utilities Commission "may include CAISO's factual findings regarding a project's objectives and benefits in the commission's statement of objectives and any statement of overriding considerations."

"Doing so is consistent with CEQA guidelines," the new language states. "Nothing in CEQA requires the commission to ignore such findings and it is reasonable for the commission to recognize them."

Meeting Climate Goals

Garcia said the goal of his legislation is to accelerate the buildout of electric transmission infrastructure to meet state climate goals.

"Our state has set these targets for a reason, right?" he said. "We're not going to meet them if we don't take these types of bold action."

The amended bill retained a provision setting a 270-day limit for the CPUC to complete environmental review for a transmission project and decide whether to approve it.

It would also simplify a project applicant's requirements to submit information at the beginning of the environmental review process.

Supporters of the previous version of the bill include San Diego Gas & Electric, Pacific Gas and Electric, Advanced Energy United and the California Community Choice Association. ■

West news from our other channels

Calif. Agency OKs Plan to Meet Ambitious Offshore Wind Goals NetZero Insider

CPUC Refines EPIC Program Strategic Objectives for Decarbonization NetZero Insider

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

Texas Utilities: Beryl's Damage Unlike that of Cat 1s

By Tom Kleckner

Transmission providers told Texas regulators July 11 that Hurricane Beryl's high winds deep inland in a heavily wooded region led to significant customer outages that will last more than a week after the storm's landfall.

Representatives from four of the state's primary wires carriers told the Public Utility Commission during an open meeting that more than 1.4 million customers were still without power in the Houston area. That is down from the nearly 3 million outages when Beryl came ashore July 8.

Entergy Texas CEO Eli Viamontes, who began his utility career at Florida Power and Light, said he was caught off-guard by wind speeds that exceeded 80 mph more than 70 miles from the Gulf Coast.

"I've seen many storms in my career, coming from South Florida, and the sustained winds keeping up that far inland was surprising," he said. "You combine that fact with the most densely populated area of our service territory, that also happens to be one of the most densely vegetated areas as well, you literally have that perfect combination that has caused the [outage] numbers to certainly seem higher given a Category 1, but the damage is real."

Entergy lost seven of eight major transmission ties in its footprint and 385 poles, 195 transformers and 34 substations. It peaked at 252,000 customer outages July 8 but reduced that number to just over 101,000 on July 11.

Commissioner Jimmy Glotfelty, a Houston native, got a personal view of some of the destruction the day after the storm hit when he visited a CenterPoint Energy staging site.

"I think what was astonishing in Houston was the number of large trees that were pulled up by the root ball as opposed to broken at the top," he said. "It was just pretty amazing. These aren't ones that just require chainsaws. You have to have cranes to get them out of the road, so it's kind of a different kind of storm, from my perspective."

Jason Ryan, an executive vice president with CenterPoint, said an 83-mph wind gust at George Bush Intercontinental Airport, 20 miles north of downtown Houston, was greater than the wind speeds measured during Hurricane Ike in 2008. A Category 2 storm, Ike caused an estimated $30 billion in damage in Texas and other states.

"I'll set aside whether it was a Category 1, 2, 3 or 4 hurricane," Ryan said of Beryl. "It was a significant hurricane as it came ashore and as it left our system midday."

The CenterPoint executive said the storm's path was "one of the worst paths a hurricane could take." The greater Houston area was on Beryl's "dirty side" east of the eyewall with the strongest winds and severest weather as it swirled from right to left, he said.

"The wind speeds were higher further inland," Ryan said, noting the National Weather Service issued 67 tornado watches as it pushed inland.

The level of destruction has slowed the damage assessment the utilities conduct before beginning restoration work. Ryan said CenterPoint expected to complete its damage assessment July 11. He said the company had already restored about 1.2 million homes and businesses as of July 10, leaving a little over 1 million to go. About 80% of the restoration will be completed July 14, with about 500,000 outages beginning a second week without power.

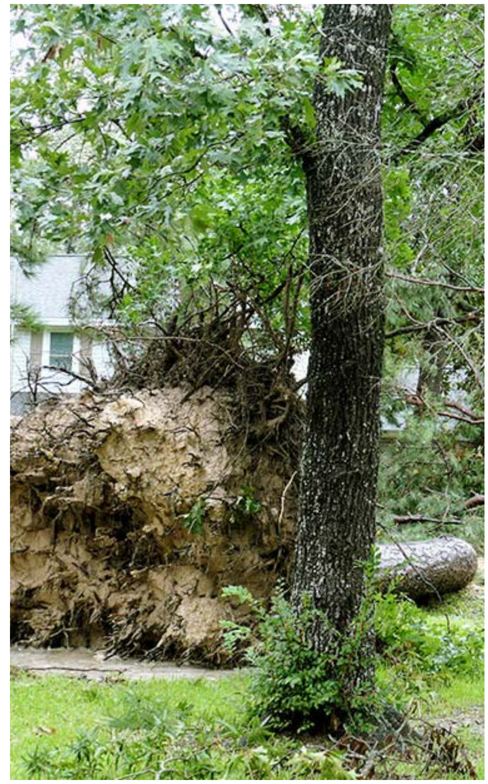
"We need to know what kind of crews to send where. That's what our damage assessment workers do in the early days after a storm," Ryan said. "If I have substantial damage to distribution poles, if I've got poles on the ground, I need to send a construction crew. If I have trees on lines, I need to send vegetation management crews to go in and clear those trees. If I can quickly restore service by doing minor work on facilities, I can send much smaller crews out to do that. We can't start sending crews out until we get that damage assessment done."

CenterPoint has borne the brunt of criticism leveled over restoration service as temperatures rise and, with it, the stress on residents *sitting in long lines for gasoline* or in crowded restaurants.

Houston Mayor John Whitmire *has said* the utility "needs to do a better job." U.S. Rep. Sylvia Garcia (D-Texas) went to social media *to tell* CenterPoint, "Your failure during this crisis is unacceptable."

Also on social media, one wag pointed out the Whataburger fast-food chain's app is a *better outage tracker* than CenterPoint's.

Texas Gov. Greg Abbott, who is on an economic development trip in East Asia, *called* for an investigation into the "multiple occasions" the Houston region has suffered through a major outage. In May, a derecho's 100-mph winds knocked 922,000 CenterPoint customers offline, some for more than two weeks; the utility has estimated it will cost *$475 million in repair work*.



Texas companies say trees torn out by their root balls have led to much of Hurricane Beryl's damage in the Houston area. | *© RTO Insider LLC*

PUC Chair Thomas Gleeson said he has had discussions with the governor's office and Lt. Gov. Dan Patrick and that "we're going to figure this out." He said the commission plans to file a report before the January 2025 legislative session with learnings from its review and "potentially some legislative solutions that we may need."

"I want to assure everybody this will be the first step in this process, not the last step," he said.

The PUC was a receptive audience for Entergy, CenterPoint, AEP Texas and Texas-New Mexico Power. The commissioners did not offer critiques of their performance but provided suggestions for better communications with their communities.

The utilities have either provided resilience plans to the PUC or will soon, a result of recent legislation. ■

ERCOT Hires New VP of Public Affairs

ERCOT announced on July 15 that it has named former American Electric Power executive Gilbert Hughes as its new vice president of public affairs, where he will coordinate communications and government affairs.


Gilbert Hughes | *ERCOT*

The grid operator said Hughes has four decades of experience in the electric utility industry, with a focus on Texas public policy. He served as vice president of external affairs for AEP, where he also had leadership positions in regulatory services, governmental affairs and community relations.

Hughes replaces Robert Black, who will serve as executive adviser during a transition period that begins immediately. Hughes will be responsible for the organization's external communications, government affairs and customer support.

ERCOT CEO Pablo Vegas said in a *statement* that a key component of meeting the state's reliability needs will be transparent communications with the public and close collaboration with state leaders and agencies, market participants and lawmakers. ■

— *Tom Kleckner*

ISO-NE News

FERC Approves New Pathway for New England Transmission Projects

By Jon Lamson

FERC has approved ISO-NE's proposal of a new process to solicit, select and allocate costs for transmission projects that address needs identified in long-term planning studies (*ER24-1978*).

Developed in coordination with the New England States Committee on Electricity (NESCOE), the new process establishes a regionalized cost-allocation method for transmission projects that are projected to bring long-term net benefits to the region. (See *NEPOOL TC Approves Process for States' Transmission Needs*.)

FERC Chair Willie Phillips and Commissioner Mark Christie concurred with the July 9 order in separate statements. Phillips commended the proposal and wrote that it does not conflict with Order 1920. Christie applauded the central role of the states within the proposal and contrasted it with Order 1920, which he argued needs "major revisions."

The approval marks the completion of Phase 2 of ISO-NE's longer-term transmission planning project; Phase 1 created a process to evaluate long-term transmission needs associated with state policies and mandates and was approved by FERC in 2022 (*ER22-727*).

In the new process, NESCOE can direct ISO-NE to issue a request for proposals for solutions to long-term needs. After soliciting proposals, ISO-NE will select a preferred solution, and NESCOE will have the option to either proceed with the default regionalized cost allocation method, submit an alternative cost-allocation method or terminate the process.

For projects to be eligible for selection, ISO-NE's analysis must indicate the quantified benefits of the project outweigh its costs.

FERC also approved a supplemental process the states can use if no proposal exceeds the cost-benefit test, allowing one or more states to cover any costs of a project that exceed this cost-benefit threshold.

FERC wrote that the tariff changes "represent a just and reasonable alternative voluntary process that will not conflict with or otherwise replace ISO-NE's Order No. 1000 regional transmission planning process."

While the comments submitted to FERC on the proposal largely were supportive, some stakeholders argued the requirement for proposals to be complete — not reliant on any additional transmission upgrades from incumbent transmission owners not included in the proposal — equates to a de facto right of first refusal. (See *Stakeholders Support ISO-NE Long-term Tx Planning Filing, with Caveats*.)

| © RTO Insider LLC

FERC ultimately rejected arguments by clean energy trade groups and merchant transmission developers that the new process would give an unfair advantage to incumbent transmission owners.

Since the process is supplemental to ISO-NE's regional transmission planning process required by Order 1000, it "need not comply with the nonincumbent transmission developer reforms established in Order No. 1000, including the requirement to eliminate any federal right of first refusal," FERC wrote.

At the request of ISO-NE, FERC also directed the RTO to submit an additional filing to fix errors in the original submission.

Phillips wrote in his concurrence that the new process is not in conflict with Order 1920 and that it "includes many of the significant components of Order No. 1920, such as multifactor planning on at least a 20-year time horizon, an *ex ante* default cost allocation method, the option for states to agree on alternative cost allocation methods and the option to voluntarily pay for the portion of a project that exceeds the identified benefit-cost ratio."

Meanwhile, Christie used his concurrence to draw a contrast between ISO-NE's proposal and the requirements of Order 1920, which he opposed. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

"The state role in this proposal is utterly contrary to the insufficient one allowed in Order No. 1920, which does not require that states consent to planning and selection criteria, does not require that states consent to an ex ante cost allocation formula, and does not even require that transmission providers have to file a state-agreed alternative to an *ex ante* formula," Christie wrote.

Christie noted the strong state support for the proposal and argued it eventually could be undercut by the requirements of Order 1920, which is on track to "force all projects, including public policy related projects, into the same bucket with other types of projects for planning and cost allocation purposes."

Christie concluded that the proposal "is the type of planning and cost allocation construct for public policy projects that the commission should encourage and approve," and called for reforms to Order 1920. ■

ISO-NE News

NEPOOL Markets Committee Restarts Work on Capacity Market Changes

By Jon Lamson

After a brief pause following FERC's approval of another delay to ISO-NE's 19th Forward Capacity Auction (FCA 19), the RTO presented the *initial scope* of its work to coordinate resource capacity accreditation improvements with proposed capacity market timing changes at the two-day NEPOOL Markets Committee summer meeting July 9-10.

The potential changes have been an extended work-in-progress for the RTO and its stakeholders. ISO-NE launched its resource capacity accreditation (RCA) project almost exactly two years ago, while the RTO has been discussing moving to a prompt and seasonal capacity market for over a year. (See *ISO-NE Starts its Capacity Accreditation Journey* and *ISO-NE Considers Major Capacity Market Changes*.)

Moving to a prompt and seasonal auction would reduce the time between the auction and the capacity commitment period (CCP) from over three years to likely just a few months, while also breaking up the yearlong CCP into seasons.

"With the FERC approval of the further delay filing, we will turn our attention to working with stakeholders on [capacity auction reform] and will not continue to study accreditation in a forward, annual framework," said Chris Geissler of ISO-NE. (See *FERC Approves Additional Delay of ISO-NE FCA 19*.)

Geissler said the key considerations for the project scope are making sure the work is finished in time to implement for the 2028/29 commitment period (CCP 19), prioritizing the highest-value reforms and avoiding adding components that jeopardize the overall timing or development of the key aspects.

The new capacity market design "likely needs to be completed, filed and approved well in advance of CCP 19," Geissler said. "Expect that this will require hard decisions because even the most narrow project scope that achieves a prompt and seasonal market with accreditation reforms requires enormous design and implementation efforts."

The core aspects of the capacity auction reform (CAR) will include defining the exact timing of a prompt and seasonal auction, determining how entering and retiring resources will be treated under this construct, developing seasonal demand curves and incorporating the work that has already been completed on

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

capacity accreditation into the new auction format.

Geissler said ISO-NE and stakeholders have already made "significant progress" on developing a new accreditation method, but "outstanding areas remain and further changes are necessary with a prompt and seasonal capacity market."

The project will likely include work on a new approach to accounting for gas constraints, along with an update to the current cost of new entry value, since "accreditation reforms and modeling changes would impact this value, which is used to derive the capacity demand curves," Geissler said.

Geissler said ISO-NE is also contemplating moving from a descending clock to a sealed bid auction format, developing simultaneous seasonal bidding to account for resources that could receive an obligation for just one season, and accounting for resource startup times in accreditation.

ISO-NE is contemplating whether to submit CAR's resulting tariff changes as a single filing or a series of filings. For changes that ISO-NE is unable to complete for CCP 19, Geissler noted that the RTO could explore "improvements and enhancements for later commitment periods, after CAR has gone into effect."

Internal Market Monitor Report

Wholesale market costs were down in 2023 relative to the prior year, falling back to the levels seen prior to the spike in natural gas prices, Donal O'Sullivan of the ISO-NE Internal Market Monitor said in presenting takeaways from the Monitor's 2023 *annual markets report*.

The lower costs were in part spurred by the lowest loads experienced in the region "since at least 2000 due to mild weather conditions and the growth in behind-the-meter solar generation," O'Sullivan said.

He added that renewables have grown gradually in the region over the past five years but said "the combined impact of behind-the-meter solar and wholesale market solar on load and pricing [time-of-day] profiles is noticeable."

The annual report found that the energy market accounted for about 51% of wholesale costs, followed by transmission at 28% and the capacity market at 13%. The Mystic cost-of-service agreement accounted for about 5% of total costs.

While transmission costs were high, "the market impacts of investments are evident in terms of low congestion, fewer local reliability and voltage commitments, and [fewer] local market power issues," O'Sullivan said.

Looking at the resource mix, natural gas generation continued to increase despite the historically low loads. It accounted for 48% of total supply in 2023, compared with 45% in 2022 and 39% in 2019.

In contrast, imports to the region were down, in part because of an approximately 20% reduction in imports from Canada because of lower reservoir levels, O'Sullivan said.

Hourly Tracking Proposal Fails to Pass

A proposal by Constellation Energy to enable hourly tracking of generation by the NEPOOL Generation Information System failed to pass the MC with 65.1% in favor, falling just short of the two-thirds majority needed to pass.

The company has *argued* that enabling hourly tracking would cost ratepayers relatively little and would help boost the market for carbon-free generation that matches load.

NEPOOL *estimated* that upgrading the system to accommodate the proposal would cost $75,000.

Opposition to the proposal came from members of the end user sector and the publicly owned sector. Opponents made the case that the proposal would benefit companies selling certificates at the expense of ratepayers and is not required by regulation.

The proposal now heads to the NEPOOL Participants Committee. ■

ISO-NE News

The Rocky Road to Performance-based Regulation in Conn.

By Jon Lamson

In the sometimes sleepy world of utility ratemaking, Connecticut is frequently making headlines over public disputes between the state's utilities and their regulators.

The feud reached a boiling point in May when Eversource Energy announced plans to reduce its investments in the state by $500 million over the next five years. (See *Eversource Announces $500M Cut in Connecticut Investments*.)

Eversource and Avangrid — which own the major investor-owned utilities in the state — have decried actions taken by Public Utilities Regulatory Authority (PURA) ChairMarissa Gillett, arguing the agency's approach to several recent rate cases jeopardizes the utilities' ability to receive a fair return on their investments.

Meanwhile, Gillett has *made the case* that the agency is simply holding the utilities accountable to existing standards, albeit more strictly than in the past.

The dispute comes at a critical time for the state's power grid, which is facing a significant expansion to accommodate electrification and increasing volumes of renewable generation. It also comes as Connecticut undertakes a major shift — at the behest of the state legislature — to how it regulates electric utilities.

While New England has experienced a broader trend towards stronger utility performance incentives in recent years, Connecticut is the first state in the region to undertake a full-scale shift to performance-based regulation (PBR).

Ultimately, the success of Connecticut's transition to PBR could have significant implications for the state's clean energy transition, the cost and reliability of its electricity, and the proliferation of PBR approaches throughout the broader region.

Misaligned Incentives

In the traditional cost-of-service model, regulators determine utility revenues based on operational expenses, capital investments and an allowed rate of return on investments. While efforts to reform traditional ratemaking predate the clean energy transition, there has been a growing recognition that changes to the basic cost-of-service model are needed to accommodate the changes that are underway.

PBR encompasses a wide range of regulatory approaches including financial incentives and penalties, performance metrics and scorecards, multi-year rate plans, and revenue decoupling, all aimed at achieving goals and outcomes not explicitly considered in traditional ratemaking.

The Connecticut State Capitol in Hartford | *Shutterstock*

"Under cost-of-service regulation, we see a real tension between the kinds of investments that earn utilities an allowed rate of return and those they pass on to customers as operating expenses," Oliver Tully, director of utility innovation at the Acadia Center, told *RTO Insider*. "We see a situation where the high capital-cost investments may not be the ones that are actually best for ratepayers and the grid overall."

Traditional regulation, Tully said, can lead to "a clear misalignment between the incentives that the utilities face when making investment decisions and the policy priorities that the states have, especially around clean energy, equity, greenhouse gas emissions and affordability."

Some of the top regulators in New England have also highlighted this dynamic. At a conference in June, Chair Jamie Van Nostrand of the Massachusetts Department of Public Utilities brought up the "cap-ex bias" of investor-owned utilities. (See *State Regulators Discuss Affordability, Utility Incentives at NEECE*.)

"Utilities tend to want to build more stuff because they get to put it into the rate base and get a return on it," Van Nostrand said, adding that regulators should consider "incentive mechanisms to align [the utilities'] interests with our interests in pursuing clean energy goals and maintaining affordability."

This sentiment was echoed by Philip Bartlett, chair of the Maine Public Utilities Commission, who said "we definitely need to move [toward] stronger performance incentives that are really driving outcomes."

In the coming years, the states with strong decarbonization goals will rely on utilities to help implement demand reduction programs, utilize new technologies to optimize the existing grid and facilitate the deployment of an increasing amount of distributed generation. For advocates of PBR, incentives beyond the cost-of-service model are necessary.

But in Connecticut, which has pushed to implement the most aggressive PBR framework in the region, the development process has served as another stage for clashes between the utilities and PURA.

Shifting Winds in Connecticut

In the late evening of Aug. 3, 2020, Hurricane Isaias made landfall in North Carolina, weakened to a tropical storm, and accelerated inland roughly 100 miles parallel to the coast up through Vermont, eventually dissipating in Québec. The storm left immense destruction in its wake, causing 10 deaths and almost *$3.5 billion* of damage in the Northeastern U.S.

In Connecticut, Isaias triggered lengthy power outages and, several years later, major new legislation to address concerns about what many lawmakers saw as poor utility performance in response to the storm. Passed in 2023, the state legislature's Take Back Our Grid Act directed PURA to create a performance-based framework for regulating the state's electric utilities.

This PBR framework is still in development, with opinions on the current structure varying widely depending on who is asked.

According to the state's utilities, PURA has largely ignored their concerns, resulting in a proposal that would prevent the utilities from making a reasonable rate of return, and ultimately reduce investments in the state's grid.

"There's no transparency as far as I can see into how PURA's formulating it's vision of what PBR is," said Doug Horton, vice president of rates at Eversource, calling for more "collaboration and coordination" in the PBR development process.

"We don't expect to get everything that we

ISO-NE News

want, but we expect to be heard, and in Connecticut that's just not been the case," Horton said.

Representatives from Avangrid echoed Eversource's concerns about PURA's approach, arguing that the agency needs to better incorporate the perspectives of the utilities, investors, commercial and industrial end users, and local governments.

But according to organizations representing environmental and consumer advocates, the proceedings have been collaborative, and PURA has been intentional about including a wider range of perspectives than have historically been involved in utility proceedings.

"There has been a great deal of resistance from the electric distribution companies," said Shannon Laun, vice president at the Conservation Law Foundation. "I think it is troubling that they've really been personally attacking the regulators at PURA and have made some pretty outrageous claims that the process has not been collaborative and has not taken into account their perspective."

Laun emphasized that PURA "really has gone above and beyond to make this a collaborative process."

Connecticut Consumer Counsel Claire Coleman said the PBR proceedings have been "a thoughtful process" featuring "a broad range of stakeholders," while stressing that there is a still lot of work left to do.

PURA issued a ruling on the first phase of the PBR proceedings in April 2023, setting out the "regulatory goals, foundational considerations and priority outcomes to guide PBR development." It also established three dockets for the second phase of the proceedings, centered around revenue adjustment mechanisms, performance mechanisms and integrated distribution system planning.

PURA is now holding technical sessions for each of the three ongoing PBR dockets, with final decisions on the dockets on track for mid- to late 2025.

The utilities' concerns about the PBR framework — and the general regulatory environment in the state — ultimately boil down to the rate of return they expect to receive on their investments. Several recent high-profile rate cases have spurred outcry from the utilities about their ability to attract investors, and credit rating agencies have downgraded the outlooks for Connecticut utilities in recent years.

According to Horton, the proposed framework appears to "arbitrarily set rates less than our costs … and that on its own will cause PBR to fail."

He added that the framework would only push investors away, which would disincentivize the utilities from spending money in the state.

Javier Bucobo, vice president of regulatory affairs at Avangrid, said the current structure would account for inflation on a delayed timeline, and contains performance metrics that appear unattainable.

"It's setting up the utility to fail," Bucobo said. "That's the exact opposite of what PBR is for."

In contrast, Coleman, along with environmental advocates involved in the proceedings, has a less catastrophic view of the credit downgrades and the PBR proposals.

Regarding the credit downgrades stemming from recent rate cases, "we acknowledge that there is an impact, but it is almost a tertiary impact to consumers," Coleman said.

While cost-of-debt increases could ultimately result in some higher costs for ratepayers, utility rate increases are "a much more immediate cost to customers," she added.

"What we've said is PURA needs to focus on the legal standard, which is: are the utilities receiving what is sufficient-but-no-more-than-sufficient to keep their business going," Coleman said. "That really is the correct analysis, as opposed to speculating about how the investment community is going to react."

Ultimately, Coleman expressed her hope that the new PBR framework will eventually help the utilities' credit ratings by increasing the certainty around how the utilities can recover their costs, while also meeting the state's performance goals.

Despite the utilities' vocal concerns, Bucobo and Horton agreed that it is not too late to develop a PBR framework that can work for everybody.

"It can be turned around," said Bucobo. "It's as easy as having a conversation, and we're willing to do that."

'A Model for Other States to Follow'

In New England, PBR at some level already exists in "basically every state," said Mark Lowry, president of Pacific Economics Group and a leading expert on PBR. "New England was one of the very first to have these multiyear rate plans, and now almost every state is going to have it — that's pretty amazing."

Across the U.S, Hawaii is the furthest state along in implementing a comprehensive performance-based framework similar to Connecticut's ongoing proceeding.

Lowry said Connecticut "was drawn to this very outwardly consumer-friendly PBR approach in Hawaii but didn't even have the utility protections that there are in Hawaii, much less the ones that are commonplace elsewhere in New England."

At the same time, Lowry said that the state appears to be reconsidering some of its approach to PBR, adding that "certainly some of [Chair Gillett's] instincts are correct to second-guess some of what the utilities are saying … maybe Connecticut regulation has been kind of stodgy in the past and needed some fresh air."

While Connecticut has opted to dive headfirst into PBR, other New England states have taken a much more incremental approach to adopting utility performance mechanisms, said Nathan Phelps of Vote Solar.

"There's been little policy tweaks here and there in order to move towards what I would consider PBR," Phelps said.

In Maine, a recent legislative PBR proposal died in the House of Representatives, with opponents *citing* the controversy that has surrounded implementation in Connecticut.

Some advocates have expressed concern that the pushback to Connecticut's proceeding could discourage other states from considering the pursuit of comprehensive PBR.

Tully of the Acadia's Center said that, while he views the Connecticut proceeding as "a model for other states to follow," he has been disappointed by the utilities' response and is "a little bit fearful of what this could mean for other states."

In New Hampshire, Eversource included a PBR proposal in a rate case it filed in May. New Hampshire Consumer Advocate Don Kreis called the proposal "a reasonable basis to begin discussions with the utility about what a fair and reasonable performance-based ratemaking initiative would look like."

But regarding the struggles in Connecticut, Kreis said he would "resist any attempt to try to turn New Hampshire into the anti-Connecticut," and said it is a "key imperative" for PBR to have a balance of rewards and consequences.

"The utility has to put skin in the game," Kreis said. ■

MISO News

MISO: Sloped Curve Would Have Raised 2024/25 Capacity Auction Prices

By Amanda Durish Cook

CARMEL, Ind. — As it gears up to run its first auctions using sloped demand curves, MISO last week said prices and procurement would have risen had it used them in this year's auctions.

Over summer, several local resource zones would have experienced a six-fold jump in clearing prices, the grid operator revealed at the Resource Adequacy Subcommittee's meeting July 10.

MISO used prototype curves that it presented to stakeholders last year to hypothetically redetermine clearing prices and additional supply procurement for the 2024/25 capacity auction. In reality, seasonal sloped demand curves will differ because the RTO will periodically update calculations that draw on historical operating costs of generators in the footprint.

MISO will have sloped demand curves in play for the 2025/26 planning year auctions after FERC last month allowed the RTO to use them in place of the vertical demand curve it had been using since 2011. (See *FERC Approves Sloped Demand Curve in MISO Capacity Market*.)

For zones 1-4, 6 and 7, clearing prices this year would have jumped from \$30/MW-day to \$197/MW-day in summer, from \$15 to \$39 in fall and from 75 cents to \$2.40 in winter. In the same zones, spring prices would have dropped from \$34 to \$32.

MISO South clearing prices would have increased less dramatically in summer, from \$30/MW-day to \$80/MW-day, but it followed the other zonal prices in the other seasons. MISO's reenactment of the 2024/25 auction showed the Midwest-to-South transfer constraint binding on its limit, causing the lower summer prices between South and Midwest.

For Missouri's Zone 5, which this year experienced an 872-MW shortage in fall and a 196-MW deficit in spring, prices would have tracked other Midwest zones in summer and winter but risen from the \$720/MW-day cost of new entry (CONE) price limit to \$758 in fall and \$751 in spring. (See *Missouri Zone Comes up Short in MISO's 2nd Seasonal Capacity Auction, Prices Surpass \$700/MW-day*.)

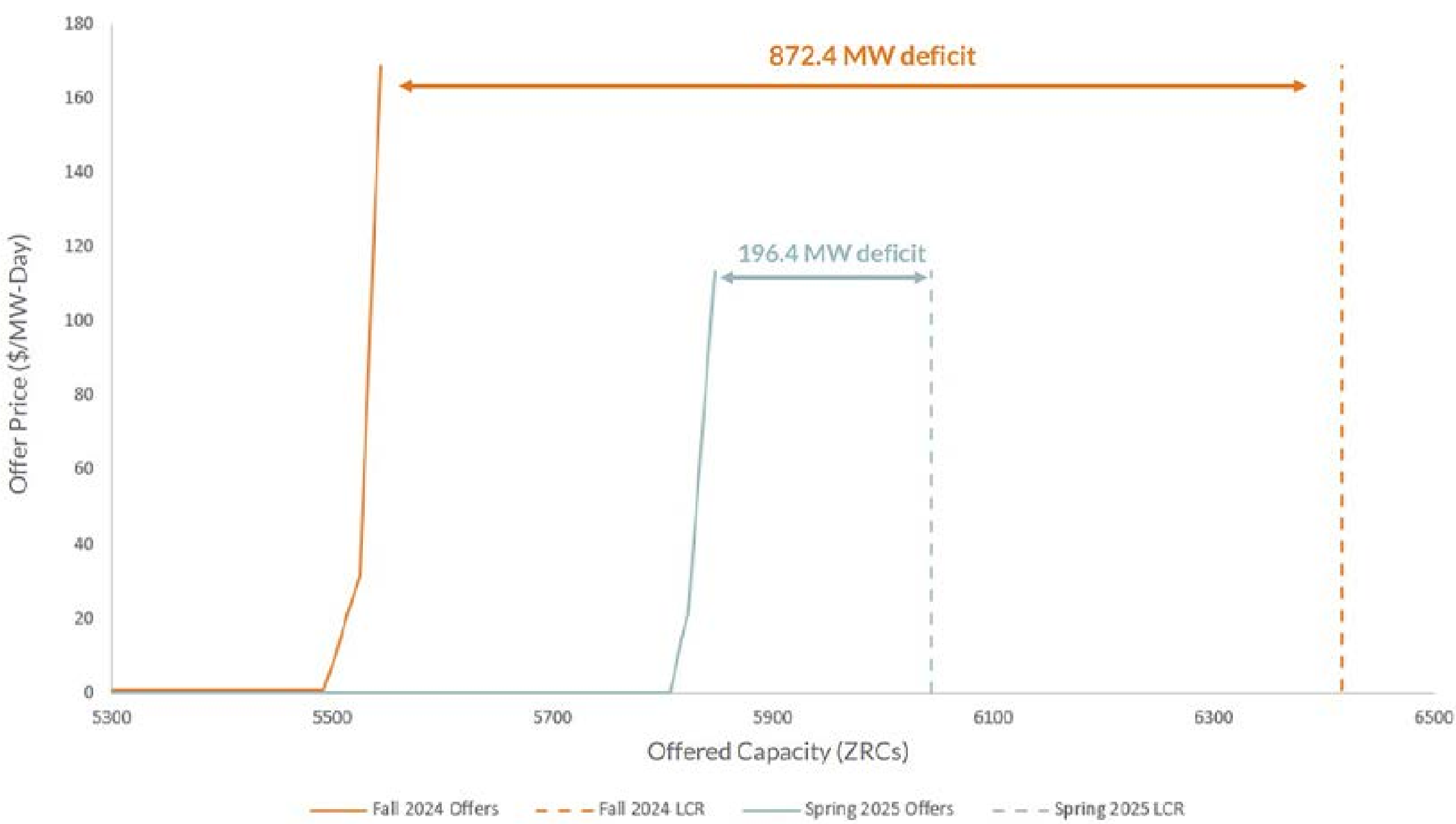
MISO did not alter capacity offers made in the 2024/25 auction for its reenactment.

The sloped demand curve design paired with MISO's new seasonal auctions allows clearing prices to go as high as four times the CONE. The curve is meant to value capacity beyond what's strictly necessary to meet the one-day-in-10-years loss-of-load expectation.

Alongside the higher prices, an indicative rerun of the 2024/25 auctions showed that with a sloped demand curve, MISO cleared capacity beyond its reliability targets, except in spring: 4 GW more in summer; over 4 GW more in fall; and 3 GW more in winter.

However, spring cleared nearly 127 GW, lower than the nearly 128-GW target. But MISO said the prototype demand curves show that shortages will likely need to be more pronounced in the future to trigger CONE pricing.

MISO staff did not venture a guess as to whether Zone 5 still would have returned a shortage had the sloped demand curve been used in 2024/25. Neil Shah, senior manager of market design, said there were too many factors at play in Zone 5 to say for certain what would have transpired. ■



Zone 5 fall and spring offer curves and LCR | *MISO*

MISO News

MISO Monitor Spotlights Congestion Fixes, Market Mismatches in 2023

By Amanda Durish Cook

MISO's Independent Market Monitor debuted six new market recommendations this year as part of his annual State of the Market report, released last month.

Two of the *recommendations* this year stem from MISO's ongoing struggle with expensive transmission congestion. Independent Market Monitor David Patton said the RTO's congestion management would improve if it could decommit resources that were committed in the day-ahead market.

Addressing the MISO Board of Directors' Markets Committee in a July 11 teleconference, Patton said the RTO doesn't have a process to ask day-ahead committed resources to stand down, even when they contribute to "severe congestion." MISO could likely save several million dollars in congestion costs annually if it had a process for requesting resources to abandon their day-ahead obligations, he said.

MISO should further develop procedures outlining when it's appropriate for its operators to derate transmission constraints to manage congestion, Patton recommended. Operators have inconsistently applied deratings, and those out-of-market actions have produced an average of $200 million in congestion costs for the past two years. He said MISO doesn't have a "clear procedure" that indicates when its operators should implement deratings.

"While it's important to derate transmission, we should only derate the transmission when it's necessary," Patton said.

Outage Details

Beyond that, Patton recommended that MISO compel generation owners to fill out the reasons behind outages or outage extensions in the ticketing system the RTO uses to track scheduling.

Patton said MISO should be requiring "clear reasons" behind outages and extensions. He said better explanations will help its understanding of the nature of outages.

"In a lot of cases, the reason for the outage is unclear or left blank," Patton told the board.

Patton said descriptions have become more important because now outages can count against resources' capacity accreditation. "Accurate outage reporting informs operations — and monitoring — in the short run and is critical for capacity accreditation in the long run."

Patton: More Sloped Curves

On the capacity auction front, Patton recommended that MISO use demand curves at the zonal level to better model demand in its local resource zones and produce more accurate local clearing requirements.

Patton said he was puzzled that MISO didn't develop a plan for zonal-level curves alongside its successful bid with FERC to use sloped demand curves in the auction at the subregional and footprint-wide level. (See *FERC Approves Sloped Demand Curve in MISO Capacity Market*.)

Without the use of zonal curves, zones that bind on either their export or import limits in the capacity auction could experience clearing prices that have little to do with reliability value, he said.

Patton said the capacity auction this year cleared "inefficiently high shortage pricing" in Missouri's Zone 5, which hit $720/MW-day in spring and fall. Missouri's expected unserved energy from the shortage isn't as risky as the clearing prices suggest, he argued.

Nevertheless, Patton called it an "amazing step in the right direction that we now have" sloped demand curves to value capacity.

Market Recommendations

Patton said MISO could improve market performance if it aligned its definition of aggregate pricing nodes between its financial transmission rights market and real-time and day-ahead markets.

Currently, the aggregate pricing hubs in the FTR market change with new load. On the day-ahead and real-time markets side, load additions do not influence the aggregation of pricing nodes. Patton said MISO's influx of large, uneven loads has caused aggregate pricing nodes in the FTR market and day-ahead and real-time markets to vary "substantially." He recommended that MISO eliminate discrepancies in aggregation definitions between the markets.

"You would like these aggregation zones to be identical. But in a number of cases, they're not," Patton said.

Multiplying data centers and cryptocurrency mining facilities will exacerbate the problem, he added. Patton called his recommendation "complicated but fairly important."

MISO should begin looking into studying loads like it does interconnecting generators in the queue, Patton said, because large loads can also affect the transmission system and necessitate upgrades.

MISO's Markets Committee of the Board of Directors in March | © *RTO Insider LLC*

"Some of these large loads create comparable problems to generation that's interconnecting," he said.

Patton also said this year he revived an old recommendation to enforce requirements for MISO's 30-minute reserve products. He explained that MISO often commits resources outside of the market to solve voltage and local reliability issues in load pockets. He said in some cases, shortages that weren't priced have occurred in load pockets.

Those situations would be best handled by allowing the market to naturally summon short-term reserves to maintain reliability, he said. The problem is most pronounced in East Texas, where MISO has come close to shedding load. Patton said that if MISO honored a requirement to use reserves instead of out-of-market actions, generation owners might be motivated to build more generation or delay retirements.

MISO is reviewing the Monitor's recommendations and will deliver a public reaction to the State of the Market report in October.

At the end of the Markets Committee teleconference, Clean Grid Alliance's David Sapper criticized MISO's timeline for reviewing the State of the Market report for not setting aside enough time for stakeholders to discuss the merits of the Monitor's recommendations.

Sapper said stakeholders have only minimal time at a single Market Subcommittee meeting to react to the recommendations and aren't allowed in on the process of MISO determining which recommendations should be taken up and which can be disregarded or delayed. ■

MISO News

MISO Proposes to Split LMR Participation and Accreditation into Fast/Slow Groups

By Amanda Durish Cook

CARMEL, Ind. — MISO said it likely will split load-modifying resource participation into two options in an effort to line up their true contributions with accreditation.

MISO's Joshua Schabla said the RTO is considering "flexible and rigid" capacity-only demand response participation options for LMRs.

Stakeholders learned at a July 10 Resource Adequacy Subcommittee (RASC) that MISO wants to introduce a category for LMRs that take longer than 30 minutes to react. Those LMRs would be tasked with responding to the first step of a NERC Energy Emergency Alert and their accreditation would be based on response times and availability.

The second class of LMRs would commit to be available for deployment in 30 minutes or less for the second step of a NERC Energy Emergency Alert (EEA 2). Those resources would have to be able to respond to an unlimited number of EEA 2 events. Currently, LMRs must respond up to five times apiece in summer and winter months and up three times in spring and fall, and MISO must reach an EEA 2 to access LMRs.

Under the pair of options, LMRs' must-offer requirement would kick in during MISO's capacity advisories or emergency declaration hours. The first set of LMRs would submit their real-time availability through MISO's market user interface for MISO dispatch; the second set of LMRs would continue to communicate availability through MISO's demand-side response interface for scheduling instructions.

MISO said it may rename one of the two categories to something other than LMR. The grid operator warned stakeholders in May that it needs to reassess its LMR concept and requirements. (See *MISO Says Risk Driving It to LMR Reorganization, Stronger Requirements*.)

Zak Joundi, MISO | *© RTO Insider LLC*

MISO first proposed in spring that all LMRs should be available in 30 minutes or less, with those unable to meet those response times relegated to participating as demand response resources. It's since walked back that proposal after stakeholder criticism. Multiple stakeholders argued that the 30-minute minimum was too drastic and that MISO was trying to treat LMRs — with characteristics that vary wildly — the same.

Schabla said one lenient and one rigorous LMR class should allow most of MISO's 12 GW of LMRs to continue participation in MISO with a more honest stock of their abilities.

"We want to be mindful — compassionate, frankly — about what these resources are capable of," he said. "There still is value to resources that take longer to respond."

MISO hasn't yet landed on a maximum response time it will accept from the slower class of LMRs. Currently, MISO LMRs have a requirement to be ready in six hours or less.

Schabla said the type of participation LMRs opt for and how quickly they can respond will set the value of their capacity accreditation, with LMRs participating in the second category naturally receiving the most capacity value. However, he said MISO has yet to work out "firm numbers" behind accreditation calculations and will release more detail on the methodology in August.

Bill Booth, consultant to the Mississippi Public Service Commission, asked if MISO had to upend its current LMR construct at all and if it could instead simply create a "super LMR" category for the fastest resources.

Schabla said the second participation option can be thought of as the "super LMR."

Sustainable FERC Project's Natalie McIntire thanked MISO for incorporating nuance into LMR accreditation and allowing resources the chance to help the system based on their ability.

Other stakeholders weren't as convinced.

Executive Director of Market Innovation Zak Joundi asked stakeholders to be open-minded about MISO's proposal, though they might not like it. He said MISO is trying to capture the value of LMRs based on how they perform.

"We are trying to better utilize this asset class. Period," Joundi said. He said when the LMR class was created, MISO had a large surplus and virtually never used them. Now, Joundi said an increasingly intermittent fleet and volatile weather means MISO and stakeholders should rethink LMRs as something MISO needs to tap into more often.

"Going forward this is 12 GW that we are likely to leverage, and we need to have the visibility and the confidence that we can utilize them," Joundi said.

MISO has said its historical data shows actual LMR availability always is lower when compared to the cleared LMR capacity in Planning Resource Auctions. It also has said some LMRs clear auctions without ever making themselves available.

WEC Energy Group's Chris Plante said his control room operators currently "don't have a full grasp of what they're supposed to be reporting and when." He said MISO isn't clear about what it expects of LMRs, and it should address that first before reinventing LMR participation.

Plante called MISO's proposal a "complete divergence of what LMRs have been."

Joundi reminded stakeholders the LMR accreditation isn't set to go live until the 2028/29 planning year. He said MISO is working in parallel to be clearer about what it expects of its LMRs.

"MISO seems to be proposing solutions before it understands what the problems really are. That's unfortunate," WPPI Energy's Todd Komplin said.

Komplin introduced a *motion* and vote in the RASC urging MISO to better investigate the gulf it reports between LMRs' reported availability and the capacity LMRs clear in auctions. He also asked MISO to investigate why its control room operators are "effectively using LMRs to address capacity emergencies."

MISO market participants will vote via email on the RASC motion over the next week.

Komplin said MISO is not explaining why a six-hour lead time on LMRs no longer is sufficient and why it needs LMRs readied in as little as 30 minutes.

Joundi said the motion likely would result in MISO examining what it can do to support LMR contribution. But he qualified that research would occur simultaneously alongside the new participation and accreditation proposal for LMRs. ■

MISO News

MISO Subcommittee to Act on Bad Actor Demand Response

By Amanda Durish Cook

CARMEL, Ind. — MISO's Market Subcommittee will assist MISO in drafting tariff requirements to discourage market participants from committing fraud in MISO's demand response market.

At a July 9 Market Subcommittee meeting, MISO principal market design adviser Michael Robinson presented draft rewording and additional paragraphs in its tariff to "address inappropriate behavior by certain market participants."

Robinson said MISO is taking suggestions from stakeholders on how it can tweak its tariff redlines to best deter fraudulent demand response. The grid operator hopes to have rules ready to file with FERC at the end of the year.

Over the past two years, FERC staff have caught three companies manipulating MISO's demand response market and collecting unjustified payments. The commission found that an air separation facility in Indiana accepted payments for phantom load reductions, an Arkansas steel mill engaged in a yearslong failure to reduce electricity use, and an obscure, Texas-based LLC formed to sell in-car ketchup holders fraudulently enrolled customers and made faux DR offers in three capacity auctions. (See *FERC Catches Ketchup Caddy Co. in Another Fake DR Scheme in MISO*.)

Michael Robinson, MISO | © *RTO Insider LLC*

Robinson said MISO plans to shut down avenues for demand response resources to be paid for artificial curtailments or over-collect when they deliberately inflate their baseline electricity use to exaggerate reductions. Likewise, MISO wants to make it more difficult for companies to enter fraudulent registrations, where unwitting end-use customers are entered into DR contracts without their consent.

Robinson referenced Baltimore's Camden Yards DR scandal a decade ago, where management would turn the baseball stadium's lights on when the Orioles weren't playing to ratchet up baseline use and make cuts to load look more dramatic. He also said MISO's now-infamous Ketchup Caddy episode falls under the fraudulent registration category.

MISO is vetting draft tariff language with stakeholders that would have demand response resources providing proof of contracts and hourly meter data and making executive attestations to their reductions.

MISO also is considering screening DR offer parameters to ensure they are consistent with a resource's ability and setting specifications on how and when DR resource testing must occur to weed out baseline manipulation. It's also mulling excluding reduction hours from baseline use calculations, rather than excluding the entire days when reductions occur.

MISO's Neil Shah said the new requirements are motivated by the recent demand response deceptions that FERC staff have uncovered.

Michigan Public Power Agency's Tom Weeks asked if MISO also is working in more examination and auditing of companies that register for demand response participation but could appear suspicious.

Robinson confirmed MISO is working on bolstering its screening process and is in discussions with the Independent Market Monitor about how to best detect sham DR. ■

Renewable Group Asks MISO Community to Consider HVDC Capacity

By Amanda Durish Cook

CARMEL, Ind. — A renewable energy trade group has asked MISO to put more thought into how HVDC transmission's ability to infuse the footprint with more external capacity could influence MISO's capacity auctions.

The Southern Renewable Energy Association approached MISO and stakeholders at the July 10 Resource Adequacy Subcommittee, asking them to consider that HVDC lines can deposit far-flung generation into MISO's local resource zones.

"In a lot of ways, this conversation is overdue. … We should be talking more about this," SREA Transmission Director Andy Kowalczyk said. He said MISO promised more discussion on supply facilitated by HVDC in a FERC docket in 2018, but so far MISO hasn't engaged stakeholders (ER18-2363).

Kowalczyk said HVDC-enabled capacity in the Planning Resource Auction raises questions over how those resources will clear, be priced and accredited.

He said Grain Belt Express stands to deliver substantial wind energy from Kansas and asked stakeholders to consider if generation carried by HVDC should clear at the zonal price in MISO where the line terminates.

Kowalczyk also said it might make sense for MISO to model increased capability of resources utilizing an HVDC line in its loss of load expectation studies.

He added that he didn't want to "overhype" HVDC's capabilities, but said the lines stand to deliver power during critical times. He said an HVDC system could impact MISO's reliability planning.

"There aren't any downsides to exploring this issue and resolving a policy gap," Kowalczyk said.

The Resource Adequacy Subcommittee agreed by consent to take up the issue at future meetings. ■

| Siemens

MISO News

MISO to Limit Use of $10K VOLL During Long-duration Outages

By Amanda Durish Cook

Chuck Hansen, MISO | *© RTO Insider LLC*

CARMEL, Ind. — MISO said stakeholders have convinced it to design an off switch on its proposed $10,000/MWh value of lost load to use during extended load-shedding events.

Speaking at a July 9 Market Subcommittee meeting, MISO's Chuck Hansen said the RTO will work a "circuit breaker" into its new VOLL for load shedding that lasts longer than four hours.

MISO early this year proposed using a $10,000/MWh value of lost load, nearly three times the amount of its current $3,500/MWh. (See *MISO Wants $10K VOLL, a Nearly Threefold Increase*.)

Hansen said MISO foresees using VOLL for "a few intervals, maybe up to a few hours" at a time, but not over several hours and days. He said MISO is considering placing a three-step maximum value on VOLL pricing during extended periods of load shedding.

MISO said it plans to cut VOLL in half to $5,000/MWh after four hours of load-shedding during a maximum generation emergency. When active load-shedding measures aren't lifted in time for MISO's 10:30 a.m. ET day-ahead market closing, MISO will extend the lower, $5,000/MWh VOLL into the next operating day. For load-shedding that continues into a second day and beyond, MISO will slash its day-ahead and real-time VOLL to $2,000/MWh for successive operating days.

"It's something the market's not seen. But if we get to that point, we believe it's best to limit pricing on extreme, multiday events," Hansen said. "We don't anticipate such an event, but it's prudent to prepare for such an event."

Hansen said the $2,000/MWh step can continue indefinitely until the maximum generation emergency is terminated and normal operations resume. He said MISO landed on the $2,000/MWh amount partly because it's the hard cap on incremental energy offers in FERC's Order 831.

Hansen said while MISO wants to set prices to incent responses, there's a point where "high prices aren't enhancing reliability and are creating a high financial risk to participants." He said it's not appropriate to have "indefinite" pricing at $10,000/MWh when it's not helping resolve a situation.

Stakeholders months ago voiced apprehension over the potential for prolonged, prohibitively high prices and the cost exposure to customers under MISO's proposed higher VOLL.

The Organization of MISO States "strongly" encouraged MISO to include a circuit breaker mechanism in its VOLL design. Entergy also said there's "no disagreement that [a prolonged scarcity event] could occur and cause severe financial distress and harm."

Hansen said MISO is hoping to present "straightforward" tariff language at the August Market Subcommittee meeting and its proposed VOLL boundaries sometime in the fall. ■

NYISO News

NYISO Monitor: NYC Capacity Costs Rose 221% in Q1

By Vincent Gabrielle

New York City saw a 221% increase in capacity costs in the first quarter because of the retirement of over 600 MW in peaker plants and the increase of more than 300 MW in the local installed capacity requirement, NYISO's Market Monitoring Unit told stakeholders July 10.

Capacity costs elsewhere in the state rose "modestly," Potomac Economics said in presenting its first-quarter State of the Market *report* to the Installed Capacity Working Group.

Overall, the MMU found that the market performed competitively in the first quarter. But spot capacity prices rose by 311% in New York City over the first quarter of 2023. The city's ICAP requirement was increased because of higher load forecasts.

All-in prices ranged from $38/MWh in the North Zone to $81 in New York City. Prices rose west of the Central-East interface and the city while falling in the rest of Eastern NY. Potomac attributes this partially to falling natural gas prices.

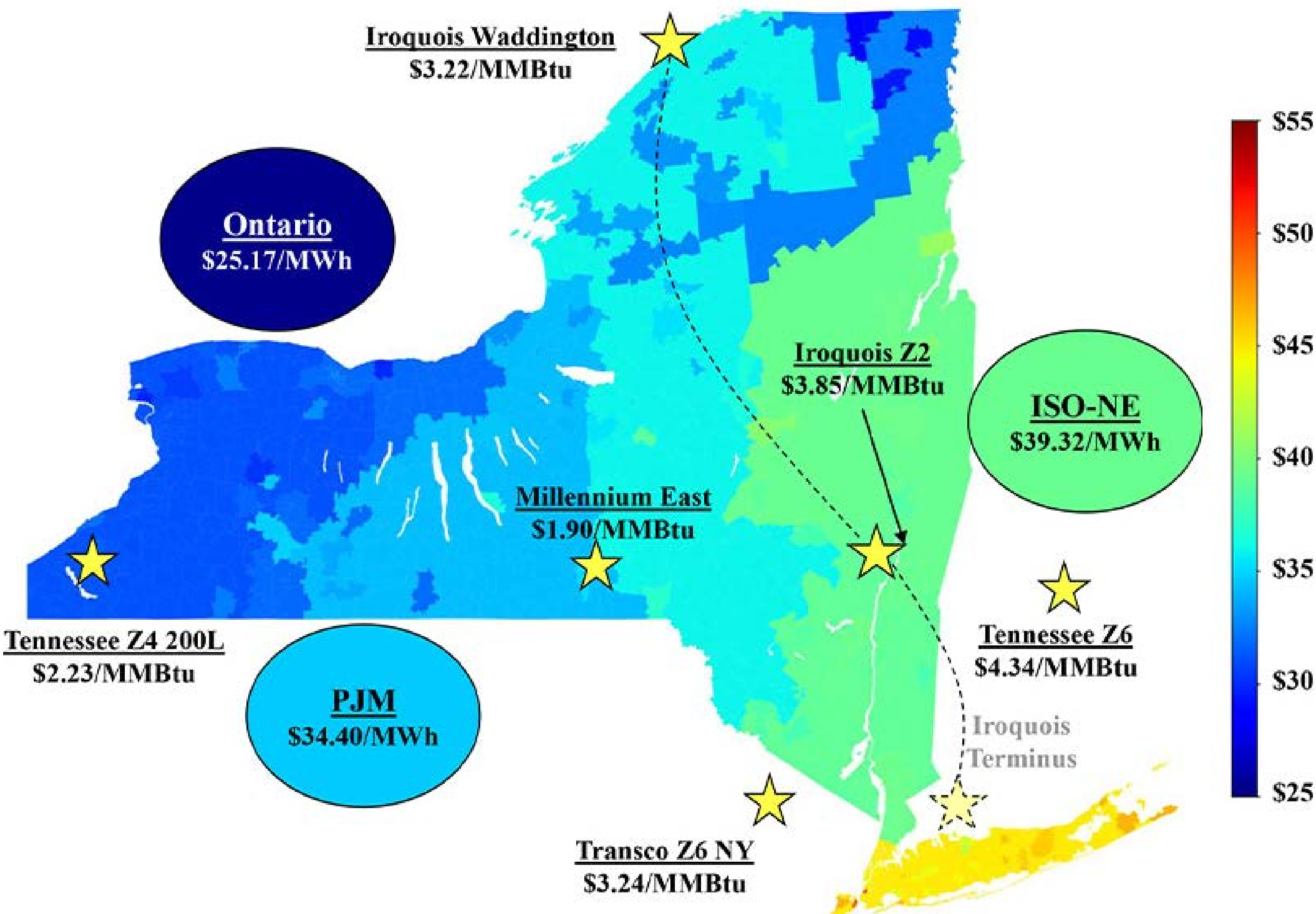
Across the state, gas prices fell between 8 and 29% compared to a year ago because of the mild winter and continued growth in gas production. But the city was left behind in this trend and saw a 10% increase.

"The last two winters had much lower gas prices than in the previous winter. … That's virtually true everywhere," said MMU's Pallas LeeVanSchaick.

New York City's experienced modest increases in energy prices driven by congestion from transmission outages, while NYISO day-ahead congestion revenues fell 47%. The completion of several transmission projects increased transfer capacity over the Central-East and UPNY-SENY interfaces.

"Congestion revenue shortfalls during the quarter were pretty small," said LeeVanSchaick. "They're way down from the previous couple years because the amount of outages was really reduced quite a bit."

The city also accounted for a higher level of congestion this quarter, most of which occurred during a period of low temperatures in January that coincided with the outage of a transmission line, reducing the import capability. That outage alone led to $5 million in congestion shortfalls during the cold snap. ■



| Potomac Economics

NYISO News

NYISO Stakeholders Question Draft CEII Protection Requirements

By Vincent Gabrielle

| Shutterstock

The NYISO Transmission Planning Advisory Subcommittee on July 9 criticized an ISO proposal to include Critical Energy/Electricity Infrastructure Information (CEII) protection requirements in manual *updates* over what they described as confusing wording and inconsistent requirements.

The ISO is concerned that with the "explosion" of generator interconnection requests, there is a gap in the CEII protection requirements.

"There are FERC CEII protection rules, but they apply to information submitted to or generated by FERC; protections do not apply to information exchanged at the ISO level," said William Derasmo, a partner at Troutman Pepper who presented the updates on behalf of NYISO. "The idea is to try to put something in place to fill that gap."

Derasmo explained that the updates would be followed by conforming tariff revisions. He cited a *warning* from the FBI that renewable energy generation could pose additional cybersecurity risks. (See *FBI Warns Power Sector of IBR Cyber Vulnerabilities*.)

"This topic is not going away," Derasmo said. "It's a problem that is here, and we can't wish it away."

The proposed revisions would require developers of generation or transmission facilities, their consultants or any nongovernmental organizations requesting CEII from NYISO to:

- provide NYISO and the transmission owner with a list of any countries outside the U.S. and Canada in which they operate;
- obtain cybersecurity risk insurance in coverage amounts of $5 million;
- establish a chain of custody, policies and process to securely handle and store CEII;
- not engage with entities owned by, controlled by or subject to the jurisdiction of "foreign adversaries";
- engage in background screenings and security training for personnel accessing CEII;
- provide for secure deletion of CEII from systems; and
- report cybersecurity incidents to the NYISO and the TO within 48 hours.

Stakeholders seemed confused that the draft updates used multiple overlapping definitions for "critical energy infrastructure," "critical electricity infrastructure" and "critical infrastructure." One stakeholder called it "overkill and unnecessary."

"We don't need to parse it between 'critical electric infrastructure' and 'critical infrastructure,'" they said. "You're adding an unnecessary complication."

Others expressed confusion that the manual updates were being proposed without the accompanying tariff revisions. Typically tariff revisions are approved by FERC first before manual updates to define the scope of revision.

"I guess I'm really struggling with how to do it this way," the stakeholder said. "I think you're maybe unnecessarily causing some confusion, if not complication, here. In any event, we're not going to have any helpful guidance until you're proposing the tariff first."

Others did not think the draft as written covered every person or entity NYISO intended to target with the requirements. One stakeholder asked why the rule was written for developers and not any market participant with access to CEII.

"Our intention with ... the set of security requirements is that we would apply this to all recipients of CEII who go through our CEII request process," said Chris Sharp, NYISO senior compliance attorney.

"OK, but it should be written that way," the stakeholder replied.

One stakeholder raised the issue of "special treatment" of the TOs. The current draft of the rules would require that recipients of CEII inform NYISO and TOs of security incidents and foreign business dealings, but they would not require the ISO or TO to inform recipients of cybersecurity breaches or similar multinational dealings.

Another stakeholder raised the point that some people who have access to CEII do not represent or work for multinational corporations with large budgets. Requiring $5 million in cybersecurity risk insurance would likely deny people and firms of this kind access to CEII. They suggested having a MyNYISO account would be enough to trigger the insurance requirement. ■

PJM News

Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC

By James Downing

Talen Energy's deal to carve out capacity from its Susquehanna Nuclear Plant to serve a growing data center on its site drew protests at FERC from other parties who argued the deal and others like it could shift costs and threaten reliability (*ER24-2172*).

Talen developed the data center on its own, which is next to the Susquehanna plant in northeastern Pennsylvania, and this year sold it to Amazon Web Services. PJM filed an amendment to an existing interconnection service agreement (ISA) so it could expand the data center's power from 300 MW to 480 MW, while the nuclear plant produces 2,520 MW between two reactors. Eventually, the data center could grow to 960 MW.

The deal included operating provisions that are meant to preserve reliability, all of which were agreed to by the nuclear plant, PPL (the local utility) and PJM, Talen subsidiary Susquehanna Nuclear told FERC.

The debate kicked off with a protest Exelon and American Electric Power filed last month, arguing that the application to change the ISA brings up too many novel issues and should be set for hearings.

"Absent further factual development, the commission will be unable to make an informed decision, and parties will be denied due process," the two utilities said.

AEP and Exelon argued that the ISA represents "an end-run around the PJM stakeholder process" and would create new categories of load and alter the fundamentals of the RTO's market design. While the two claimed the deal itself would lead to $140 million per year in cost shifts to other consumers, they argued the real risk is that it will be replicated many times over.

"Should large quantities of load rush to co-locate with generation on terms that bear even a resemblance to the ISA at issue here, PJM capacity markets will have steadily decreasing volume as the capacity resources flee to serve load that uses and benefits from — but does not pay for — the transmission system and the ancillary services that keep the system running," AEP and Exelon said.

Building generation and transmission to replace that lost capacity will take years, and in the meantime, a tighter supply-and-demand balance will result in "rising energy and capacity prices" and make it harder to address resource adequacy, they added.

Talen Energy's Susquehanna Nuclear Power Station | *Jakec, CC BY-SA 4.0, via Wikimedia Commons*

Their protest drew rebukes from Talen, Amazon, Constellation Energy and Vistra. Both Constellation and Vistra, which filed a reply jointly, own large generation fleets with major competitive retail power businesses. Constellation was spun off from Exelon in 2022.

Data centers are being driven by advances in artificial intelligence, which the White House, state governments in PJM and others see as a huge economic opportunity, Constellation and Vistra said in their filing July 10.

"The corresponding technological advancement is critical to America's competitiveness and our national security and thus building out our digital infrastructure has been a focus at both the federal and state levels," they added.

They said the proceeding in question is limited, and FERC has a straightforward task: assessing the ISA updates needed to facilitate interconnection of the expanding data center. The protest from AEP and Exelon throws unrelated spaghetti on the wall to see what might stick, the companies said.

"It is yet another attempt by AEP and Exelon to deter or outright prevent the development of new data centers, particularly co-located, behind-the-meter data centers," Constellation and Vistra said. "The protest spotlights AEP and Exelon's efforts to erect roadblocks to PJM generators serving co-located load, which would leave utilities as the only option for meeting the robust demand for data center infrastructure in the region."

The behind-the-meter configuration of the Susquehanna deal means the data center is not leaning on the grid at all, and if anything, it saves some money on the transmission upgrades that meeting such large demand would otherwise require, they said.

If FERC has concerns about the issue of data centers connecting directly to generators, then it should require PJM to restart its stakeholder process on the issue but limit that to 90 days to "expeditiously accommodate these types of innovative, behind-the-meter arrangements in light of the nation's urgent data infrastructure needs," Constellation and Vistra said.

Susquehanna told FERC the updated ISA is supported by PJM studies that show no reliability impacts from increasing the co-located load from 300 MW to 480 MW. It noted that FERC already approved the initial 300 MW. The filing is a routine document that FERC regularly approves, the firm said.

"Susquehanna Nuclear did not hoodwink PJM

PJM News

and PPL," the firm said. "The parties to this interconnection agreement, being fully aware of the configuration, the facts and the current operations for this co-located load, simply do not share AEP/Exelon's concerns."

PJM and Monitor Responses

PJM filed a response to AEP and Exelon urging FERC to approve the ISA, but it added that that does not foreclose it from looking at new rules on co-locating large demands with power plants. The RTO ran a stakeholder process on that subject in 2022 and 2023, but it did not lead to any rule changes.

"Depending upon the outcome of any such process, other ISA revisions may be necessary," PJM said. "But those are separate matters for another day in another docket and should be viewed as outside the scope of this narrow proceeding about a single amended service agreement. Any open policy issues do not change the fact that, today, Susquehanna is indirectly supplying power to a co-located load arrangement."

While Talen and other major retailers want FERC to avoid upsetting the applecart on a growing source of demand for their services, other parties agreed with the two utilities that the issue warrants a deeper look.

PJM's Independent Market Monitor seconded AEP and Exelon's protest, saying the amended ISA brings up significant issues that go well beyond one contract.

"It is well understood that this ISA will be precedential and will lead to similar arrangements at many other PJM nuclear plant sites and potentially other generator sites," the Monitor said. "PJM needs to provide a comprehensive analysis of the impact of removing significant levels of generation from the market."

The policy decisions embedded in the ISA that cover how backup power is handled, and other issues, differ greatly from positions PJM previously took in the stakeholder process, the IMM added.

Talen could have sold output from the plant to the data center over the transmission system, but the co-location approach avoids transmission and distribution charges, as well as being directly subjected to the rate regulation of states and FERC, the Monitor said.

It also argued that if other nuclear plants in PJM started offering similar services to large customers, it would lead to higher costs and emissions, eventually undermining reliability and the RTO's markets.

"Power flows on the grid that was built in significant part to deliver low-cost nuclear energy to load would change significantly," the IMM said.

The Pennsylvania Public Utility Commission posted a short intervention, but it agreed with the calls for FERC to take a deeper look at the issue.

The Natural Resources Defense Fund weighed in with a *blog* arguing that while the data center would get carbon-free power, it will lead to higher demand for natural gas generation to serve other nearby demand and that will lead to higher emissions.

Other nuclear plants are considering similar deals, with NRDC pointing to Dominion Energy's Millstone plant in Connecticut, Public Service Enterprise Group's nuclear plants in New Jersey and even the previously retired Palisades plant in Michigan. ■

PJM Hears Proposals to Redesign EE Participation in Capacity Market

Complaints over EE Market Participants at FERC Grow to 3

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM stakeholders presented several proposals to revise how energy efficiency resources are measured and verified to the Market Implementation Committee during its July 10 meeting as the number of complaints filed at FERC against the RTO's handling of EE market participants has grown to three.

Affirmed Energy argued that while the focus on measurement and verification (M&V) has dominated the stakeholder process on EE, it is secondary to the root issue of the addback: a process in which EE that clears in a Base Residual Auction (BRA) is removed by the supply stack and an equal amount of megawatts are added to the load forecast.

Affirmed's Luke Fishback said the company's *proposal* would aim to improve PJM's load forecast using data from the Energy Information Administration's National Energy Modeling System (NEMS) and only allow EE that is not captured by the forecast to participate in the capacity market. Once there is no overlap between the load forecast and market-participating EE, he said the addback could be removed and EE resources could act as reliability resources with the ability to displace other capacity offers.

The addback is the subject of a complaint that the consumer advocates for New Jersey, Maryland and Illinois filed against PJM last month, arguing that it improperly prevents EE from acting as a reliability resource and is a substantial change that should have been codified in the RTO's governing documents and approved by the commission prior to implementation (*EL24-118*). (See *PJM Consumer Advocates File Complaint on EE Market Design*.)

Given the complaints pending over the addback, Fishback argued that any changes to PJM's M&V rules would likely be disrupted by commission orders requiring changes to the EE market design. Moving forward prior to the resolution of those complaints and a reworking of the addback would be "putting the cart before the horse," he said.

Affirmed itself filed a complaint against PJM on July 5, arguing that the RTO is improperly withholding collateral that the company posted for the 2023/24 delivery year even after approving the company's capacity offer, approving its post-installation M&V report and the conclusion of that delivery year (*ER24-124*).

Peter Langbein, PJM | *© RTO Insider LLC*

The complaint states that PJM is withholding the collateral because of an investigation FERC's Office of Enforcement initiated in 2021. The company wrote that it has begun laying off employees and, without the return of the funds, could be "forced out of business."

The Independent Market Monitor also filed a complaint against Affirmed and several other EE providers in May alleging that they had not met the BRA's M&V requirements and should not be paid for the claimed EE megawatts in the 2024/25 delivery year (*EL24-113*). (See *Monitor Alleges EE Resources Ineligible to Participate in PJM Capacity Market*.)

PJM: Require Sole Causal Link Between Capacity Market and EE Installations

PJM presented to the committee its own *proposal*, which would tighten the participation requirements for EE resources to only allow those that can demonstrate that capacity market revenues were the only deciding factor in them materializing.

PJM's Pete Langbein said participation should be contingent on auction revenues causing a corresponding decrease in load. "People need to do something to get paid," he said.

Midstream and upstream programs, which work with manufacturers and retailers to stock shelves with more efficient devices, would be required to validate that participating appliances were installed and in use within the locational deliverability area in which the capacity is participating. End-use customer data would be required upon PJM request for all installations.

The period for which EE could participate in the capacity market after the installation would be shortened from four years to one, and EE would no longer be permitted to be included in fixed resource requirement (FRR) plans. FRR entities would instead be required to offer EE into the BRA.

PJM proposed a timeline of endorsement in August, a FERC filing the following month and an order in November. Langbein noted that the deadline for post-installation measurement and verification (PIMV) reports is in November, but the aim is to have an order before the 2026/27 BRA scheduled to be conducted in December.

PJM News

CPower's Aaron Breidenbaugh said the 100% causation requirement is the most problematic component of PJM's proposal and would set the bar so high that none would be able to reach it.

Fishback challenged PJM's causation principle by noting that generators are built with the expectation of revenues beyond the capacity market. He said it would effectively eliminate EE participation in PJM's market.

CPower Proposes Standardization of M&V, Separate Issue Charge on Addback

CPower *proposed* creating a process for reviewing M&V methodologies proposed by EE participants, potentially including retaining a third party evaluator. Unlike PJM's proposal, it would not include any time limit on the validity of using state technical reference manuals (TRM) in M&V plans.

A tracking system for registering EE installations would be established to ensure that no projects are being double counted between EE providers, which Breidenbaugh said would be akin to the demand response registration process. The physical location of EE installations would be required to be identified to at least the electric distributor company.

Breidenbaugh said the proposal is designed to create a more standardized process for M&V, including by requiring nonproprietary methodologies to be made public.

The proposal also includes a problem statement and issue charge focused on revising the addback and EE forecast model, which Breidenbaugh said is meant to "divorce the issues associated with measurement and verification from some of the more contentious issues."

Paul Sotkiewicz, president of E-cubed Policy Associates, said the M&V of EE offers stands apart from other resource classes because they are not required to be metered, potentially creating a discriminatory discrepancy compared to generating resources. He questioned whether M&V based on a TRM or external study meets PJM's sample size requirements, and how EE providers and PJM check and verify the accuracy of those data.

Breidenbaugh said it's difficult to compare the metering requirements of a large-scale power plant, where the cost of a meter is relatively small compared to the overall facility cost, with the nature of EE projects that could be as small as upgrading light bulbs.

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

Monitor Would Eliminate EE Capacity Market Participation

The Monitor *presented* a proposal that would remove EE from the capacity market construct outright on the basis that EE has been included in PJM's load forecast since the 2016/17 delivery year.

"The tariff states unambiguously that EE is not a capacity resource when EE is incorporated in the load forecast used for the capacity market," Monitor Joe Bowring told *RTO Insider*. "As a result, PJM recognized for the 2016/17 delivery year that EE was not a capacity resource and stopped including EE in the capacity market at that time, as they were required to do. But PJM decided to pay EE resources a side payment, or uplift, regardless. The Market Monitor's proposal is to end that side payment, which is not provided for in the tariff."

Bowring said consumers are overpaying for a resource that is not a capacity resource and therefore provides no reliability benefits, and there is not evidence that the uplift payments are resulting in changes in consumer behavior. Rather than being compensated through the capacity market construct, he said EE is compensated as a result of the reduced energy and capacity costs to participants. He said it is a double-counting issue that has been recognized by PJM and FERC since the introduction of EE in the RTO's markets.

"What we're calling EE in the PJM world should not be paid through the capacity construct. It is, as a factual and tariff matter, not a capacity resource," he said.

Breidenbaugh said it has not been demonstrated that a majority or the entirety of EE is captured in the load forecast.

"There is a question about how much of this market energy efficiency is included in the forecast and what is not, and I would hope we would agree ... that energy efficiency which is not a part of the forecast should not be subject to the addback," he said.

Exelon Seeks Protection for State EE Programs

Exelon's *proposal* merges components of the CPower and PJM proposals, including the EE registration tracker from CPower and a PJM component that would remove EE from the Capacity Performance construct, exempting EE from performance assessment interval (PAI) penalties and overperformance bonus payments.

It would also include language that state-authorized EE programs would be *de facto* qualified to participate in the capacity market, with the state's legal authority held as the evidence of their validity.

Exelon's Alex Stern said that PJM approval of the original M&V plan should codify the proposed methodology that the market participant intends to use to support its capacity offer, and that approval of the PIMV report should hinge on whether that methodology was followed. Exelon also proposed to rectify a perceived flaw in PJM's proposal that would potentially put EE providers in a penalty situation by being unable to rely on the M&V report while then also being unable to fix an after-the-fact identified problem through an Incremental Auction.

"Market participants need to be able to rely on M&V reports," Stern said. "It is fundamental to fair EE market participation."

Stern said all but CPower's proposal would impinge on the ability for state-directed EE programs to participate in the capacity market. He encouraged PJM and the Monitor to engage with states to ensure they are educated on the potential impacts to those programs.

"I still strongly, strongly encourage PJM and the IMM to continue outreach to the states on this effort, but for now we wanted to try to put in a package that preserves and respects the ability for state programs to" continue participating in the market, he said. "As long as the states want the programs in the PJM capacity market, we think the rigor and regulatory scrutiny that characterizes those programs and differentiates them from other market participants should be respected in the PJM market construct." ■

Dominion Issues RFP for Small Modular Reactor at North Anna

By James Downing

Virginia Gov. Glenn Youngkin (R) addresses the crowd during Dominion's announcement at the North Anna nuclear plant on July 10. | *Dominion Energy*

Dominion Energy Virginia issued a request for proposals from developers to build a small modular reactor at its existing North Anna nuclear plant in Louisa County, Va., the company announced July 10.

The utility is not yet committing to building an SMR at the plant northwest of Richmond, Va., but the RFP represents a first step to evaluating the technology's feasibility.

"For over 50 years, nuclear power has been the most reliable workhorse of Virginia's electric fleet, generating 40% of our power and with zero carbon emissions," Dominion Energy CEO Robert Blue said in a statement. "As Virginia's need for reliable and clean power grows, SMRs could play a pivotal role in an 'all-of-the-above' approach to our energy future. Along with offshore wind, solar and battery storage, SMRs have the potential to be an important part of Virginia's growing clean energy mix."

The announcement was made possible by Senate Bill 454, which was enacted into law earlier this year and allows Dominion and American Electric Power's Appalachian Power to recover the costs of developing one or more SMRs that do not exceed 500 MW.

As part of the process, Dominion could ask the State Corporation Commission for separate approvals for different development phases of the project. The company expects to file for cost recovery this fall.

The legislation caps any rate increase from developing an SMR at $1.40 per average monthly bill, but the utility said its cost recovery request should come in well below that.

Dominion announced the RFP during a press conference at the North Anna plant that included Virginia Gov. Glenn Youngkin and other state officials.

"The commonwealth's potential to unleash and foster a rich energy economy is limitless," Youngkin said. "To meet the power demands of the future, it is imperative we continue to explore emerging technologies that will provide Virginians access to the reliable, affordable and clean energy they deserve. In alignment with our all-American, all-of-the-above energy plan, small nuclear reactors will play a critical role in harnessing this potential and positioning Virginia to be a leading nuclear innovation hub."

Dominion has been using nuclear power for decades, with the two-reactor North Anna plant producing 17% of Virginia's power and its Surry Power Station, near the state's southeastern coast, producing another 14%. The company also runs nuclear plants in Connecticut and South Carolina.

North Anna has pending applications to extend its reactors' commercial lifespan out to 2058 and 2060, while the SMR facility could come online in the 2030s and help the firm produce firm, carbon-free power to meet Virginia's net-zero-emission goals.

The legislation caps SMRs at 500 MW, which is less than one-third the capacity of North Anna and Surry. SMRs are produced in a factory and then assembled on-site, a process that is meant to be more efficient than the one-off constructions used in traditional nuclear plants.

Dominion said Virginia has an ample workforce to deal with SMRs because of its existing power plants and the fact that it is home to one of two shipyards in the country that can make nuclear-powered ships. Virginia already has about 100,000 jobs that are directly tied to the nuclear industry.

Siting an SMR alongside North Anna means Dominion already owns the land and would be able to take advantage of the interconnection facilities there. The utility said it was considering "sites across Virginia" for additional SMRs. ■

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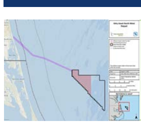
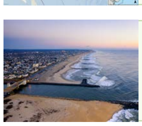


Dominion to Buy Kitty Hawk North Offshore Wind Lease

NetZero Insider



3 OSW Proposals Submitted to NJ

NetZero Insider

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

PJM OC Briefs

Indian River Transmission Upgrades Projected to be Complete One Year Ahead of Schedule

VALLEY FORGE, Pa. — PJM's Chris Pilong informed the Operating Committee that the transmission upgrades needed to allow the retirement of Indian River Unit 4 could be complete by the end the year, potentially allowing the reliability-must-run agreement with the generator to be terminated a year early.

Pilong said rebuilding of the 138-kV Vienna-Nelson line is ahead of schedule and would resolve the transmission violations that led to the RMR contract negotiations with NRG energy to keep Unit 4 in operation. While the RMR is in effect, the Maryland Office of People's Counsel and the Independent Market Monitor have protested the compensation included in the contract, which amounts to $263 million between June 2022 and the original RMR end date of Dec. 31, 2026. (See *PJM Monitor and Consumers Protest Indian River Compensation Settlement.*)

The line rebuilding constituted the largest component of the upgrades PJM identified, with the remainder being substation upgrades that are expected to be completed ahead of the line coming back into service. Pilong said the rebuilding of Vienna-Nelson was complicated by the line needing to be in service during the summer, which limited when it could be taken out of service.

The RMR contract includes a 65-day notification requirement before the agreement can be terminated.

NRG's Indian River Generating Station in Delaware | *NRG*

Stakeholders Endorse Revisions to Manual 12 for Black Start Fuel Requirements

The committee endorsed by acclamation *revisions* to Manual 12: Balancing Operations to include items approved in the package matrix stakeholders approved in 2022, but which were inadvertently not reflected in the corresponding manual revisions. (See *Stakeholders Endorse PJM's Black Start Fuel Reqs Proposal.*)

The overall proposal stakeholders endorsed established a new category of "fuel-assured" generators and required at least one such unit to be committed in each transmission zone. The criteria to qualify as a fuel-assured unit vary based on resource type, including connections to multiple interstate gas pipelines, onsite fuel storage and dual-fuel capability. (See "PJM Presents Black Start Manual Revisions," *PJM OC Briefs: June 6, 2024.*)

The latest changes include exempting fuel-assured generators from penalties for going under their minimum fuel inventory while responding to a performance assessment interval (PAI) or if the storage was emptied for regulatory inspections. The revisions also remove an existing six-month fuel assurance inventory notification requirement and replace it with language that generators must verify their fuel and consumables inventory upon PJM request and an annual verification requirement on the black start test form.

Security Update

PJM Director of Enterprise Information Security Jim Gluck said the FBI has published a public interest notification for renewable energy developers because of attackers targeting the sector, possibly because of the interest and growth in clean energy.

Recent attacks against automotive dealers have involved impersonations of customer support staff to gain access to sensitive data that was stolen, which Gluck said underscores the need to be cautious when interacting with third parties.

The Cybersecurity and Infrastructure Security Agency (CISA) has *published* new network access security guidelines around protecting networks from intrusion and how to ensure users are interacting with external networks safely.

June Operating Metrics

Interactions between a heat wave with some of the highest peak loads of any June that PJM has experienced and thunderstorms led to high peak load forecast error between June 22 and 25, culminating with actual load being about 7.5% higher on June 25 than the day-ahead forecast.

PJM's Marcus Smith *said* the heat wave subsided faster than expected June 25, causing some regions to see temperatures significantly below forecast. The peak and hourly error was above the 25-month average but fell well below the error rates seen in June 2023 and 2022, he said.

The month saw three shared reserve events, two spin events, seven hot weather alerts and one geomagnetic disturbance warning. Three shortage cases were approved June 3 because of a unit tripping. ■

— Devin Leith-Yessian

PJM News

PJM PC/TEAC Briefs

Planning Committee

Elevate Reviews CIR Transfer Proposal

Elevate Renewables *presented* a first read on one of six *proposals* to revise how capacity interconnection rights (CIRs) can be transferred from a deactivating generator to a replacement resource interconnecting at the same site. (See "Stakeholders Endorse Revisions to CIR Transfer Issue Charge," *PJM PC/TEAC Briefs: June 4, 2024*.)

The package would create a fast-track process for replacement resources to use to go through the interconnection process, provided they would have an equal or smaller output and CIR value as the deactivating retiring resource and no material adverse impacts to the grid are identified. Replacement resources would be required to interconnect at the same substation and voltage as the original resource, although use of a different breaker would be permitted.

Elevate envisions a nine-month time frame for most projects to get through the expedited process, with 60 days for initial application review, 180 days for a replacement impact study looking at any potential transmission violations, and 30 days for the interconnection service agreement (ISA) to be approved.

Projects would be allowed to continue through the generation replacement process if minor network upgrades are identified. A 90-day facilities study process may be required before the interconnection agreement can be offered.

Elevate's Kun Zhu said resolving localized voltage issues would likely be seen as a minor impact, while violations requiring upgrading a line to a higher rating would require projects to shift to the full interconnection process.

The ability for projects to go forward with minor network upgrades stands in contrast to PJM's proposal, which would require the replacement resource to go through the standard interconnection process if any upgrades are identified or if available transmission headroom is changed by the addition of the resource.

Proposals have also been sponsored by Gabel Associates, PowerTransitions, MN8 Energy and the Independent Market Monitor.

The Elevate package would also permit standalone battery storage to be eligible for the generation replacement process, unlike PJM's design. A companion study of the charging phase or separate load study would be conducted to identify any needs prompted by the charging phase. Zhu said the generation interconnection study process was designed solely for resources that would only inject energy into the grid, making the charging phase irrelevant to the CIR transfer eligibility discussion.

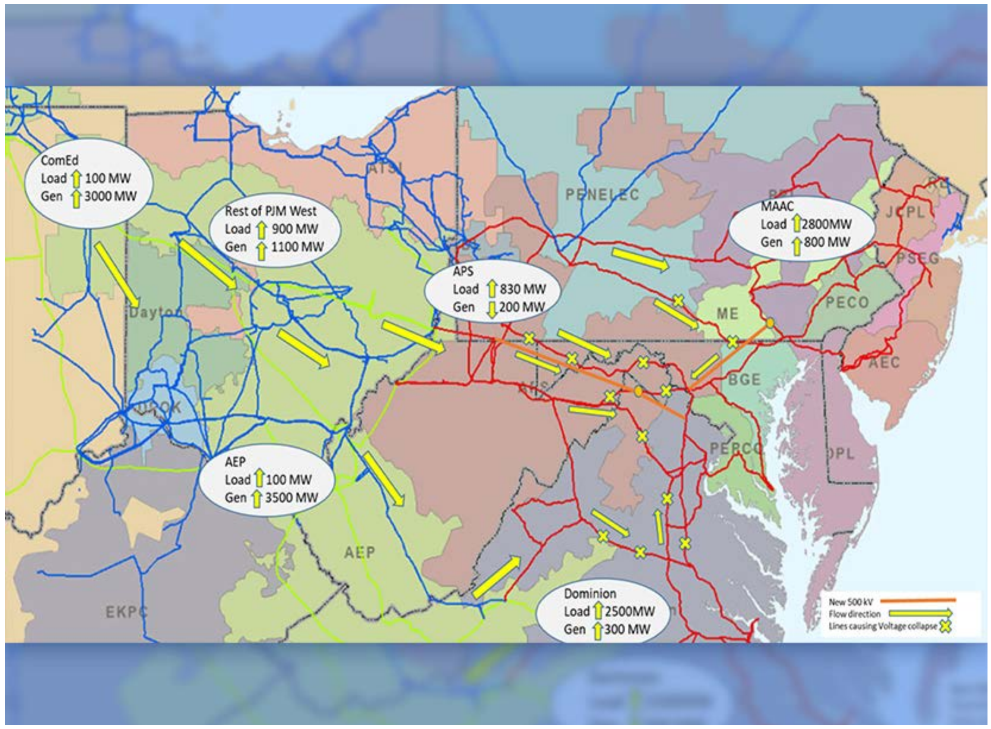
PJM's Ed Franks said standalone storage is not permitted in the RTO's proposal because that resource would not have been envisioned in the original network upgrade studies done on the retiring resource and the charging phase would conflict with PJM's requirement that replacement resources have no grid impacts, such as changing line loading. Hybrid resources with a storage component would only be allowed if the battery could not charge off the grid.

Elevate's Tonja Wicks said PJM has been messaging that new entry isn't set to keep pace with deactivations and accelerating load growth, driving the need for process to quickly replace retiring generators with new resources. She also noted that only a small subset of projects that have cleared PJM's interconnection queue in recent years have entered commercial operation, an issue she argued could be helped by focusing on proposals that can be quickly studied and are likely to be assigned minimal network upgrades.

"We need new approaches to address this new problem that we're seeing as we deploy new technologies," she said. "We didn't have reserve deficits 10 years ago."

Ken Foladare, of the Tangibl Group, said it's likely to be well into 2025 before the proposal would be implemented if approved by stakeholders and FERC, putting it close to the targeted full rollout of PJM's new cluster-based interconnection process. He questioned the benefit of the proposal if it is likely to go into effect around the same time that PJM is completing a process to speed interconnection for all resources.

Wicks said the Elevate package would establish a nine-month study process that would remain quicker than the two years she said it would likely take resources to typically clear PJM's new approach. Not only would that allow some resources to receive ISAs faster, she said, but it would resolve a timing misalignment between when resources deactivate and when their CIRs can be passed on to a new resource.



A PJM map shows the differences between forecast load growth and added generation between the 2028 and 2029 models. | *PJM*

PJM News

PJM Proposes Load Analysis Subcommittee Charter Revisions

PJM presented *revisions* to the Load Analysis Subcommittee (LAS) charter that would shift its focus from collecting and presenting forecast data provided by transmission owners to reviewing the independent forecasts the RTO produces and its methodology.

Much of the status quo charter *language* focuses on collecting load data and developing forecasts, which PJM's Molly Mooney said is a legacy of when TOs would submit their own forecasts to the LAS. The revisions instead focus on review of the end product forecasts and the data used to construct them.

"It's definitely time to review and update our charter. The charter is also a legacy of when the Load Analysis Subcommittee members provided load forecasts to PJM and we gathered those materials and processed them ... now PJM does an independent load forecast, so the role of the LAS has changed a little bit," Mooney said.

Data Centers Challenge Light Load Forecast Case

PJM's Stan Sliwa presented *revisions* to the light load case inputs used in the Region Transmission Planning Process (RTEP) load forecast, which aim to reflect the growth of load with flat profiles unaffected by weather and season. The typical example of such load, Sliwa said, is data centers that tend to consume a consistent amount of power throughout the year.

The light load case is designed to create an accurate representation of shoulder periods by scaling load down to 50% of the summer forecast peak using bus-level data provided by transmission owners. The proposal would limit that practice to not include any non-scalable load reported by TOs.

The Manual 14B changes also expand the NERC TPL standards examined during generator deliverability analysis to match current practice, updating the system operating limit (SOL) definition and adding new standards created by NERC.

Transmission Expansion Advisory Committee

3 TOs Negotiate Changes to Component Project in 2022 RTEP Window 3

NextEra Energy, FirstEnergy and Dominion Energy have *redesigned* the plans for a new 500-kV line between the 502 Junction substation and the new Aspen facility to reduce greenfield development and improve constructability. The project is a component of the $5 billion transmission upgrade package aimed at resolving reliability violations identified throughout Maryland and Virginia. (See *FERC Approves Cost Allocation for $5 Billion in PJM Transmission Expansion*.)

The proposed changes would replace a NextEra segment of the construction, which follows a greenfield route to the west of the existing 500-kV Doubs-Goose Creek line, with a design to continue the lines farther east towards the Doubs substation. Bypassing Doubs, the line would follow the existing corridor south through the Dickerson H substation and to the Goose Creek substation, where it would terminate, instead of at Aspen.

The reworked design would split the former NextEra component, which would cost $71.2 million, between FirstEnergy and Dominion, increasing the total cost by $167.5 million. NextEra would retain other components of the overall project amounting to $440.9 million, including building a new Woodside substation between the Black Oak and Doubs substations.

FirstEnergy would connect the line to the Doubs-Goose Creek corridor by rebuilding a 16-mile segment of the 138-kV Millville-Doubs line to be capable of supporting 500-kV overbuild. It would also be responsible for constructing an additional 15 miles south towards Goose Creek.

The Dominion portion of the work involves constructing the final 3 miles south into Goose Creek and installing a 500-kV capacitor bank originally destined for that facility to the Aspen substation.

Ratepayers along the revised corridors questioned the decision-making process for choosing which route would be selected and argued the change was shifting the impact from a wealthier area along the NextEra pathway to a different community.

PJM's Jason Connell said the RTO is focused on arriving at the most optimal engineering solution.

Reliability Analysis Shows Growing Need for West-to-East Transfer Capability

Analysis of shifting load and generation patterns between 2028 and 2029 RTEP models find that rapidly growing load in PJM's eastern regions could result in increased power flows from the west, where sizeable solar and wind development is expected to occur.

The MAAC region is forecast to see around 2,800 MW of load growth and 800 MW of new generation between the 2028 and 2029 summers, while the Dominion zone should see 2,500 MW in new load and 300 MW of added generation. While adequate generation growth is expected in the ComEd, AEP and Rest of PJM West zones to cover the load in the east, the analysis identified several voltage collapse violations in the summer across southern Pennsylvania, Maryland and Virginia.

PJM's Jeff Goldberg said the analysis shows that the need for additional transmission linking the east and west is likely to present sooner than expected.

PJM Director of Transmission Planning Sami Abdulsalam said the analysis is meant to identify future needs and does not include any proposed solutions, adding that any transmission proposals are not bound to follow similar designs to past RTEP projects.

Supplemental Projects

Public Service Enterprise Group *presented* a $169 million project to construct a new 230/69/13-kV substation near Kenilworth, N.J., to address capacity overloads identified at its Springfield Road and Aldene substations. The new facility would be cut into the existing 230-kV Springfield Road-Aldene line and the 69-kV Springfield Road-Roselle line with a projected in-service date in December 2029.

Dominion *presented* a $42 million project to construct a new substation to serve a data center complex in Bristow, Va., which is projected to consume over 100 MW by 2029. The proposed Devlin facility would cut into the existing 230-kV Dawkins Branch-Vint Hill line and host nine 230-kV breakers configured as a breaker-and-a-half. The project is in the engineering phase and is targeted to come online in June 2026.

The utility presented a $30 million proposal to construct a substation to serve another data center in Mecklenburg County, Va., which is forecast to add 110 MW of load by 2028. The 230-kV Allen Creek switching station would cut into the 230-kV Finneywood-Cloud line. The design is in the conceptual phase with a projected in-service date of Dec. 30, 2025.

Dominion also *said* that around a dozen new substations will be needed across Virginia to serve data center growth, with most of the new load concentrated in Northern Virginia, including Prince William, Henrico and Charles City counties. The loads are expected to come online between December 2026 and the end of 2028. ■

— Devin Leith-Yessian

PJM News

PJM MIC Briefs

Stakeholders Approve Changes to Quadrennial Review Financial Parameters

PJM's Market Implementation Committee endorsed by acclamation a PJM *proposal* to revise two financial inputs to the quadrennial review to reflect changing market conditions, particularly increased interest rates. The most recent review was approved by FERC in February 2022. (See *FERC Approves PJM Quadrennial Review.*)

The proposal would increase the after-tax weighted average cost of capital (ATWACC) from 8.85% to 10% and use a 0% bonus depreciation rate for the 2027/28 delivery year and beyond. The original quadrennial review included a 20% bonus depreciation value for the 2026/27 year. The proposal also updated the Bureau of Labor and Statistics (BLS) indices used in capital cost escalation rates.

The *changes* increase values for all five CONE areas by an average of $79/MW-day, with CONE Area 5 seeing the largest increase at $90/MW-day and Area 4 increasing by $65/MW-day. The proposal is slated to go before the Markets and Reliability Committee and Members Committee on Aug. 21, with a targeted filing date at FERC in August or September.

PJM's Skyler Marzewski said the automatic ATWACC adjustment was considered by staff and the Brattle Group — which was hired as a consultant for both the original quadrennial review and the re-evaluation of the financial parameters; however, it was determined that would provide minimal benefit, particularly if the review period is shortened to occur more often than every four years.

Paul Sotkiewicz, president of E-cubed Policy Associates, said the changes improve the accuracy of the values for the 2027/28 delivery year but that the net CONE for the previous year remains "unrealistically low," particularly since no merchant combined cycle generators have been financed in the past two years. The most recent quadrennial review included shifting the reference resource from a combustion turbine to a combined cycle unit.

Marzewski said PJM opted against reopening those values, since doing so would likely require altering the Base Residual Auction (BRA) schedule. Sotkiewicz responded that proper price formation with the right cost of capital shouldn't be sacrificed for timing and maintaining the auction timeline.

Skyler Marzewski, PJM| *© RTO Insider LLC*

PJM Presents Road Map of Market Design Changes

PJM *outlined* its expected timeline for several ongoing stakeholder processes and staff efforts to redesign several areas of the RTO's markets to address reliability issues identified in its *Ensuring a Reliable Energy Transition* analyses. PJM's February 2023 *4R's Report* was part of that analysis and laid out many of the reliability concerns the road map focuses on. (See "PJM White Paper Expounds Reliability Concerns," *PJM Board Initiates Fast-track Process to Address Reliability.*)

PJM Senior Director of Market Design Rebecca Carroll said the road map was created to track the various working areas and ensure that none fall through the cracks. It is meant to be a "living document" that will be updated as new efforts begin or are completed, she said.

Efforts already underway include the demand response performance window and accreditation, reserve performance and procurement during periods of operational uncertainty, load flexibility, regulation market signals and performance requirements, and FERC Order 841 requirements on electric storage market participation. The second phase of PJM's capacity market redesign is expected to begin in the second half of 2024 and continue through 2027.

The timelines on which work is expected to commence and be complete for each item are based on stakeholder issue charges, FERC filings and estimates from software programmers.

The rules around generators with co-located load were considered as an independent item of the road map but are currently included in the load flexibility category, Carroll said, adding that PJM is conducting a deeper investigation this year to look at what flexibility exists for data centers and large loads.

Executive Vice President of Market Services and Strategy Stu Bresler said corresponding road maps are being created for operations and planning, with the latter being reworked to reflect FERC's Order 1920.

Vistra's Erik Heinle said it's important that PJM views the road map as a living document that reflects the shifting priorities of stakeholders. He expressed surprise that the design of the market seller offer cap (MSOC) and possible over-mitigation of offers wasn't included in the document.

"When you look at what is driving certain retirements, certainly mitigation is one," Heinle said.

Carroll said changes to market mitigation are included in a FERC refiling PJM is preparing with several components of its Critical Issue Fast Path proposal the commission rejected in February (*ER24-98*). (See "PJM to Refile Portions of Rejected CIFP Proposal," *PJM MIC Briefs: June 5, 2024*.)

Independent Market Monitor Joe Bowring replied that there is no over-mitigation of market offers and defended the current design.

Several stakeholders expressed support for ranking the items by importance with respect to PJM's stated reliability concerns. Carroll said PJM thinks all the issues being discussed are high-priority and time-critical, but it is valid to consider the urgency of new issues that arise in the future.

Voltus Discusses DR Market Issues

Demand response provider Voltus *presented* several issues related to the accreditation of DR participation in the capacity market, known as load management, focusing on capacity offers being limited by winter energy availability and how PJM's effective load-carrying capability (ELCC) model determines availability.

Voltus Vice President of Energy Markets Emily Orvis said the company supports expanding the hours DR is available during the winter to match the growing reliability risks PJM has identified in the evening winter hours, which she said would allow DR providers to shift their customer enrollment to capture loads that match that time, rather than looking solely at their winter peak hourly consumption. The Markets and Reliability Committee in May endorsed an issue charge to consider modifying the availability of DR resources, while rejecting a quick-fix proposal to expand the winter availability window by two hours into the evening. (See "DR Availability Issue Charge Approved, Quick Fix Proposal Rejected," *PJM MRC Briefs: May 22, 2024*.)

She said PJM's practice of capping availability to the lesser of a facility's winter peak load or peak load contribution (PLC) limits the participation of winter-leaning customers who could provide higher curtailment during that season.

Additionally, some customers are able to reduce output to a greater degree than their winter peak load or PLC, but that additional capability is not included in the resource's accreditation. She said Voltus' energy availability in June 2024 was 25 to 30% higher than its accredited value.

Resources are also capped by an ELCC modeling approach that assumes that DR availability is proportional to system load, reducing the incentive for customers with flat load profiles to participate. Rather than looking to simulated system loads relative to peak forecasts, she said PJM's DR Hub holds more accurate information about the ability for a resource to reduce its output at a given hour.

The caps to DR availability create multiple de-rates to resource accreditation that do not align with the incentives for customers to participate in the capacity market in a way that reflects PJM's shifting view of when system risks are concentrated.

Bowring noted that he disagreed with each of the key points made by Voltus and requested an opportunity to provide education at a future meeting.

Manual Revisions Include ARR Trading Deadline

PJM's Emmy Messina *presented* several revisions to Manual 6, including administrative changes and adding a deadline for auction revenue right (ARR) trades. The changes were drafted through the document's periodic review.

Requiring ARR trades to be submitted by noon EP on the business day before the auction opens allows time for PJM to complete its necessary analysis. Relinquish requests would have a deadline of noon on the business day before the opening of stage 2 of the annual ARR allocation process.

The revisions would also disqualify transmission customers with firm services to charge energy storage or hybrid resources from receiving an allocation of ARRs. The language conforms with FERC orders in *ER19-469* and *ER22-1420*. (See *RTOs Move Closer to Full Order 841 Implementation*.) ■

— Devin Leith-Yessian

SPP News

SPP's Experience with Seams Could Help Markets+

RTO Shares its Expertise in Moving Power with Western Entities

By Tom Kleckner

SPP attempted to allay concerns about its ability to dispatch power among various Western regions during a July 11 webinar intended to illustrate its experience with seams management.

RTO staff discussed how they address seams issues in the Eastern Interconnection and how power is transacted and delivered between neighboring entities. It's part of SPP's effort to differentiate its Markets+ services offering from CAISO's Extended Day-Ahead Market (EDAM) as both organizations seek to sign up participants for their markets.

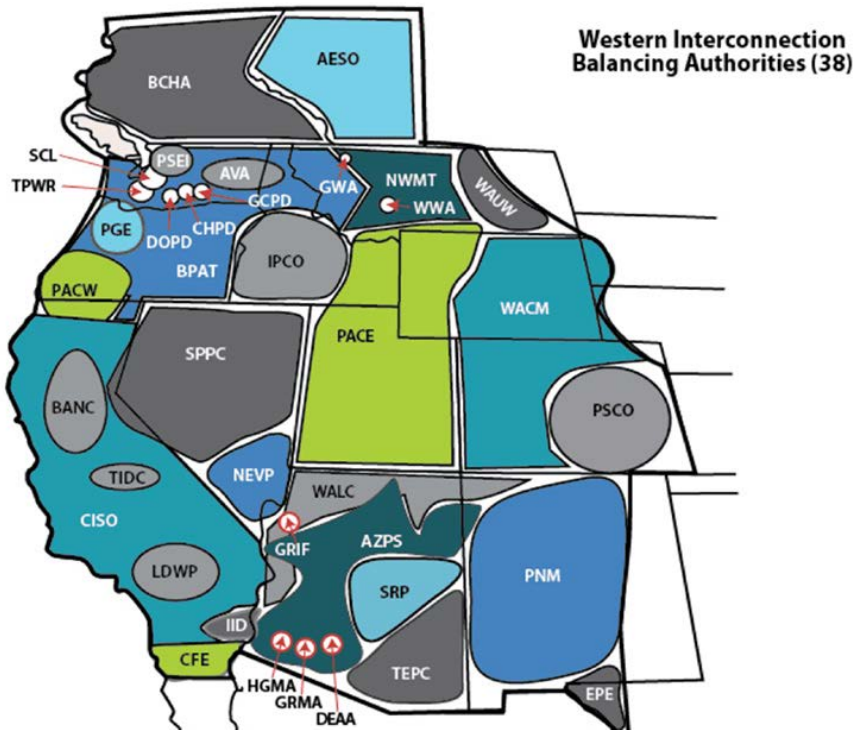
As Western Freedom Executive Director Kathleen Staks said last month during an Infocast conference in Arlington, Va., "We do not have an organized market ... we kind of have a mud-wrestling match going on right now."

SPP's outreach was a result of NV Energy's recent decision to join EDAM, despite the utility's participation in SPP's stakeholder-driven effort to set market rules and governance structures. The Nevada utility said EDAM's expected lineup "provides a significant degree of interconnectivity and supports a diversity of resources." (See *NV Energy Confirms Intent to Join CAISO's EDAM*.)

Antoine Lucas, SPP's vice president of markets, told *RTO Insider* that recent news articles and conversations about connectivity between Western markets following NV Energy's announcement pushed the grid operator to offer its perspective on seams issues and how Markets+ will dispatch service between the Pacific Northwest and Desert Southwest.

"We wanted to be able to provide a little bit of clarity around what we see and why we feel like the connectivity within the market pretty much remains unchanged," Lucas said. "I think intuitively, when people look at a map and just focus on geography, the state of Nevada is between the Pacific Northwest and Arizona and the rest of the Desert Southwest. But what really creates that ability to transfer in the market is the availability of firm point-to-point transmission rights that Markets+ participants actually have the right to."

He said staff's initial analysis indicates that the right to transfer between the West's subregions will not be "materially affected" by NV Energy's decision to commit to EDAM.



| WECC

"What we found is that [transmission rights] remain relatively unchanged without NV Energy's participation in the market," Lucas said.

He told stakeholders during the webinar that establishing effective seams policies will take many parties working together but that SPP is willing to take a leadership role.

"We just believe it's in the best interest of Western consumers," he said. "So, although we don't know where our market seams will be, nor do we know what the specific seams hurdles that we will need to scale, our priority is to entities formally making their choices on which markets they decide to join."

'One Way or Another'

SPP defines seams as neighbors performing the same function, such as acting as balancing authority, transmission service provider (TSP), reliability coordinator, market operator or, particularly in the West, greenhouse gas area.

Carrie Simpson, SPP's senior director of seams and Western services, said during the webinar that after questions arose over the different seams that exist today in the West, "we found that people were using the words interchangeably."

With 33 TSPs and BAs in the West, seams will be an issue. Simpson said the current proposal is to retain CAISO's BA and place EDAM over it, which in turn means the interconnection's longest seam is retained.

"We're going to have seams in the West, one way or the other," she said.

"We have a massive geographic footprint [in the West] and the resources are really far away from where the population centers are, so transmission and the coordination between states is imperative," Staks said at Infocast.

SPP has largely ported its Markets+ proposed design from its RTO design in the Eastern Interconnection. It includes an independent governance structure and a decision-making process that relies on stakeholder consensus.

"We largely took the Eastern marketplace rules ... and modified them to accommodate the differences and the fact that there are BAs and there are TSPs and there are just unique Western differences," Simpson said. "Our approach is to optimize the dispatch of these markets, the SPP market, across all those BAs and TSPs using their full capability.

"This is an important context for how the markets are developing because we're putting markets on top of the seams, instead of getting rid of the seams first and adding markets," she added. "I say that not because it needs to happen that way but more because it's part of the evolution and what's different about the West and the East."

Seams are reduced when BAs or TSPs consolidate their facilities into joint tariffs, such as joining an RTO. Agreements between neighbors coordinating on certain processes can also eliminate seams.

"We're trying, as a market operator, to optimize the seams that do exist in such a way that really minimizes them," Simpson said, noting it will manage the system like an RTO or single BA area. Imports and exports to the market are priced based on footprint needs as a whole and not individual BA areas.

She warned that without optimized seams, Western markets could see revenue and cost allocation equity undermined by internal seams. Equity is a big deal when you are settling $30 billion in market transactions, as SPP did last year.

The seams require intentional policies between BAs and TSPs and market design decisions to reduce the effect of internal seams on market dispatch, Simpson said. She said SPP's marketplace rules have evolved over the last 10 years to "refine equity in cost-allocation principles," and it will continue to do so in the Markets+ design.

JOAs

Joint operating agreements (JOAs) are one option for reducing friction on the seams. SPP has such agreements with MISO, ERCOT and Canadian utility SaskPower. During last January's winter storm, the grid operator was able to rely on JOAs to import about 7 GW of generation to meet unexpected demand.

Lucas said SPP's position remains that Markets+ participants will be incented to strike JOAs that will facilitate trade "above and beyond" 1,000 MW of point-to-point rights that will support the market.

"It can be Markets+ and neighboring markets that really take advantage of the reliability, sustainability and economic benefits that are associated with trade between regions," Lucas said. "We are always focused on taking steps to add value for our participants and their customers and we think that seams and joint operating agreements are a great way to create efficiencies. We believe that anyone who's operating the market will see value in joint operating agreements that allow participants in respective markets to be able to trade effectively, to capture those reliability, economic and sustainability benefits."

As Western markets and their footprints continue to evolve, Simpson said all staff and potential market participants can do is identify "friction points" that may reduce market optimization or make it difficult to move power from one point to another, a market footprint.

"By identifying those things, at least we have a path and a framework for how we can reduce that friction," she said. "The reality is we can start with what we know now. But once we get a better idea of the footprints, that's really when we can engage. We'll know who our neighbors are and how to manage that." ■

FERC Rejects SPP's Proposed Uncertainty Adder

By Tom Kleckner

FERC has rejected SPP's tariff revisions that would modify the adder for uncertainty of expected costs for offers above $1,000/MWh, a modification spurred by Winter Storm Uri.

In its July 11 order, the commission denied the proposed revisions because they directly contradict Order 831, which includes a requirement that any adders included in cost-based incremental energy offers above $1,000/MWh not exceed $100/MWh (*ER24-2002*).

FERC said that in Order 831, it found it is necessary "to place an upper bound on the level of adders above cost" when incremental energy offers exceed $1,000/MWh and stating explicitly that "such adders may not exceed $100/MWh."

SPP proposed in May to allow cost-based incremental energy offers above the threshold to include an uncertainty adder of up to 10% of verifiable short-run marginal costs. The commission said the change would lead to adders that exceed $100/MWh.

The grid operator said it suffered "severe operational challenges" in its footprint during the 2021 winter storm. It received about 50,000 offers that were subject to the Market Monitoring Unit's verification because they exceeded $1,000/MWh.

SPP proposed to modify the uncertainty adder for offers of more than $1,000/MWh from a maximum of $100/MWh to a maximum of 10% of verifiable short-run marginal costs. It said the 10% adder would provide better protection against price volatility in the spot market and help mitigate risk related to fuel procurement cost uncertainties and cost reimbursement during extreme weather events.

The MMU filed comments supporting the tariff revisions. It said the RTO's proposal more effectively reflected uncertainty in the expected cost of energy production and should improve price formation when energy offers are above $1,000/MWh.

FERC said it was "sympathetic to SPP's concerns" and suggested the RTO streamline or automate its manual verification process.

"This, in turn, could improve price formation when offers are between $1,000/MWh and $2,000/MWh," the commission said. ■

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Company Briefs

Ørsted Assumes Full Ownership of Sunrise Wind OSW Farm

Ørsted last week announced it acquired Eversource's 50% share of Sunrise Wind, a 924-MW offshore wind farm located off the coast of New York, for $152 million.

With the closing, Ørsted has assumed full ownership of the project, which has all federal permits in place and recently signed an offshore wind renewable energy certificates contract with NYSERDA. At signing in January 2024, the transaction was valued at $230 million, and the revised closing figure reflects adjustments made due to lower actual versus forecast CAPEX spend between signing and closing.

The project is expected to be operational in 2026.

More: *Offshore Engineer*

Unitil to Purchase Bangor Natural Gas Company

Unitil last week announced it has agreed to purchase Bangor Natural Gas from PHC Utilities, a subsidiary of Hope Utilities, for $70.9 million.

The Company, which opened in 1998, is a natural gas distribution company serving approximately 8,500 customers in Maine.

The transaction, which is subject to approval by the Public Utilities Commission, is expected to close in the first quarter of 2025.

More: *Unitil*

Zachry Updates Layoff Notices, Exit from LNG Project Likely

Construction firm Zachry last week filed updated layoff notices with the Texas Workforce Commission, making its exit from the Golden Pass LNG project likely.

Zachry filed updated layoff notices affecting around 120 jobs, with some layoffs having begun on June 30 and others effective in late August. The filing followed a court hearing that marked a turning point in a legal dispute playing out after Zachry filed for bankruptcy protection in May, blaming its financial struggles on Golden Pass.

Zachry was building the project for Exxon Mobil and Qatar Energy.

More: *Houston Chronicle*

Solar Panel Manufacturer Toledo Solar Ceases Operations

Thin-film solar panel maker Toledo Solar last week announced it will be ending operations and R&D efforts, effective immediately.

The company allegedly started manufacturing cadmium-telluride thin-film solar panels for the residential and non-utility market in 2021 in Ohio. However, First Solar filed a complaint in 2023 alleging that Toledo Solar wasn't making solar panels at all and instead was taking old First Solar panels and rebranding them as Toledo Solar. The companies eventually settled the lawsuit.

Interim President Tom Pratt said the company will take a different business model as it was unable to secure needed licenses to manufacture the panels.

More: *Solar Power World*

Federal Briefs

Man Arrested in Plot Targeting New Jersey Grid

Andrew Takhistov, an 18-year-old New Jersey man allegedly en route to join a paramilitary force in Ukraine, was arrested at an airport last week after sharing his plan with an undercover law enforcement operative to destroy an electrical substation as part of his white supremacist ideology, according to federal prosecutors.

Takhistov instructed the officer to destroy a New Jersey energy facility with Molotov cocktails while he was overseas, detailing how to evade surveillance cameras, discreet parking locations, and escape plans, according to federal court papers.

Takhistov was arrested July 10 at Newark Liberty International Airport as he was planning to travel to Paris, prosecutors said. He is charged with solicitation to destruct an energy facility, which carries a maximum penalty of 10 years in prison and a $125,000 fine.

More: *USA Today*

Army Corps Misses Deadline to Report on Ending Willamette Dam

Delays to a federal report on ending hydropower generation in the Willamette River Basin to save threatened salmon are creating frustration and concern for tribal leaders and conservationists in Oregon.

Congress directed the Army Corps of Engineers in 2022 to produce a report by the end of June 2024, detailing the impacts that eight federal hydroelectric dams in the Willamette River Basin have had on native fish populations over the past 60 years, and the possibility of deauthorizing the dams to save the fish. Ending hydropower generation at the dams can't happen without congressional approval. Instead, the report is sitting in Washington, D.C., under administrative review.

Kerry Solan, a spokesperson for the Portland District of the Army Corps of Engineers, said her office submitted its disposition report to headquarters in D.C. and could not comment further.

More: *Oregon Capital Chronicle*

DOE Offers $1.2B Loan to Expand US Battery Supply Chain

The Department of Energy's Loan Programs Office last week offered a conditional $1.2 billion loan to Entek Lithium Separators, a division of U.S.-based manufacturer Entek, which makes essential battery components.

Entek plans to use the loan to back the financing of a $1.5 billion separator factory in Terre Haute, Ind.

DOE estimates the North American lithium-ion EV battery industry will require 7 billion to 10 billion square meters of annual separator production by 2030.

More: *Canary Media*

State Briefs

ARIZONA

Judge Upholds Tucson's Authority to Restrict Overhead Power Lines

Pima Superior Court Judge Kyle Bryson last week upheld Tucson's authority to prohibit overhead transmission lines in city-designated corridors.

Bryson denied an appeal challenging a Tucson zoning administrator's rejection of part of Tucson Electric Power's plan to build overhead high-voltage transmission lines through midtown. TEP initially sought zoning permission in 2021 to install the overhead 138-kV lines, contending the project was a system upgrade not subject to the prohibition. The judge also said the Corporation Commission has primary jurisdiction over where high-capacity transmission lines are built, but not how they are constructed.

TEP will need to apply for "special exceptions" to the ordinances for the crossings.

More: *Arizona Daily Star*

CALIFORNIA

Napa County OKs Code to Encourage All-electric New Homes

The Napa County Board of Supervisors last week unanimously approved a new building code that will discourage natural gas connections in new residential construction.

The code, effective Jan. 1, encourages all-electric residential construction by default in the county by adding energy use reduction requirements. Homebuilders would also need to offer an all-electric option for interested owners. The code doesn't do the same with non-residential construction but requires that such construction be "electric ready."

The energy commission will need to approve the code prior to the county officially adopting it.

More: *The Press Democrat*

PUC Approves SoCal Edison PPAs

The Public Utilities Commission last week approved five clean energy power purchase agreements submitted by Southern California Edison.

Three of the projects are solar power plants with a total generating capacity of 525 MW, while the other two are geothermal projects that will total 320 MW.

More: *pv magazine*

FLORIDA

Palm Beach OKs Contracts to Bury Utility Lines

The Palm Beach Council last week unanimously voted to award contracts worth nearly $12 million to bury utility lines.

The town began burying all overhead, electrical, phone and cable television lines in 2017 as part of a 10-year, $128 million undergrounding project.

Construction is expected to be complete in 2027.

More: *Palm Beach Daily News*

MICHIGAN

Bill Takes Away Veto Power from HOAs

Gov. **Gretchen Whitmer** last week signed legislation that will invalidate any HOA provisions against a litany of energy efficiency home improvements.

The law covers a range of both high- and low-tech home upgrades from rooftop solar panels and home EV chargers to clothes lines and rain barrels. HOA officials also can't require fees to install energy efficiencies, nor demand post-installation reports or monitor homeowners' energy usage.

More: *MLive*

NRC Launches Environmental Review of Plan to Restart Palisades Plant

The Nuclear Regulatory Commission last week announced it has launched an environmental review of the potential impacts of repowering the Palisades Nuclear Power Plant.

Palisades owner Holtec International plans to restart power production at Palisades, a nuclear plant that was decommissioned on May 20, 2022. If the company is successful, it would be the first time an American nuclear plant is returned to the grid after shutting down.

A draft of the environmental assessment will be available to the public in January.

More: *The Detroit News*

MONTANA

Republicans Urge Reversal of Ruling in Climate Change Lawsuit

Attorneys for Republican officials last week pressed the state Supreme Court to overturn a climate ruling that said regulators were violating residents' constitutional right to a clean environment by allowing oil, gas and coal projects without regard for global warming.

Attorneys for state officials, including Republican Gov. Greg Gianforte, told justices that greenhouse gases from Montana are insignificant on a global scale. They also argued climate change is too broad a problem to solve through the courts and noted state law prohibits the denial of fossil-fuel projects based on carbon dioxide emissions.

The seven justices took the case under advisement. A decision could take weeks or months.

More: *The Associated Press*

SOUTH CAROLINA

PSC Approves Duke Rate Hike

The Public Service Commission last week approved a rate hike for Duke Energy Carolina.

Beginning in August, the average residential customer will see an increase of $12.06 (8.7%) per month. Starting in August 2026, rates will increase by an additional $6.42 (4.3%) per month.

More: *Queen City News*

VIRGINIA

Dominion Energy Plans $500M LNG Storage Facility

Dominion Energy last week filed plans with the State Corporation Commission to build a storage facility capable of holding 2 billion cubic feet of liquified natural gas.

The facility's aim is to provide backup fuel for its Greensville and Brunswick County facilities in case cold weather, natural disasters, cyberattacks or other interruptions cut or slow the flow of gas to the two plants.

If the SCC approves, Dominion aims to start construction next year and complete the project in 2027.

More: *Richmond Times-Dispatch*

RIFA Board Approves Battery Storage Project at Berry Hill Mega Site

The Danville-Pittsylvania Regional Industrial Facility Authority last week approved a battery storage project planned at the Southern Virginia Mega Site.

The lithium-ion battery system would be built on a 4-acre concrete pad and connected to the grid, feeding into an Appalachian Power substation.

Construction is expected to begin in 2026.

More: *Danville Register & Bee*

WISCONSIN

PSC Report Says Major Utilities on Pace to Meet Emissions Goals

All five of the state's major utilities are on pace to hit their carbon reduction goals by the end of the decade, according to a Strategic Energy Assessment report from the Public Service Commission.

Two years ago, the report projected four of the five major providers would fall short of their goals. However, the new draft said all utilities are expected to meet their 2030 goals through coal plant retirements, moving to cleaner fuels, and adding renewable energy resources.

For Wisconsin Public Service, We Energies, Xcel Energy and Madison Gas and Electric, hitting their goals means reducing carbon dioxide emissions by 80% from 2005 levels by 2030. Alliant Energy has a goal of a 50% reduction by 2030. All five hope to achieve a 100% reduction in emissions from 2005 levels by 2050.

More: *Wisconsin Public Radio*

WYOMING

DEQ Approves Rail Tie Wind Farm

The Department of Environmental Quality's Industrial Siting Council last week approved the $500 million Rail Tie Wind Farm in Albany County.

The approval followed four hours of a closed-door meeting, after which the council voted 5-0 to allow the 504-MW project to move forward.

Construction on the 100-plus-turbine project is set to begin this fall.

More: *Cowboy State Daily*