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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Counterflow

By Steve Huntoon

Pay Me Now or Pay Me Later

By Steve Huntoon

You young'uns don't know, but back in the Middle Ages of the 1970s there was a famous commercial for Fram oil filters: You could pay the Fram guy $4 for an oil filter now or pay hundreds for engine repairs later.[1]

Having slightly less pizzazz is the question of how consumers pay for transmission project costs during the pre-construction and construction phases, i.e., before they are completed and placed in service. Consumers can pay a transmission owner's return (aka cost of capital, aka carrying charge) on such costs on a current basis before and during construction (pay now) or start to pay that return when the project is completed (pay later). The former is often called the "construction work in progress" or CWIP approach, and the latter is often called the "allowance for funds used during construction" or AFUDC approach.[2]

Are you with me so far? Let me give a simple example of the difference. A transmission owner spends $100 million on a project in year 1, and let's assume an annual return of 9%. Under the CWIP approach the transmission owner charges consumers $9 million in (or shortly after) year 1. Under the AFUDC approach the transmission owners books the $9 million and adds it to the capital cost (aka rate base) of the project, to be charged to consumers starting when the project goes into service (or is abandoned).

When consumers pay that transmission owner return — now or later — is a timing question. There is no obvious answer to which is better for consumers.

Time Value of Money

All else equal, the answer turns on the time value of money — an esoteric concept that compares what someone would take in the future for not having a given sum today. So, for example, if someone would be indifferent to receiving $105 a year from now versus having $100 today, we would say that person has a time value of money with a 5% "discount rate." In the context we're considering, the question is whether the consumer would rather pay the transmission owner now or pay a higher amount later.

Construction of 345-kV transmission line foundations | *Michels Power*

We can take a shot at estimating this. There's about $18 trillion in bank accounts averaging 0.1% interest,[3] so that might be a decent estimate of consumers' discount rate. If someone would accept $100.10 a year from now on his/her $100 today then there's a really low discount rate.

At the other end of the spectrum are consumers with credit card debt paying 16% interest, implicitly choosing (or having to pay) a 16% discount rate.[4] If they don't pay the transmission owner that $100 up front, instead paying down credit card debt by that amount, they could save $16 in credit card interest. But there's around $840 billion in aggregate credit card debt,[5] versus *$18 trillion* in bank accounts, so there's a rough ratio of 20-1 for a low discount rate of 0.10% versus a high discount rate of 16%.

I hope I haven't lost you because we still need to compare consumers' discount rate with an estimate of what the transmission owner charges consumers for the time value of money. It's roughly 9% using current allowed returns (weighted average cost of capital including income tax allowance).[6]

Based on the foregoing, the vast bulk of consumers would rather pay now than pay later. For every $100, forego $0.10 now versus pay $9 a year from now. Conceptually most consumers would take $100 from a bank account, foregoing $0.10 in annual interest, in order to pay a transmission owner that would otherwise charge an extra $9 a year later.

Cut to the April NOPR

Now we can cut to FERC's April Notice of Proposed Rulemaking, which suggests the opposite — that consumers overall would rather pay later. The NOPR says: "… we are concerned that the CWIP Incentive, if made available for Long-Term Regional Transmission Facilities, may shift too much risk to consumers to the benefit of public utility transmission providers in a manner that renders commission-jurisdictional rates unjust and unreasonable."[7]

There's no analysis supporting this conclusion

Counterflow

By Steve Huntoon

— it's just asserted. As I pointed out above, the transmission owner charges consumers for its return under either approach; it's just pay me now or pay me later. And most consumers would rather pay now because of their low discount rate, as well as to avoid what the commission has called "rate shock" if the return on large projects is deferred and accumulated until the project goes into service.[8]

Perhaps the NOPR's focus is on situations when the project is abandoned instead of going into service. The NOPR says: "Should the regional transmission facilities not be placed in service, then ratepayers will have financed the construction of such facilities that were not used and useful, while ultimately receiving no benefits from such facilities."[9]

There are problems with this focus. First, abandoned project costs are a small percent of total transmission costs because the vast majority of projects are not abandoned and because abandoned projects are abandoned in the *pre*-construction phase where relatively few dollars have been expended. So, to have abandoned project costs decide the overall CWIP v. AFUDC issue is to have the tail wag the dog.

Second, under commission precedent, consumers generally pay that transmission owner return even for abandoned projects that provide consumers no benefit.[10] The NOPR seems to assume that it would spare consumers from this cost of abandoned projects when the commission's own rules and precedent are the opposite.

The NOPR doesn't propose to change the commission's rules and precedent on this (although Commissioner Mark Christie's concurrence seems to suggest it does[11]). And the commission seems unlikely to change the rules given the inevitable transmission owner objections that this would discourage the big transmission projects that the commission wants to promote.

And let me add that even if recovery of abandoned project costs were to be disallowed then transmission owners would argue for a higher rate of return because of increased investment risk — another wrinkle on pay me now or pay me later. Consumers seem unlikely to win that tradeoff against transmission owner lawyers and consultants (who consumers pay for[12]). And a risk of disallowance might skew a transmission owner's incentive against abandoning a project that ought to be abandoned.

Wrapping Up

OK, I'll wrap this up by saying I would love to be wrong — that somehow consumers would be better with the AFUDC pay-later approach. But that doesn't seem possible for projects that go into service. And as for abandoned projects, consumers *might* be better off but only if return on capital were actually denied instead of deferred and billed to consumers later.

P.S. errata note, in my last column on transmission competition the references to $136,070,000 should have said $128,750,000. Import unchanged. I regret the error. ■

[1] https://www.youtube.com/watch?v=OHug0AIhVoQ. I may be forgetting that later generations never change their own oil so are utterly baffled by this whole flashback.

[2] These terms can be confusing. Sometimes the return/carrying charge amount is referred to as AFUDC, which is added to the CWIP balance. Also I should note that generally under both the AFUDC and CWIP approaches, the amount in question is return on capital, not return of capital. In both approaches the capital costs of construction are treated the same – recovery from consumers is deferred until the project goes into service (or is abandoned).

[3] https://fred.stlouisfed.org/series/DPSACBW027SBOG; https://www.bankrate.com/banking/savings/average-savings-interest-rates/

[4] https://www.lendingtree.com/credit-cards/average-credit-card-interest-rate-in-america/

[5] https://www.lendingtree.com/credit-cards/credit-card-debt-statistics/

[6] For illustrative purposes take last year's settlement of a rate complaint against PPL Electric Utilities, a PJM transmission owner, with an allowed common equity return of 10.4% and allowed equity/debt ratio of 56%/44%, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=F83FB3CC-1092-CA7D-87C8-7B6442400000. Grossing up the equity return for a 21% federal income tax rate yields a pretax equity return of 13.2%. Applying the equity/debt proportions to that equity return and to a long-term debt cost of 3.6% from data in PPL's Form 1 yields a weighted average cost of capital of 9.0%. Your mileage may vary.

[7] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (April 21, 2022) ("NOPR"), at P 332.

[8] Potomac-Appalachian Transmission Highline, L.L.C., 122 FERC ¶ 61,188, at P 42 (2008).

[9] NOPR, at P 331.

[10] Order No. 679, 116 FERC ¶ 61,057 at P 163 (2006); MidAmerican Central California Transco, LLC, 168 FERC ¶ 61,197 at P 3 (2019); GridLiance West Transco LLC, 164 FERC ¶ 61,049, at P 19-20 (2018); Potomac-Appalachian Transmission Highline, L.L.C., Opinion No. 554, 158 FERC ¶ 61,050, at P 5, fn. 10 (2017) ("PATH"); Xcel Energy Services, Inc., 121 FERC ¶ 61,284 at P 62 (2007).

[11] Commissioner Christie concurring, at P 5 and 15. If the Commission actually intends what Commissioner Christie suggests it does, then a Final Rule should make that clear.

[12] PATH, at P 134.

FERC/Federal News

Biden: 'I Will not Back Down' on Climate Action

Clean Energy Advocates Call for Tax Extenders

By K Kaufmann

With Sen. Joe Manchin (D-W.Va.) once again shutting down negotiations over a budget reconciliation package that includes clean energy incentives, a range of voices and views have emerged to answer the crucial question of what comes next.

President Biden and Energy Secretary Jennifer Granholm both struck a note of defiance. In a *statement* released by the White House on Friday, the president said the need for climate action remained as urgent as ever, and he vowed not to back down.

"If the Senate will not move to tackle the climate crisis and strengthen our domestic clean energy industry, I will take strong executive action to meet this moment," Biden said. "My actions will create jobs, improve our energy security, bolster domestic manufacturing and supply chains, protect us from oil and gas price hikes in the future, and address climate change."

Granholm took to Twitter with a *thread* acknowledging her frustration while calling for broad action at all levels. "We will fight like hell with the tools we have to build a clean energy future and move forward on climate action," she said. "This moment calls [for] every city, state, tribe, business, community and organization to get in the fight if you're not already. We have to leave it all on the field."

In an *interview* on West Virginia MetroNews radio on Friday, Manchin maintained that he wants action on climate, but in the wake of June's 9.1% *consumer price index* — up 1.3% from May — fighting inflation and reducing the federal deficit have to come first.

Manchin in December gave similar reasons for pulling out of negotiations over the original Build Back Better Act. The bill was passed by the House of Representatives, but all 50 Republicans in the Senate are opposed. Democrats want to use the reconciliation process, which would only require a simple majority vote (with Vice President Kamala Harris breaking the tie) if Manchin joined in support, to bypass a filibuster.

"We've had good negotiations. … Our staffs have been working diligently for the last two to three months," Manchin told Hoppy Kercheval, host of "MetroNews Talkline." But he also said he had been clear with Senate Majority Leader Chuck Schumer (D-N.Y.) and other Senate staffers that his support would depend on the June inflation figures that were released on Wednesday.

President Biden (left) and Sen. Joe Manchin (D-W.Va.) | *The White House / © RTO Insider LLC*

"They knew exactly where I stood," he said. "When we saw 9.1%, that was an alarming figure to me … so I said, 'Oh my goodness, let's wait; this is a whole new page.'"

With the war in Ukraine, and Europe looking to the U.S. to replace Russian fossil fuels, Manchin argued that the U.S. can decarbonize while continuing to "produce more fossil [fuel] cleaner than anyone in the world and replace that dirty fossil going into the atmosphere."

"Also, what you can do is invest in the cleaner technologies that we know that will work," he said. "We know hydrogen is going to work; we know we need storage for batteries, and battery storage takes care of wind and solar; we know that. New transmission — we know all these things. Geothermal and small nuclear reactors, I'm for all these things."

Manchin said he is also consulting economic experts to ensure that any tax increases that would be used to fund clean energy incentives don't cause further inflation or cause companies to cut back production or lay off employees. A budget reconciliation package, with or without energy incentives, could still be passed when Congress returns from its August recess in September, he said, "if it's a good piece of legislation."

Post-election Green Pivot?

Biden's statement did not detail the specific executive actions he might take to provide momentum for his stalled vision for an aggressive climate agenda. Manchin's latest defection comes two weeks after the U.S. Supreme Court's decision in *West Virginia v. EPA* undercut EPA's ability to cut emissions at existing power plants through generation shifting — changing out dirtier fossil fuels for cleaner low- or no-carbon generation. (See *Supreme Court Rejects EPA Generation Shifting*.)

Biden has already used executive orders to set the U.S. on a path to a 100% carbon-free electric system by 2035 and a net-zero economy by 2050. More recently, he invoked the Defense Production Act to ramp up clean energy manufacturing and ordered a two-year suspension of potential tariffs on solar cells and panels from Cambodia, Malaysia, Thailand and Vietnam in the face of a pending Commerce Department investigation. (See *Biden*

FERC/Federal News

Waives Tariffs on Key Solar Imports for 2 Years.)

Meanwhile, the Department of Energy is continuing to distribute new funding, much of it from the Infrastructure Investment and Jobs Act, for clean energy initiatives.

If fully funded, the law will continue to pump out funds for clean energy through 2026. For example, on Thursday, the DOE announced $29 million in funding, about a third from the IIJA, to increase the reuse and recycling of solar technologies and develop solar panel designs that reduce the cost of manufacturing.

In the wake of *West Virginia v. EPA*, California Gov. Gavin Newsom (D) and Washington Gov. Jay Inslee (D) both vowed to step up their efforts to cut carbon emissions. More recently, the D.C. Council passed legislation, pending before Mayor Muriel Bowser, that would ban natural gas hookups in new construction and require all new construction and major renovations in the district to be net-zero by 2026.

But, in its analysis of the post-Manchin state of play, industry analysts ClearView Energy Partners suggest that if the Republicans do gain majorities in the House and Senate in the midterms, Biden might "pursue muscular intervention into energy markets and capital formation … potentially including 'a climate emergency' declaration."

"If the White House was also modulating its oil and gas policy in recent months to woo [Sen.] Manchin's support for clean energy incentives, then Manchin's latest defection could bring an even bigger post-election green pivot," ClearView said.

In the absence of a "mini-BBB" budget reconciliation deal, ClearView also sees the potential for a congressional pivot toward passing a package of clean energy tax credit extenders in the lame-duck session between the midterm elections and the opening of the next Congress in January. Although the option of tax extenders has not been discussed thus far, "we would not be surprised to see extenders text proposed (or at least mooted) by the House Ways and Means and Senate Finance Committees before lawmakers leave for their August recess," ClearView said.

Some Republicans might support extender legislation for two reasons, ClearView said. First, even if the GOP takes both houses of Congress, Biden will still have veto power, and second, a growing number of red states are now generating about half of the country's onshore renewable and other clean forms of energy.

Underway and Unstoppable

Perhaps with such tax extender legislation in mind, clean energy advocates and business groups continued to call for congressional action on federal tax credits and other incentives, echoing administration arguments that they will help fight inflation, spur economic growth and protect energy security.

Clean energy tax credits "would deliver much needed relief, helping to cut energy prices and reduce U.S. dependence on price-volatile fossil fuels, by spurring the domestic manufacturing and deployment of clean, affordable and reliable advanced energy technologies," said Heather O'Neill, president of Advanced Energy Economy. "Failing to use this opportunity to boost the domestic advanced energy manufacturing industry would mean American workers get less benefit from the world's transition to clean energy, and would all but assure that our economic competitors, particularly China, reap the economic rewards instead."

O'Neill and others also pushed hard on the business case for clean energy. The transition is "underway, and it is unstoppable," O'Neill said. "We see it in corporate procurements driving clean energy investment across the country. We see it in consumer demand for electric vehicles as drivers seek to free themselves and their pocketbooks from the volatility of gasoline prices."

"The private sector is making record-level investments in the clean energy transition, but a predictable and long-term national tax and policy framework is needed to support accelerated and expanded deployment," said Lisa Jacobson, president of the Business Council for Sustainable Energy.

Any effort to find common ground on tax credits might begin with carbon-capture technologies and that industry's 45Q tax credit, both of which have had strong support from Manchin, whose family still operates the coal company he started.

"While there is uncertainty about next steps with the reconciliation process, it remains clear that there is broad, bipartisan support for Congress to provide robust investments in carbon-management policies," said Madelyn Morrison, external affairs manager for the Carbon Capture Coalition. "To achieve carbon capture and removal at climate scale, Congress must deliver the full portfolio of federal policy support for carbon management in any moving legislative vehicle, including a direct-pay option for the 45Q tax credit." Manchin has recently opposed any direct-pay options for clean energy tax credits. ■

FERC/Federal News

Report: US Energy Sector Lags on Cyber Preparedness, Response

Only 10 to 20% of Grid Subject to FERC, NERC Reliability Standards, Atlantic Council Says

By K Kaufmann

| *Shutterstock*

The clean energy transition in the U.S. is creating a grid that is increasingly distributed, increasingly digital and, therefore, increasingly vulnerable to cyberattacks.

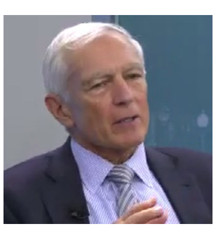
But, according to a *new report* from the Atlantic Council, even as the war in Ukraine has raised concerns about Russia deploying a range of cyber disruptions to energy systems in the U.S. and Europe, "the public and private sectors lack a unified strategic framework to secure energy infrastructure against cyber threats."

"Existing authorities intended to clarify responsibilities for cybersecurity and assign roles to the Department of Homeland Security, the Department of Energy and other agencies are ambiguous in practice," the report says. "Ambiguities and gaps in jurisdiction lead to weaker cybersecurity practices, wasted effort by government, confusion for the private sector and missed opportunities for timely information sharing that would strengthen security."

Former DHS Secretary Michael Chertoff | *Atlantic Council*

At a launch event for the report on July 12, former Homeland Security Secretary Michael Chertoff said the immediate need is to bring "all the tools in the toolbox together in order to make sure we have both public and private coordination and strategy in terms of protecting our infrastructure."

Security is not "just protecting your endpoints," Chertoff said. "It involves the way you structure your network, how you build resilience, how you respond to attacks, how you warn of attacks and how you exercise and train people."



Ret. Gen. Wesley Clark | *Atlantic Council*

Chertoff, who led DHS under President George W. Bush, and retired Army Gen. Wesley Clark were co-chairs of the Atlantic Council task force that produced the report, and they opened the launch event with a fireside chat-style conversation.

Entitled, "Securing the Energy Transition Against Cyber Threats," the report outlines a broad set of solutions rooted in a collaborative approach to the roles and responsibilities the public and private sectors each must take on to keep the country's rapidly transforming grid secure. On the federal side, for example, the report says a strategic realignment is needed between FERC, DHS and DOE, the three federal agencies tasked with different aspects of energy system security.

While FERC and NERC set reliability standards for the bulk power system, only 10 to 20% of the U.S. electricity system falls under their jurisdiction, the report says. Distribution systems are not covered, which means the U.S. has "no single central authority for cybersecurity preparedness," the report says, citing a *2016 report* from the Massachusetts Institute of Technology.

"The only way we're going to fix this really is to stay on top of it," said Clark, who served as NATO Supreme Allied Commander for Europe under President Bill Clinton. "Because not only do you have to have public attention, which the Ukraine war has helped us to develop, but what you're bringing attention to is constantly evolving underneath as new technology emerges, new business investments are made and new threat attack vectors are developed."

Looking to the challenges ahead, Chertoff said, "Much of the regulatory and security architecture built in the U.S. — and frankly including NATO — over the last few years was built episodically. The pieces don't necessarily fit together. There's overlap; there's duplication; there's even inconsistency.

"It's really time to sit down and map out what is our strategic architecture," he said. "What are the standards we should enforce and promote? And what are the training and planning exercises we have to engage in so we can respond quickly?"

The report's other recommendations for government include:

- updating federal policy directives to "crystallize" the role of DHS' Cybersecurity and Infrastructure Security Agency as "leader of the national unity effort for critical infrastructure protection";
- realigning "the jurisdictional bounds of Senate and House committees to minimize areas of overlapping oversight" resulting from the multiple committees focused on

FERC/Federal News

different aspects of cybersecurity; and

- establishing a cyber bank or low-interest cyber fund to "help qualifying companies ... obtain financing at low rates — which could also include loan forgiveness provisions tied to metrics."

No More 'Silver Bullets'

On the business side, the report calls for urgent "improvements in how the private sector secures its critical technologies and works with the public sector to respond to the most accurate and timely threat information."

Former FERC Commissioner Neil Chatterjee | *Atlantic Council*

Speaking on a panel at the launch event, former FERC Commissioner Neil Chatterjee said, "The landscape of 21st-century warfare has evolved to such a point that now private sector companies find themselves on the frontline." A cyberattack on critical energy infrastructure may "have the same national security, economic security impact as a military-style attack," said Chatterjee, who is now a senior adviser at law firm Hogan Lovells.

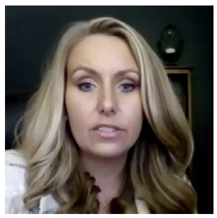
While voluntary standards — like *ISA/IEC 62443* — provide a good baseline for corporate efforts to ensure supply chain cybersecurity, the lack of consistent, cross-industry standards leaves open potential "attack pathways," particularly with operational technology, the report says.

"Unable to rely on a known standard or a regulatory body, each organization must expend effort assessing its own supply chain or accept increased risk," the report says. "Unfortunately, the energy system in the United States has never been subject to a system wherein OT products connected to the grid must meet an enforceable set of standards beyond the most rudimentary and basic principles of cybersecurity."

Leo Simonovich, Siemens Energy | *Atlantic Council*

Leo Simonovich, global head of industrial cyber and digital security at Siemens Energy, agreed that "many utilities are struggling to get their hands around the issue of industrial cyber operational technologies. ... But to better understand risk, you have to be able to detect, to understand your exposure, and yet many utilities today are operating blind. They don't have the capabilities to be able to adopt many of these technologies."

Getting advanced security systems to small and medium-sized utilities — such as municipals and cooperatives — should be a particular priority, Chertoff said. They are an integral part of the energy ecosystem, he said, but "they don't have the knowledge or the economic ability to raise their level of security."



Megan Samford, Schneider Electric | *Atlantic Council*

Megan Samford, chief product security officer with Schneider Electric, pitched hard for 62443 as a possible solution to this economic and technical divide. The standard can "tell you what needs to be done at every level by the different parties invested, and it can show you over time how you could move" from very basic to more sophisticated levels of cybersecurity.

The industry needs to stop chasing "silver bullets," she said, and instead "draw a line in the sand and ... say, 'We're going to depend on implementation of a standard, and we're going to measure performance against the compliance of that standard.'"

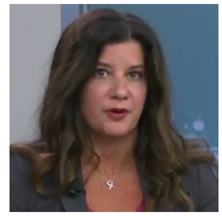
But neither industry nor government can ensure system cybersecurity alone, nor should they be expected to, Clark said. Given the nature of the energy industry and the often slow pace of federal and state regulation, change is likely to be incremental, he said.

"If you're going to put in higher standards both for IT and OT, you're going to have to resource it," he said. "And this means the federal government is going to have a greater responsibility to help the widely distributed participants in the power sector fund what they need to keep the country secure."

Moving at the Speed of Attackers

On a more granular level, Simonovich said that utilities need to define "ownership of operational technology," which is often split between "the folks who run the plants and the IT security teams."

"One of the best things we can do is encourage defining a unified operating model between those two functions within organizations and then ... develop roadmaps that drive change, not just in creating better hygiene, but also in creating a more innovative approach to driving adoption of technology," he said.



Adrienne Lotto Walker, NYPA | *Atlantic Council*

State regulators and policymakers also have a critical role to play in ensuring cybersecurity is "embedded" in the policies and projects they advance, said Adrienne Lotto Walker, chief risk and resilience officer for the New York Power Authority.

"You see a lot of [requests for proposals] getting issued out of states and ... a lot of policies being made at the state level that are focused on decentralizing the grid, clean energy, but they tend to be devoid of embedding cybersecurity," Walker said. "The RFP will literally say nothing about how it's going to be connected, what the cyber architecture will look like."

Another major challenge is improving communication and critical information sharing on cyber threats or attacks between business and government, the report says.

"Information and threat intelligence must move at the speed of attackers," the report says. "Unfortunately, this [information] sharing is often bogged down by a complex intragovernmental system riddled with duplicative actors and processes making it difficult, costly and inefficient for the private sector to cooperate with their government counterparts."

Liability protection is one facet of the problem. Companies may be hesitant to share information with federal agencies, fearing "their own data might be used against them by regulators or law enforcement officials should an event occur," the report says.

A 2002 law gives some protection to companies sharing information with DHS, but a 2015 law also gave DOE and FERC the ability to provide liability protection to energy companies sharing information with them. The government should consolidate or reconcile the protections that the different agencies can provide in a common framework, the report says.

"The purpose of information in my mind should never be information sharing for information sharing," Samford said. "Sharing information is needed to give decision-makers maneuver room ... to adjust plans; make calls; to shore up response plans," she said. "If the war is being brought to the private sector, then there has to be a consistent framework that is used for the private sector to interact with the government." ■

CPUC Opens 'Critical' Demand Flexibility Proceeding

By Hudson Sangree

The California Public Utilities Commission launched a proceeding Thursday aimed at shoring up grid reliability and soaking up more electricity from renewable resources by using real-time rates to influence customer demand.

The new *order* instituting rulemaking (OIR) is intended to "enable widespread demand flexibility through electric rates," the commission said in a news release. "The concept of demand flexibility allows consumers to play a key role in the operation of the state's electric grid by reducing or shifting their electricity use during peak-use periods in response to a price signal or other incentive."

A major goal is reducing solar curtailment by increasing electricity use during the day, when solar power is abundant and demand low, including by charging electric vehicles during those times.

"I want to highlight the importance this rulemaking is going to be and the critical role it's going to play in designing our future grid," Commissioner Darcie Houck said. "It's probably one of if not the most, important rulemakings we're going to do during my term here as a commissioner.

"Our electric grid was originally designed with the assumption that customer demand for electricity was inflexible, and during the majority of the last 140 years, that was the correct assumption," Houck said. "Customer demand was indeed inflexible. We did not have the tools or the technologies to manage demand, nor did we necessarily need to do so because we relied on energy supply being flexible."

"As we move toward a very different energy landscape … we need to make adjustments," she said.

California has experienced reliability crises in recent years as it attempts to reach its 100% clean energy goal by 2045 as extreme weather, prolonged drought and massive wildfires plague the West. The retirement of fossil fuel plants and their replacement with weather-dependent variable resources has exacerbated the problem.

Energy emergencies occurred the past two summers in California during heat waves, when solar ramped down in the evening and demand from air conditioning remained high. In one instance last July, a wildfire shut down major transmission lines from the Pacific Northwest, exacerbating tight supply.

In August 2020, CAISO was forced to order rolling blackouts during a severe heat wave, when imported electricity from the Desert Southwest dwindled and triple-digit temperatures continued after dusk.

In response, the CPUC *issued* expedited decisions last year to try to bolster reliability in the next three summers.

One of those decisions expanded existing demand-reduction efforts, and another created new ones, including two pilot programs to test the effects of dynamic rates that change rapidly based on grid conditions, including energy emergencies. (See *CPUC Proposes Summer Reliability Measures*.)

The new demand flexibility proceeding is connected with a June 22 *white paper* by the CPUC's Energy Division that examines using advanced technologies and real-time price signals to encourage consumers to cut back on energy use when supply is tight and prices high, and to charge EVs or run their dishwashers when prices are lower, such as during the day when solar power is plentiful and cheap.

The white paper addresses the challenges the state faces while transitioning to clean energy and electrifying transportation and buildings. Scaling up demand response programs to cut energy consumption at key times is among its priorities.

| *Shutterstock*

The state's current patchwork of DR programs, which pay customers to reduce consumption, is insufficient, it says. The white paper identifies strategies for broadening demand-side efforts, including by introducing dynamic energy prices based on real-time wholesale energy costs and localized marginal costs and making sure consumers have easy access to those prices online.

A workshop on the white paper is scheduled for this Thursday.

The demand flexibility rulemaking will address issues, outlined in the order, such as how the CPUC should "update its rate design principles to enable widespread demand flexibility to improve system reliability and advance the state's climate goals in an affordable and equitable way."

Two or more working groups will develop proposals for the proceeding. The CPUC expects to issue a scoping memo this fall followed by a proposed decision, with a commission vote in the first half of next year. ■

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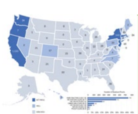

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CAISO/West News

NV Energy Surpasses 2021 RPS Requirement

By Elaine Goodman

NV Energy exceeded Nevada's renewable portfolio standard requirement of 24% in 2021, with nearly 31% of its retail energy sales coming from renewable resources and related credits, according to a report approved by state regulators last week.

NV Energy subsidiary Sierra Pacific Power, which serves northern Nevada, achieved 31.9% renewable energy last year. Southern Nevada subsidiary Nevada Power reached 30.1% renewable energy. The statewide weighted average was 30.7%, according to the report filed by the utility in April.

Last year's adjusted retail sales were 8,728,248 MWh for Sierra Pacific and 20,712,404 MWh for Nevada Power.

The Public Utilities Commission of Nevada (PUCN) voted 3-0 on July 12 to approve the *report* and confirm that NV Energy complied with the 2021 renewable portfolio standard.

50% by 2030

Nevada's RPS was 24% last year, an increase from 22% in 2020. The RPS grows to 29% in 2022 and 2023; 34% in 2024 through 2026; 42% in 2027 through 2029; and 50% in 2030. NV Energy said it is "well on its way" to meeting the 50% renewable requirement by 2030.

"Our commitment to evolving our generation mix is one of many ways we are helping meet our state's sustainability goals," Dave Ulozas, NV Energy's senior vice president of energy supply, renewables and origination, said in a *release* shortly after the utility filed its report with PUCN.

Last year was the 12th year in a row that the company surpassed the state's renewable energy requirement, the release said.

DSM, Carryovers

Under Nevada statute, energy efficiency measures may count toward up to 10% of the annual RPS requirement, through 2024. After that, energy efficiency measures — included within demand side management (DSM) — can't be used toward meeting the standard.

NV Energy used energy savings from DSM to satisfy 10% of its RPS requirements last year.

In addition, the utility used excess portfolio credits carried over from 2020 to help meet last year's RPS requirement. And surplus credits from last year will be carried over to this year.

State law allows a utility to sell excess portfolio credits when the surplus is more than 10% of the required amount. If the surplus is more than 25% of the amount needed to meet the RPS, the utility is directed to "use reasonable efforts to sell" credits in excess of 25%.

Sierra Pacific went over the 25% threshold with its surplus portfolio credits and solicited offers to buy them. Although the utility received seven offers, it ultimately decided to keep the credits in case it needs them later, according to the report.

Nevada Power had surplus portfolio credits in the 10% to 25% range. NV Energy said it would consider selling the credits "if the circumstances are favorable and the sale benefits our customers."

New Solar Projects

At the end of 2021, Nevada Power had about 1,570 MW of renewable generation capacity in service, according to NV Energy's filing. Nevada Power added one utility-scale renewable project last year, Copper Mountain 5, a 250 MW solar facility in Boulder City.

In addition, Nevada Power had nine solar projects totaling 2,044 MW in development at the end of last year. Eight of those projects include battery storage.

Sierra Pacific finished the year with about 692 MW of renewable capacity in operation. During 2021, one new project was added: the 101 MW Battle Mountain solar facility, which includes 25 MW of storage.

The utility also had six solar projects with a combined total of 824 MW in development at the end of the year. All the projects include battery storage.

NV Energy's filing described a "positive" outlook for both of its subsidiaries to comply with the RPS and other future credit commitments.

However, the utility noted some risks. In particular, delays in receiving solar panels and other project components are causing project completion dates to be pushed back and could result in project cancellations, the RPS report said.

"Delays and shortages can drive up costs to a point where a project that was previously economical becomes uneconomical," NV Energy said. ■

New solar projects are helping NV Energy meet requirements of Nevada's renewal portfolio standard. | *MYR Group*

ERCOT News

ERCOT Demand Hits Record for 9th Time

Texas Grid Operator Continues to Battle High Heat, Demand

By Tom Kleckner

Warnings that this week would include the highest temperatures yet this summer proved to be accurate Monday as ERCOT set yet another record for peak demand, its ninth of the year.

Demand averaged 79.038 GW during the hour ending at 6 p.m. CT. That shattered the previous mark of 78.4 GW set July 12 and marks the first time it broke 79 GW.

The record is likely to be short-lived, as ERCOT is projecting demand to break 80 GW today and Wednesday.

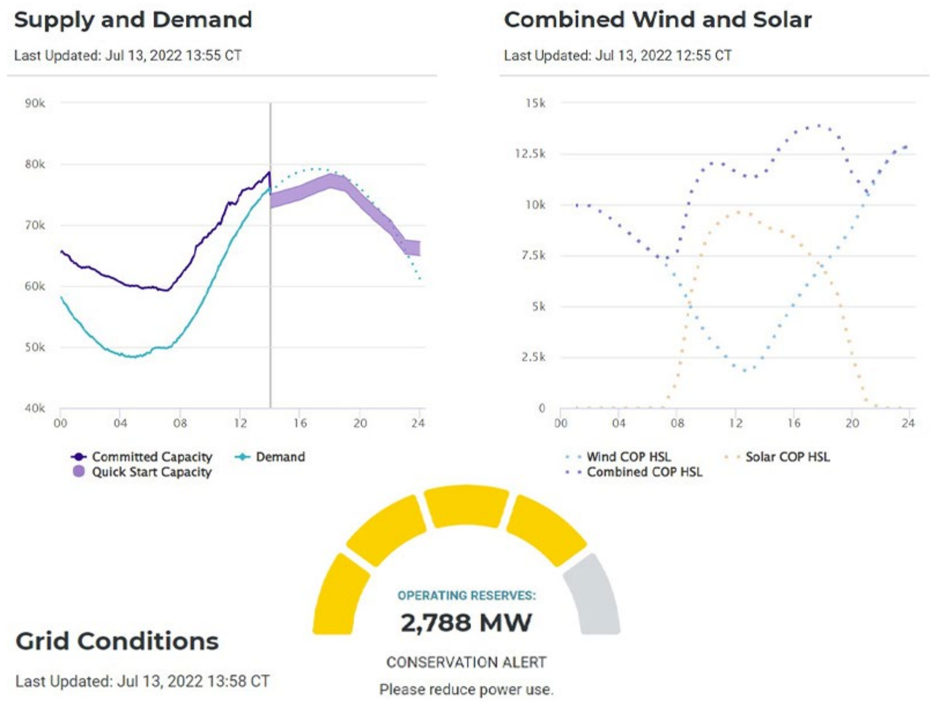
Temperatures in Dallas were predicted to approach 110 degrees Fahrenheit early this week before cooling off into the low 100s. Texas has already suffered through its hottest May and June on record, and meteorologists *expect more of the same* through this month. Heat advisories remain in effect for much of the state.

The National Weather Service *said* widespread heat is highly predictable through Wednesday, and it has *declared* a moderate to high risk of excessive heat into August.

The record demand, 13 GW of thermal outages and reduced renewable production last week forced ERCOT to issue two *conservation appeals* to Texans and businesses. (See *ERCOT Dances with Danger Again*.)

"We want to be respectful of Texans, so we will only call for conservation if we need it," staff said in an email to *RTO Insider*. They said the July 11 conservation appeal successfully reduced demand by about 500 MW.

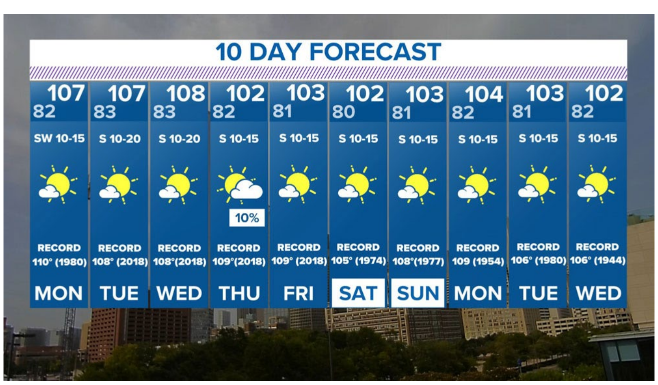
Demand peaked above 77 GW from July 5 to 13 before dropping to just over 70 GW heading into the weekend.



Grid conditions Wednesday afternoon as ERCOT battled tight conditions. | *ERCOT*

The grid operator's operations center has issued several watches in recent weeks because of projected reserve capacity shortages without a market solution that could lead to an energy emergency alert.

ERCOT said the forced thermal outages exceeded its forecasts. It was expecting only 67 of its 80 GW of installed thermal capacity to be available July 13 during the afternoon's tightest hour (3-4 p.m.). Wind generation was again below its historical usage, dropping to 750 MW, about 2% of capacity, after the conservation period passed. Cloud cover in West Texas initially reduced the amount of available solar generation by almost 2 GW.



Dallas Forecast | *WFAA-TV*

Operating reserves stayed below 3 GW during much of the afternoon.

Interim ERCOT CEO Brad Jones *reminded* the *Houston Chronicle* on July 12 that the grid operator is now calling for conservation earlier to help the grid avoid emergency conditions.

ERCOT deployed 927 MW of non-spinning reserves at 12:39 p.m. and then called on emergency response service (ERS) at 2:55 p.m. shortly before physical responsive capability fell below 3 GW. That forced dispatchers to issue another advisory.

During its open meeting Thursday, the Texas Public Utility Commission *approved an order* that increases ERCOT's annual ERS budget to $75 million and allows the grid operator to broach this amount by up to $25 million for contract term renewals. ERCOT will be able to access the additional $25 million immediately upon the effective date of this rule (*53493*).

The grid operator said Monday morning that the Texas Commission on Environmental Quality (TCEQ) will allow resources to exceed their air-permit limits to ensure all possible generation is available to serve system demand. The TCEQ's enforcement discretion began at noon and was expected to end at 9 p.m. Monday.

The commission allowed similar exceedances July 8-14. Prices exceeded the $5,000/MWh offer cap for four hours Wednesday, reaching as high as $5,500/MWh. Monday's prices settled at a high of $1,419/MWh during the interval ending at 4:45. ■

ISO-NE Says No Extra Winter Programs Make Sense this Year

By Sam Mintz

Despite consternation over the state of New England's grid in the winter, ISO-NE sees no viable option for an out-of-market solution it could enact this year, officials told a stakeholder committee last week.

After about a month of reviewing its options, during which the grid operator looked at reviving two previously enacted winter programs, the recommendation to take no action leaves the region hoping for a mild winter.

ISO-NE had considered bringing back the Winter Reliability Program or starting the Inventoried Energy Program a year early. (See *ISO-NE Weighs Reviving Reliability Programs for this Winter*). But its analysis found that both of those programs carried cons and costs that would outweigh their potential benefits, the RTO told the Markets Committee in New Hampshire last week.

"Neither [program] is expected to provide significant benefits under extreme weather conditions, as their incremental reliability benefits are minimal given prevailing market conditions," ISO-NE said in its presentation to the MC.

The Winter Reliability Program, which compensates resources for their unused fuel at the end of winter, would cost an estimated $170 million, nearly seven times as much as it cost when it was last used in 2017-2018. That includes what the RTO called "speculative" benefits, because there are already strong incentives for generators to maintain oil inventory even without the program in place.

The Inventoried Energy Program, which compensates resources for up to three days of inventoried energy that can be converted to electricity, has been approved for the 2023-2025 winters but will have to be changed subject to a recent court ruling. (See *Court Strikes a Blow to ISO-NE Winter Plan*.) It would cost an estimated $157 million and also carries questionable benefits.

| Matthew T. Rader, CC BY-SA 4.0, via Wikimedia Commons

Stockpiling Fuel

So with those options off the table, ISO-NE is hoping that cold weather doesn't strain the system. A mild winter, like last year's, would be manageable for the grid operator to get through, with no capacity deficiencies or load-shed events, the officials said.

A moderate winter, like in 2017-2018, could cause ISO-NE to rely on capacity deficiency procedures, laid out in OP-4. An extreme case, with sustained cold weather, could lead to load shedding and rolling blackouts.

A key question is whether generators will have enough on-site fuel this winter. Currently, New England's fuel oil inventory is about 81 million gallons, a third of its storage capacity, ISO-NE said. But generators are expected to replenish their stores up to about 110 million gallons, with many of them waiting until fall as prices are expected to decrease by then.

LNG availability is also expected to be about the same as recent years, ISO-NE said.

In the event of fuel shortages, ISO-NE said it has a few levers it can pull, including asking for waivers of the Jones Act, emissions rules and hours-of-service restrictions for drivers carrying fuel. It could also ask the government to activate military staff or equipment to help move fuel.

And, as was heavily used in Texas last week, the grid operator could ask customers to help with emergency conservation measures.

Looking Forward

"Energy adequacy will continue to be a concern beyond this winter because of limited infrastructure and vulnerability to large source-loss contingencies, which short-term programs will not address," ISO-NE said in its presentation.

FERC's September forum in Vermont will continue to address those issues, helping to "better inform the future longer-term solution space," the grid operator said.

Work is also underway on a study with the Electric Power Research Institute looking at the operational impacts of extreme weather. ■

ISO-NE News

Stakeholders Lob Capacity Accreditation Ideas at ISO-NE

By Sam Mintz

A Community Energy solar project in Barre, Mass. | *Community Energy*

As ISO-NE starts moving forward with its work to update resource capacity accreditation rules in New England, the region's energy stakeholders are urging it to cast a wide net and not commit to an approach too soon.

The grid operator in the last few weeks has said it's leaning toward a marginal approach to capacity accreditation, using a concept called Marginal Reliability Impact (MRI). That's in contrast to an average approach that accredits resources based on their share of their class's total reliability contribution. (See *ISO-NE Starts its Capacity Accreditation Journey*.)

At last week's NEPOOL Markets Committee meeting, Advanced Energy Economy warned ISO-NE not to rush into a decision, highlighting challenges with the marginal approach and advocating for broader consideration.

"Marginal accreditation is a novel approach and presents potential challenges as a replacement to the current capacity accreditation regime," AEE's Caitlin Marquis said in a *presentation* to the committee.

Among those challenges: It could result in different compensation to resources that provide the same total reliability benefit to the system and be more sensitive to accurate modeling of the region's resource mix.

Also, even though the marginal method is often cited as having clearer entry and exit signals for resources, Marquis said, accurate signals don't always facilitate efficient decisions if they're still highly variable.

"Average versus marginal is a significant decision that should not be rushed; before moving forward with marginal, we should fully consider challenges and address shortcomings," Marquis said in her presentation.

That could include exploring alternative or hybrid approaches, she said.

Also at the meeting, Ben Griffiths of LS Power raised concerns about the ability of a marginal accreditation method, which is an effective load-carrying capability (ELCC) measurement, to accurately measure the contributions of thermal resources.

"Proposals to apply ELCC-like accreditation mechanisms to thermal resources can obscure economic choices and may solidify the status quo by muting price signals," Griffiths said in his *presentation*.

ELCC works for variable renewables because their performance is mostly determined by factors outside their control, Griffiths said. That's not the case for thermal resources, which are more governed by economic conditions and operational choices, he argued.

The "class-based ELCC/MRI approach necessarily lumps good and poor performers into one class, which reduces downside risk for poor performers, and limits accreditation value for good ones," Griffiths said. A preferable approach would be to refine a unit-specific accreditation method like PJM's unforced capacity, which he said is a "reasonable starting point."

ISO-NE is still early in what will be a year-long-plus process of developing an update to capacity accreditation.

At the meeting last week, the RTO's Feng Zhao *put forward new details* about how its conceptual design for an MRI would work, with a promise of more design information to come in the next few months. ■

ISO-NE News

Conn. Lawmakers Push ISO-NE on Climate

By Sam Mintz

The Connecticut State Capitol in Hartford | *Shutterstock*

A group of Connecticut lawmakers urged ISO-NE last week to take action in the wake of the Supreme Court's June 30 ruling barring the EPA from requiring generation shifting to reduce carbon emissions. (See *Supreme Court Rejects EPA Generation Shifting*.)

In a *letter* to CEO Gordon van Welie, the legislators asked ISO-NE to "move more aggressively to adopt market reforms that will increase our reliance on renewable energy sources and establish carbon emission standards for power plants."

The letter is the latest development in the continuous back and forth between ISO-NE and the New England states over the right approach and appropriate jurisdiction for greening the region's electricity markets. (See *NE States, ISO-NE Start to Wrestle with Next Steps on Pathways*.)

The Connecticut lawmakers pointed to work they've already done as a state, such as power purchase agreements, and a region, such as the Regional Greenhouse Gas Initiative, but said it's not enough.

"The Supreme Court's decision puts the ISOs and RTOs in the driver's seat when it comes to shifting how this country procures energy," the letter says. "The time to act is now. And it is our hope that ISO-NE will be our partners in that process."

The letter was led by House Majority Leader Jason Rojas (D) and Energy and Technology Committee Chair David Arconti (D), with 44 other state representatives signing on. ■

MISO News

Invenergy Announces Grain Belt Express Expansion

By Amanda Durish Cook

Invenergy says it will increase the planned Grain Belt Express transmission line's capacity to deliver 25% more power than originally planned, but at an additional multibillion-dollar cost.

Chicago-based developer Invenergy Transmission said in a press release July 11 that it will increase the 800-mile HVDC Grain Belt Express' total capacity to 5 GW. It said the bump will deliver more energy cost savings to Missouri, Illinois and the Midwest. The expansion increases the project's investment to $7 billion, up from an estimated $2.5 billion earlier this year.

Missouri will see the largest delivery increases after the project's midpoint converter station is expanded from 500 MW to 2.5 GW. Invenergy plans to move the substation and add a 40-mile delivery line, dubbed the Grain Belt Express Tiger Connector.

Invenergy said the changes are necessary to reach an existing substation that is robust enough to handle large injections of power.

Using an analysis from PA Consulting Group, the developer estimates the beefed-up merchant line will save ratepayers in Missouri and Illinois a total $7.5 billion over 15 years. Kansas ratepayers are expected to realize a $1-billion savings over the same time frame.

Invenergy said it will pursue "all required regulatory approvals related to facility changes" and will hold an open house later this month to discuss Tiger Connector route options and seek input from landowners. The company said it is "committed to building transmission infrastructure the right way — treating landowners with respect and fairness."

The utility said that the line's route, right of way and facility design remains unchanged, and development will begin according to existing regulatory approvals.

Invenergy spokesperson Dia Kuykendall said the company plans to begin construction in 2024 and achieve commercial operations sometime in 2027.

"As families and businesses face rising costs and power grid operators sound the alarm about regional reliability challenges, Invenergy Transmission is proud to be delivering solutions," said Shashank Sane, Invenergy's executive vice president and head of transmission. "By increasing total power delivery for the Grain Belt Express and ensuring an equal share is available locally, this state-of-the-art transmission infrastructure project will save families and businesses billions of dollars in electric costs each year, protect our communities by improving reliability, and power prosperity across the Midwest well into the future."

The 800-mile transmission line is intended to carry wind power from western Kansas through Missouri and Illinois to the Indiana border. It has faced significant resistance in Missouri, which initially denied permits. (See *Invenergy Renewing Push for Grain Belt Express*.)

But things are looking up for the long-stalled project.

Last month, Missouri Governor Mike Parson signed legislation requiring line developers to pay landowners 150% of fair market value for land taken through eminent domain. The final House Bill 2005 was viewed as a compromise among Missouri lawmakers; it guarantees farmers more money for their parcels but doesn't require transmission developers to seek approval from individual county commissions for their lines.

Texas-based Clean Line Energy Partners first proposed construction of the Grain Belt Express in 2014 but was met with opposition, delay and litigation over eminent domain for the segment of line crossing Missouri. Invenergy acquired the project in 2019. A year later, disputes over the line's development reached the Missouri Supreme Court, which ruled that the Missouri regulators erred when they denied Grain Belt a certificate of convenience and necessity.

Illinois and Missouri business leaders applauded Invenergy's decision, including the Associated Industries of Missouri, the Illinois Manufacturers' Association and the Missouri Public Utility Alliance. They said the line stands to stimulate billions of dollars in economic activity in Illinois and Missouri and millions in "new taxes and revenue for local communities along the route."

"Grain Belt Express's additional commitment to deliver more power to Missouri could not have come at a better time for businesses in our region who are facing increased risk for outages and higher energy bills due to more demand and less energy production," Ray McCarty, CEO of Associated Industries of Missouri, said in a joint press release with his Illinois counterparts. "Bringing more power to the region is the best solution to manage this urgent challenge, and we thank Grain Belt Express for responding to those needs."

Illinois Manufacturers' Association CEO Mark Denzler said "manufacturers and the communities they support across our region will see significant benefits thanks to this essential investment."

"You can't have a strong business climate if manufacturers are worried about the reliability and cost of their power supply. There's no question," Denzler said. ■

Grain Belt Express project map | *Invenergy*

MISO News

Wisconsin Court Undercuts Lawsuit in Cardinal-Hickory Creek Dispute

Conservation Groups Vow to Continue Federal Battle over Project

By Amanda Durish Cook

The Wisconsin Supreme Court on July 7 ruled that a former state regulator's encrypted messages with power line developers did not amount to a serious risk of bias during the controversial Cardinal-Hickory Creek line's permitting process.

In a 4-3 *opinion*, the court's conservative majority undercut a lawsuit brought by conservation groups that challenged the line's permitting process before regulators in 2019. The court ruled that former Wisconsin Public Service Commissioner Mike Huebsch does not have to testify or turn over his phone after he used a software app to exchange covert messages with an American Transmission Co. (ATC) employee and a former independent contractor for ITC Midwest.

ATC and ITC Midwest, the project's co-owners, last year uncovered evidence of years' worth of encrypted messages between Huebsch and their employees. As a result, the companies redid the project's certificate of public convenience and necessity to avoid improprieties. (See *Former Wisc. Commissioner's Texts Imperil Cardinal-Hickory Creek Line*.)

The court kept its decision focused on Huebsch's conduct and didn't address the merits of the PSC's unanimous approval of the $500 million, 101-mile, 345-kV Cardinal-Hickory Creek line. It said Huebsch didn't violate the line's opponents' due process and rejected the conservation groups' subpoena for an inspection of Huebsch's cellphone.

The court also said a lower court erred when it rejected Huebsch's motion to quash the subpoena. It remanded the case back to the Dane County Circuit Court.

Penning the majority's opinion, Chief Justice Patience Roggensack said the Driftless Area Land Conservancy (DALC) "allegations of bias do not come close to the level of alleging a cognizable due process claim." The high court described the accusations of bias against Huebsch as "meritless," based on "absolutely no factual evidence" and "borderline frivolous." It said that public servants are presumed impartial unless there's solid evidence to the contrary.

Conservative justices also said that the nation needs strengthened interstate transmission and said Cardinal-Hickory Creek enjoys "widespread support from labor, industry, business groups, environmentalists, Republicans and Democrats."

Howard Learner, executive director of the Environmental Law and Policy Center, represents conservation groups DALC and the Wisconsin Wildlife Federation in the fight against the line. He said he was disappointed that the state supreme court "overreached in holding that Wisconsin law prevents conservation and consumer groups from taking discovery into the hundreds of phone calls, secret text messages, lunches, dinners and golf dates between … Huebsch and senior executives for the transmission companies that proposed this costly high-voltage transmission line."

"Allowing these kinds of improper communications without any recourse under state law undermines public confidence in the fairness and integrity of Wisconsin's utility regulatory process," he said in an emailed statement to *RTO Insider*.

Learner said he agreed with the court's liberal minority and said the four conservative justices "bent the judicial rules to provide special treatment in protecting improper conduct by their political ally."

The liberal justices wrote in a dissent that "if our government is truly one of laws and not men and women, then we cannot use extraordinary constitutional powers to carve out special treatment for ourselves and only persons like us." They said the majority justices' "indulgence in the excesses of judicial power is not grounded in law and serves only to deepen inequalities in our system of justice."

ATC and ITC issued a statement saying they appreciated the Supreme Court's "thoughtful decision." They celebrated the end of a "contrived fishing expedition that the project's opponents orchestrated against former Commissioner Huebsch."

"With the case now remanded back to the Dane County Circuit Court, the co-owners look forward to successfully concluding the litigation on the merits of the Public Service Commission of Wisconsin's September 2019 decision to approve the project," ATC and ITC said in an emailed statement.

Huebsch's attorney Ryan Walsh *told* Wisconsin Public Radio that the ruling makes clear that there "shouldn't be fact-finding into the personal lives of judges and judicators without rock-solid evidence that something inappropriate has happened." Walsh said the decision ended a yearslong "cloud" hanging over his client.

The Upper Mississippi River National Wildlife and Fish Refuge | *U.S. Fish and Wildlife Service*

Learner pointed out that the line is still set to cut through a protected wildlife refuge. A federal judge earlier this year blocked construction of the line through Upper Mississippi River National Fish and Wildlife Refuge. (See *Federal Judge: Tx Line Can't Cross Wildlife Refuge*.)

ATC and ITC are appealing that decision before an appeals panel this fall. In the meantime, the companies continue to clear-cut the original route up to the protected refuge area. ATC and ITC report that they have nearly completed a segment in Iowa and are continuing construction in western Wisconsin.

With the matter of Huebsch's texts decided at the state level, the DALC vowed to continue the fight against the project at the federal level.

Learner said a "fair review of the evidence will show that there are better, more cost-effective, more environmentally sound, and more flexible alternatives for reliable clean energy in the Wisconsin Driftless Area."

ATC and ITC estimate that 127 renewable generation projects comprising about 19 GW of capacity are currently dependent on the line's completion.

"Utilities across our region are depending on the Cardinal-Hickory Creek project to facilitate the region's transition away from fossil fuels and support decarbonization goals," the companies said. "The critical role of this project in meeting the region's energy needs compels the co-owners to ensure it is built for the benefit of electric consumers by the scheduled in-service date of December 2023."

The Cardinal-Hickory Creek line is the last of MISO's $6.7 billion, 17-project Multi-Value Project *portfolio* approved in 2011. ■

MISO Defends 2030 Completion for DER Market Participation

By Amanda Durish Cook

Petersburg Solar Project | *AES Indiana*

MISO is insisting to FERC that it's appropriate to take until 2030 before beginning the complicated task of opening its markets to distributed energy resource aggregators.

The grid operator filed a defense of its Order 2222 compliance plan with the commission July 8, calling its proposed effective dates for registration (October 2029) and aggregations' market participation (March 2030) "reasonable and appropriately tailored for the MISO region." (See *MISO Finalizes Plan for DER Market Participation in 2030*.)

This comes after several members, state regulators and stakeholders said they were perplexed as to why MISO couldn't accept DER aggregations after it replaces its market platform in 2024 or 2025. (See *MISO Stakeholders Protest RTO's Order 2222 Implementation Timeline*.)

The RTO reminded FERC that its Order 2222 "recognized regional differences and directed each ISO/RTO to propose an implementation timeline that is reasonable for its respective markets" (*ER22-1640*).

Responding to the Organization of MISO States' criticism that its plan is too drawn out, MISO said regulators can encourage participation in existing retail DER programs. The grid operator said retail regulatory authorities "have both the ability and authority to further develop and promote these programs" while MISO develops the systems and software necessary to implement Order 2222's requirements.

MISO contended the "time between now and 2029 will be best used to work on other market and underlying system enhancements that it believes will make the full DER implementation process seamless and able to provide the most value."

It also addressed arguments from clean energy and solar trade associations that the lengthy delivery time is tantamount to seeking a waiver of FERC compliance obligations. The RTO said that in addition to completing its market platform replacement, it needs another four years to overhaul its registration and enrollment system that is more than 10 years old. It also explained it must first introduce a multi-configuration resource participation model before it can tackle offers from DER aggregations.

MISO plans to use elements of its electric storage participation plan for DER aggregations. The aggregations must self-commit in the RTO's markets based on their own forecasts and will be limited to a single pricing node. ■

MISO News

DC Circuit Court Backs FERC over MISO Interregional Cost Allocation

By Amanda Durish Cook

The D.C. Circuit Court of Appeals on Friday sided with FERC over Entergy Arkansas in a disagreement concerning MISO's cost allocation for interregional transmission projects with other RTOs.

The court rejected Entergy's appeal and kept the current cost allocation in place for MISO's share of interregional projects rated from 100 to 345 kV. The ruling supports FERC's decisions to allow cost recovery of lower voltage transmission projects beyond the pricing zone in which they are located (*20-1262*).

MISO's portion of its interregional market efficiency projects (MEPs) with PJM and SPP are divvied up based on an adjusted production cost savings calculation that finds benefits beyond a project's own zonal borders. MISO and SPP have never approved an interregional MEP, but MISO and PJM have.

Entergy argued that power flows are different between lower and higher voltage projects, making the benefits of lower-voltage projects limited and locally concentrated.

Entergy also argued the commission was incorrect to refuse a 2019 MISO proposal that limited the cost recovery of projects under 230 kV to the transmission pricing zone they are located in. It said FERC's substitute solution based on adjusted production costs savings was inadequate.

But the court, quoting a previous return-on-equity case, noted that "FERC is not required to choose the best solution, only a reasonable one."

"It is not our job to determine that 'FERC made the better call,' rather, our 'important but limited role is to ensure that the Commission engaged in reasoned decision-making — that it weighed competing views, selected a ... formula with adequate support in the record and intelligibly explained the reasons for making that choice,'" the court wrote, citing 2016's *FERC v. Electric Power Supply Ass'n* Supreme Court ruling.

The court also pointed out that MISO is still free to propose a different cost allocation for FERC's review.

The commission twice rejected MISO's cost-sharing design for interregional MEPs before directing the grid operator in 2019 to use a design based on adjusted production costs savings for economic interregional projects 100 kV and above. (See *Another Rejection for MISO Cost Allocation Plan*.)

The back-and-forth at the time was because of MISO and PJM approving their first major interregional transmission project. MISO said that because a $22 million reconstruction of the Michigan City-Trail Creek-Bosserman line in Indiana was only a 138-kV project, it could not allocate costs beyond the transmission pricing zone where the grid operator's share of the project was located.

MISO currently has a FERC-sanctioned mismatch between the voltage thresholds it uses for its regional and interregional MEPs. The RTO uses a 230-kV threshold for MEPS in its footprint and relegates lower voltage projects to an "other" category, where they're ineligible for cost recovery from multiple pricing zones. (See *MISO Cost Allocation Plan Wins OK on 3rd Round*.)

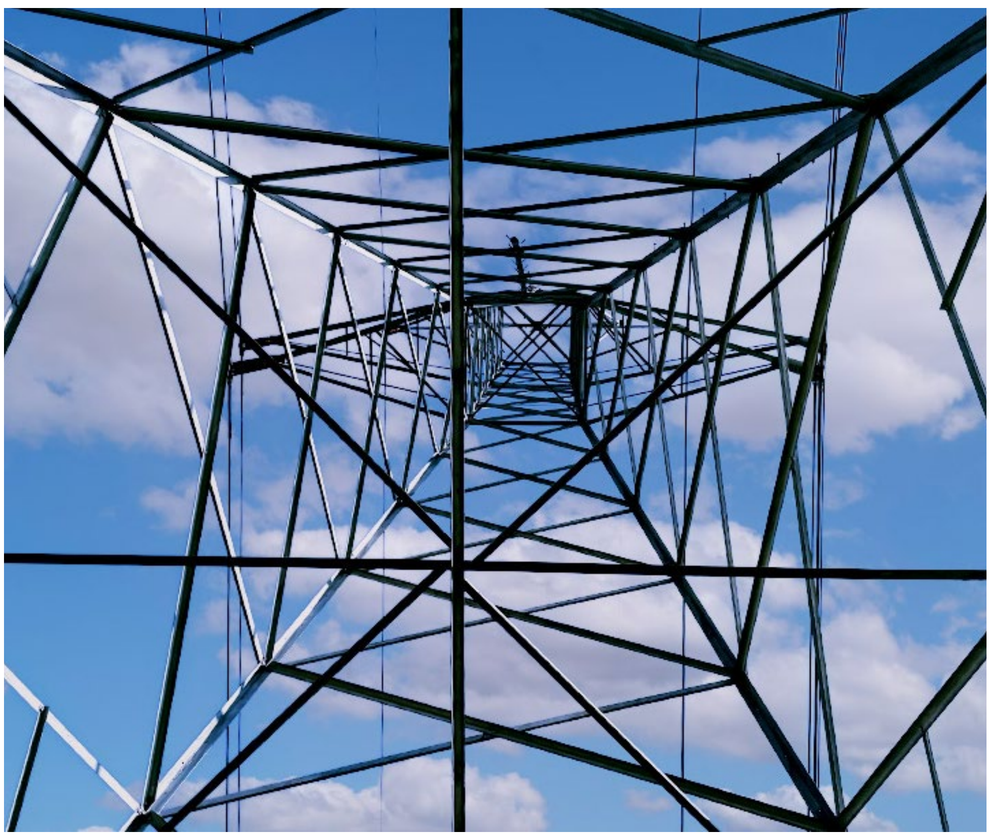
In 2016, FERC lowered MISO's interregional economic project voltage threshold from 345 kV to 100 kV after a 2013 complaint before the commission by Northern Indiana Public Service Co. over the MISO-PJM interregional planning process.

The Circuit Court's agreement that lower-voltage transmission projects can deliver benefits regionally might have implications for other past cost-allocation decisions on MISO MEPs.

The commission has repeatedly refused to entertain competitive developer LS Power's argument for a lower voltage threshold on economic transmission projects in the MISO footprint (*EL19-79*; *ER20-1723-001*). (See *FERC Spurns LS Power's Voltage Threshold Argument*.)

LS Power has tried for two years to persuade FERC that the RTO should use a 100-kV threshold for market efficiency projects instead of the 230-kV cutoff the RTO was cleared to use in mid-2020. The company has contended that MISO's 230-kV threshold is arbitrary because projects with voltages down to 100 kV can deliver significant regional benefits.

FERC has held firm that small, regionally beneficial projects are the exception, not the rule, and do not justify opening more projects to competitive bidding. ■



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MISO News

MISO Predicts Easier Operations in Fall

By Amanda Durish Cook

As it navigates a tough summer, MISO is more optimistic about successfully managing operations this fall.

The grid operator on Thursday *released* a fall resource adequacy outlook, where it said it shouldn't encounter trouble if demand and generation outages remain at normal levels throughout autumn.

Using a probable peak load forecast, MISO expects to have 114 GW of firm resources on hand to cover a projected 111-GW peak in September; 100 GW available to manage a 92-GW peak in October; and 104 GW by the time November's expected peak demand of 91 GW rolls around.

Still, September's skimpy surplus means the RTO is not ruling out the possibility of emergency actions. The National Oceanic and Atmospheric Administration has said almost the entire MISO footprint should see a warmer-than-normal fall.

The grid operator said a high-outage scenario in September could possibly completely exhaust the 10.3 GW cushion of emergency operating reserves and load reduction. MISO said a higher-than-expected load of 117.5 GW could outstrip its fleet if only 104.3-GW of firm resources are available.

The RTO also said it might declare an emergency to dip into load-modifying resources in a worst-case scenario in October, when high outage rates could make only 95.3 GW of non-emergency resources available and demand surges to 97.5 GW.

MISO typically experiences 34.5 GW worth of generation outages in the fall, with about 11 GW of that forced. The RTO's all-time fall peak load of 115 GW occurred in September 2017.

Summer Woes Still Top of Mind

Most of the MISO community's attention remains on the summer heat and how much worse it could be this time next year.

During a Market Subcommittee meeting Thursday, Independent Market Monitor David Patton said there may be cause for "heightened concern" next summer. He said he anticipates about 1.4 GW of generation heading into retirement between now and next year.

Patton continues to insist MISO isn't communicating all risk in its pre-season summer assessments, failing to account for generation derates during heat waves.

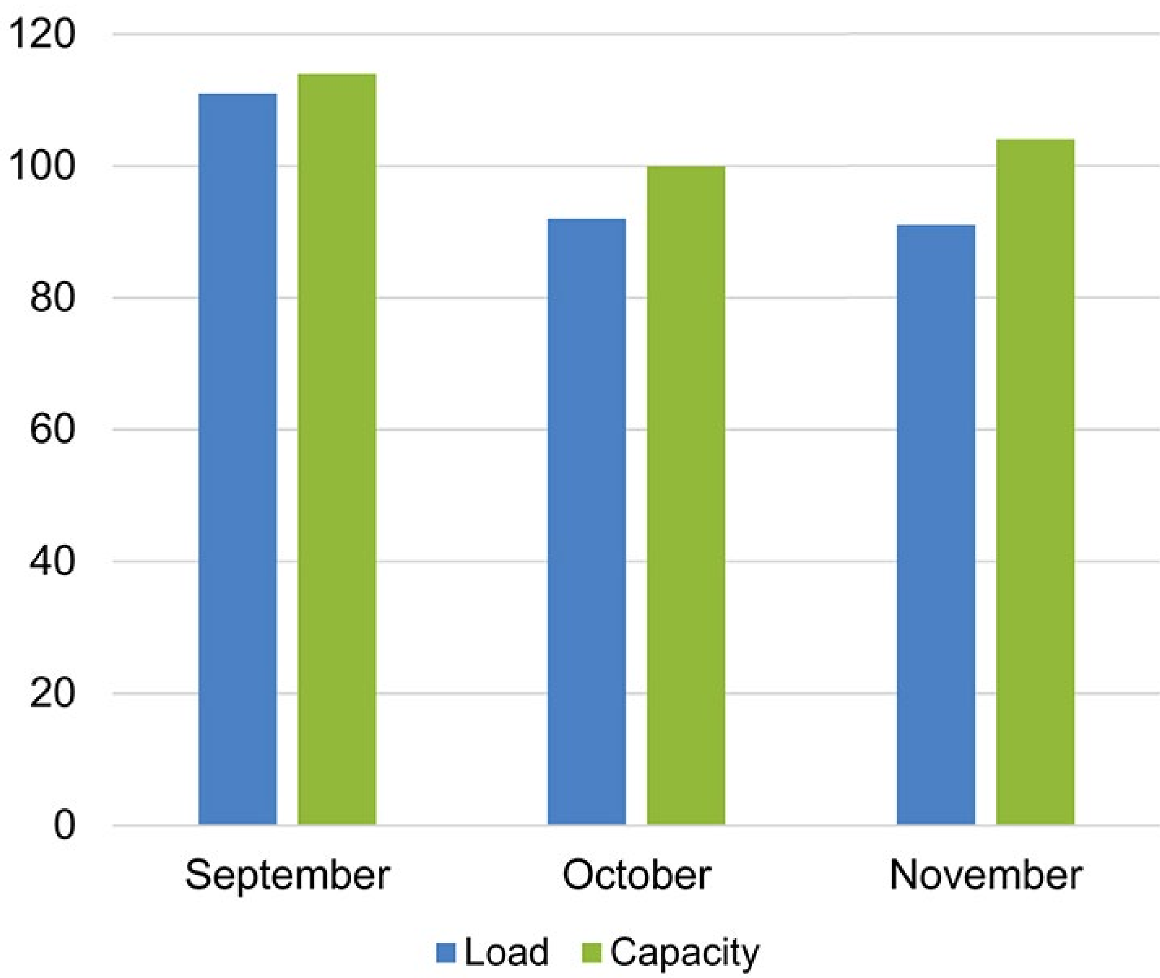
"As temperatures get hotter and hotter, the generating capacity of our thermal generation tends to go down," he said.

Stakeholders asked how MISO can avoid ERCOT's fate of never-ending warnings of summertime energy conservation. (See *ERCOT Dances with Danger Again*.)

"You don't want to be ERCOT," Patton said before adding, "Not to put too fine a point on it, but I've been telling MISO for ten years now that you're going to have a resource adequacy problem."

Patton said MISO needs a sloped demand curve in its capacity auction to produce "reasonable" and not "close to zero" prices, allowing some resource owners to make enough money to stave off retirement.

"We haven't done it, and we've needed it. And now I think we'll do it," he said of the demand curve changes. "It's not rocket science." ■



MISO likely fall load and available capacity by month | *MISO*

MISO News

MISO Promises Stakeholder Discussions on Capacity Auction Reform

By Amanda Durish Cook

Great River Energy's natural gas-fired Cambridge Station in Minnesota | *GRE*

MISO leadership last week committed to holding future talks with stakeholders on how to retool its capacity auction to stimulate more supply.

Scott Wright, the RTO's executive director of market strategy, said the growing reliability risk will require staff and stakeholders to discuss modifications to price signals and how to value resources' different attributes in the capacity market.

The discussions will be held in the Resource Adequacy (RASC) and Market subcommittees during the next few months, Wright said. He added that the conversations will likely include potentially adding a sloped demand curve in the capacity auction. (See *MISO Warming to Patton's Sloped Demand Curve*.)

"MISO is committed to coordinated action and is developing plans for near-term evaluation and stakeholder engagement," Wright told stakeholders during a Resource Adequacy Subcommittee meeting Wednesday. "We're not deferring this to next year; we want to get going this year."

The vow was repeated the next day during a Market Subcommittee meeting.

"We're looking through what the plan is and will return to these forums," MISO Senior Director of Transmission Planning Laura Rauch said.

Independent Market Monitor David Patton said after speaking with state regulators following the April planning resource auction (PRA), he's "cautiously optimistic" that MISO will be on a path to applying a sloped demand curve within six months

"The best time to implement a sloped demand would have been when you're not in shortage," he said.

MISO Midwest is grappling with a 1.2-GW capacity shortage following the 2022-23 PRA. The shortfall triggered a $236.66/MW-day cost-of-new-generation-entry clearing-price for the Midwestern subregion. MISO has said the deficit might force it to order temporary, controlled load sheds this summer and next as it is not expecting sufficient firm resources to handle summer peak forecasts under typical demand. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

Though members approached this year's auction with more capacity year-over-year, staff said the resource additions were mostly intermittent and generally less available than retiring thermal generators.

Stakeholders Ask for Data Improvements

Constellation Energy's John Orr said staff's posting of preliminary supply and demand data for the PRA could use some improvements and more regular updating.

Orr suggested MISO implement a standardized timeline for posting forecasted capacity positions by local resource zone, perhaps releasing the data in January and updating it on a weekly basis as market participants update capacity values. He said MISO should periodically update how much capacity has been converted to zonal resource credits. He said if a particular zone returns a zero value ahead of the auction, that could spur members into making arrangements to avoid another capacity shortfall.

Orr said a weakness of MISO's 2022-23 preliminary data was that it was never updated beyond a singular release.

"We all knew those numbers are incomplete, but they gave us an idea of what to expect, especially in zones that are predicted to be tight," Orr said. He, like other stakeholders, questioned why they failed to warn of a potential shortage.

Orr said he thinks "it's time for stakeholders to ask MISO what they want to see" and asked stakeholders to work together to develop recommendations to MISO.

He said market participants need a better idea of what resources are expected to be unavailable, either due to retirements or auction exemptions and exclusions approved by the IMM.

"The exemptions and retirements that are protected by confidentially can really kind of can throw you off when you're going to be very tight, as it appears we're going to be for the next several PRA cycles. And the seasonal auctions could throw another wrinkle in that," Orr said.

WEC Energy Group's Chris Plante said his utility is having "a lot of difficulty" preparing quadrupled data for a yet-uncertain seasonal capacity auction. FERC has yet to approve MISO's request to conduct four seasonal auctions per year.

In the meantime, MISO leadership continues to issue grim warnings over its forecasted capacity supplies.

During a July 7 meeting with Kentucky lawmakers, Melissa Seymour, vice president of external affairs, said that part of the state might face controlled load shedding next year.

Seymour delivered a similar message in front of the Illinois Commerce Commission in May. (See *MISO Exec, IMM Debate Next Steps After Capacity Auction Shortfall*.)

"Unless more capacity is built or bought, especially capacity able to reliably generate during tight system conditions, the shortfalls we experience this year will continue and get worse going forward," she said.

MISO's wholesale footprint affects just 14% of Kentucky's retail power sales.

Seymour's comments led Kentucky lawmakers to suggest ramping up coal production, delaying coal plant retirements, and even bringing some nonoperational coal plants out of retirement.

According to its pending 2021 *integrated resource plan*, Louisville Gas and Electric and Kentucky Utilities intend to retire a dozen aging coal and gas-fired units from 2024 to 2036.

"As a generation unit ages, the economics of retrofitting the unit to comply with new environmental regulations become less favorable," LGE and KU explained in the filing. However, the utilities still plan to burn coal into 2066.

New Accreditation for Renewables in the Works

MISO continues to evaluate new capacity accreditation designs with stakeholders for the footprint's renewable resources and load-modifying resources.

During the July RASC meeting, the RTO's director of policy studies, Jordan Bakke, said staff and stakeholders are "learning together" about accreditation options for non-thermal generation. He said MISO is still in an evaluation stage and hasn't internally settled on an option.

Patton said once MISO more accurately accredits intermittent resources, it should send economic signals to developers to pair their renewable energy with battery storage. He said co-located renewable and storage hybrid resources will likely have a much higher capacity credit.

MISO laid out three potential options this spring to accredit renewable resources: expand its effective load carrying capability (ELCC) calculation to include solar as well as wind; use the same performance-based accreditation design that it proposed for its thermal generation and currently pending before FERC; or use a blend of ELCC and performance-driven accreditation.

Some stakeholders expressed confusion with how the blended option would be handled.

Staff said they would use its projected loss-of-load risk hours and MISO's new concept of "resource adequacy hours" — the historical tight margin and emergency periods defined for the performance-based accreditation design — as possible inputs for the new accreditation method. (See *MISO Stakeholders Insist on Consistency in Capacity Accreditations*.)

The RTO filed with *FERC* late last year to change its accreditation for conventional resources to a seasonal value based on a unit's past performance during resource adequacy hours. The new accreditation is contained in a larger filing to create four seasonal capacity auctions. (See *Deficiency Notices for MISO's Seasonal Capacity Auctions Bid*.)

The grid operator said the blended approach for renewables has the potential to encompass a "broader range of planning and operational considerations." Staff said loss-of-load hours and resource adequacy hours don't necessarily occur on the same days.

MISO plans to discuss a new accreditation method for its non-thermal resources in RASC meetings and special workshops through the end of the year. ■

NYISO News

Stakeholders Question Feasibility, Costs of Con Ed OSW Substation

By Michael Kuser

Stakeholders last week urged New York regulators to defer approval, outright reject or refer to NYISO's public policy transmission planning process Consolidated Edison's *proposal* for a new substation in Brooklyn to integrate up to 6 GW of offshore wind energy (*20-E-0197*).

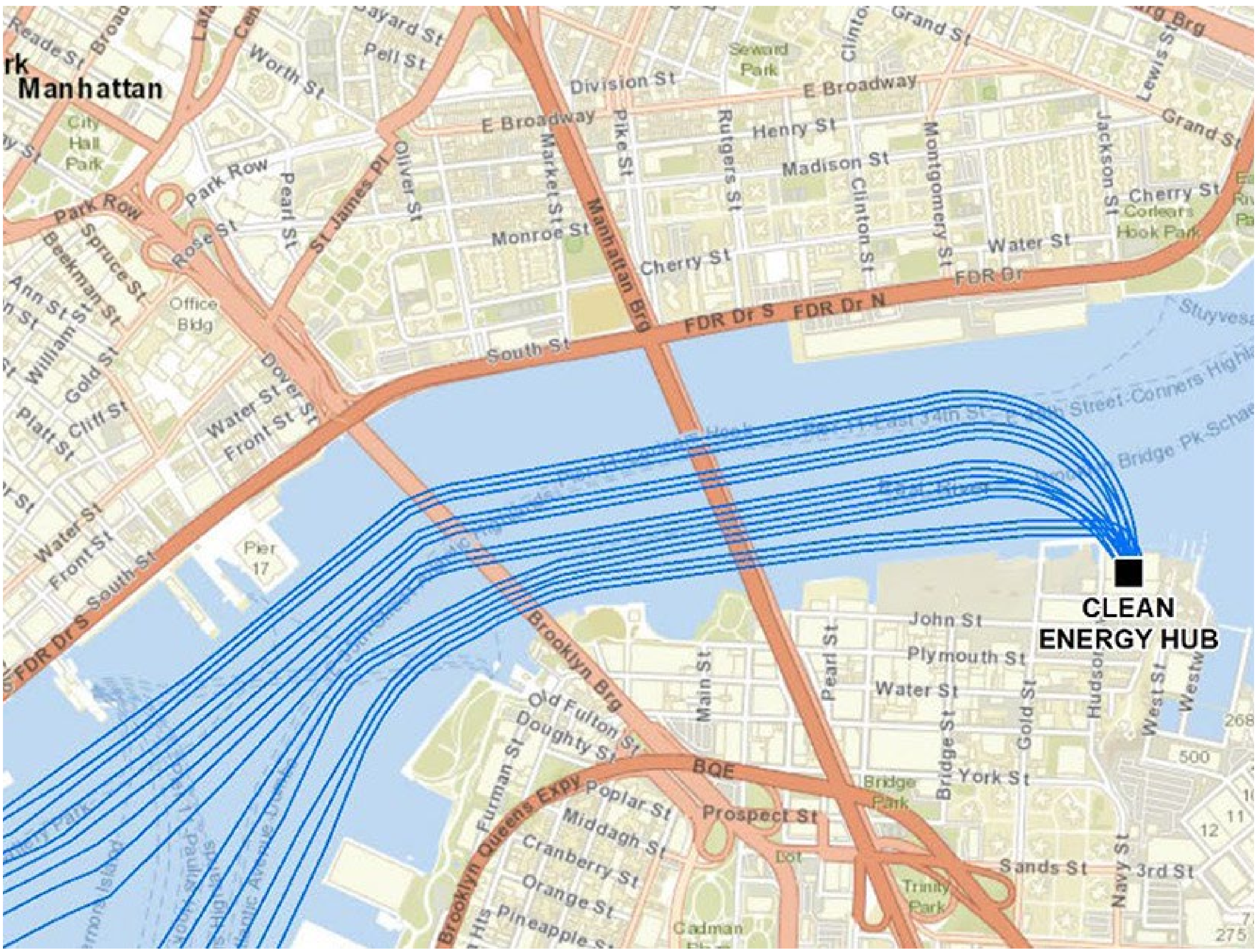
The utility would build the Brooklyn Clean Energy Hub on land it already owns adjacent to its Farragut Substation on the East River waterfront, a move it claims would save time and money, and also reduce interconnection costs compared to alternatives.

Stakeholders claimed that Con Ed's proposal was long on optimism and short on details; complicated risk assessment for offshore wind developers preparing to respond to an imminent state solicitation; and should go through a competitive bidding process.

The Long Island Power Authority (LIPA) *said* that Con Ed's April petition did not address the Public Service Commission's January *order* that the utility provide specific information regarding why its existing substations cannot accommodate future offshore wind projects.

"The petition discussed and rejected a few alternative points of interconnection (Gowanus and Staten Island) but did not provide a comprehensive review of alternative points of interconnection (POIs) with associated cost estimates. Although the petition discussed the addition of a feeder and ring bus costs as being time- and cost-prohibitive elements associated with transmission interconnection at Gowanus, it provided few details associated with this analysis," LIPA said.

In addition, NYISO's Long Island OSW export public policy transmission need (PPTN) *solicitation* process is nearly complete and may result in a solution that itself creates interconnection headroom, thereby possibly reducing the need for the new hub. "The commission, therefore, should consider deferring its approval of costs



NEETNY claims that standard industry cable spacing would likely allow a maximum of five cables in the approximately 650-foot wide part of the East River near the Manhattan Bridge. | *NextEra*

NYISO News

of this magnitude until a PPTN proposal is selected," LIPA said.

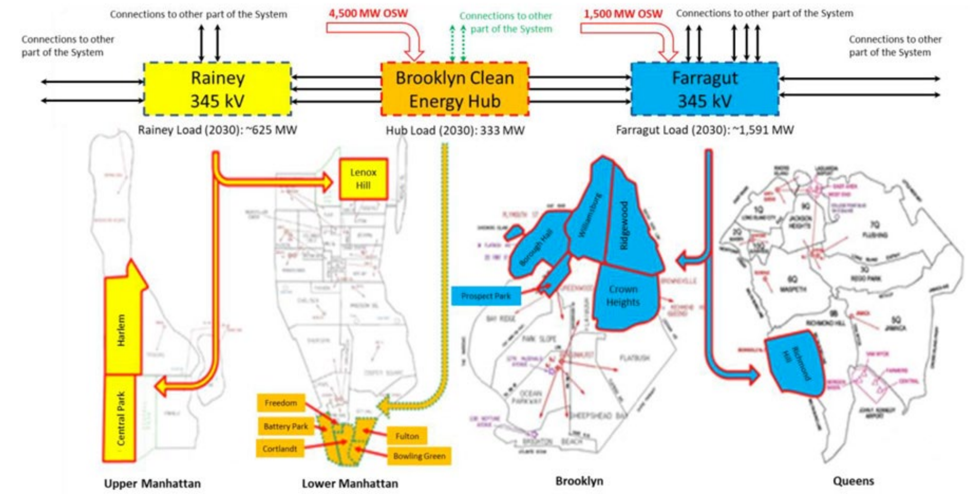
LS Power Grid and NextEra Energy Transmission New York reiterated calls for the PSC to refer Con Ed's hub proposal to the NYISO planning process as a regional transmission project, calls that the commission rejected in its January order. (See *NYPSC Mandates Meshed Offshore Tx Grids*.)

While agreeing that the commission has significant authority over planning and siting, the NYISO competitive process nonetheless "is a powerful tool to achieve the goal of meeting [state] mandates at the least cost to ratepayers," LS Power *said*.

The project as proposed by Con Ed is infeasible and presents significant challenges for OSW developers to permit and construct the necessary transmission lines, *said* NextEra.

"Con Edison assumes that OSW developers would utilize HVDC cables to reduce the number of cables required under the Verrazzano-Narrows Bridge and will site multiple converter stations near the water in New Jersey, Staten Island and/or Brooklyn. However, under Con Edison's assumed scenario, the OSW developers would be required to install up to three HVAC cables from each converter station to connect to the hub project. Moreover, Con Edison assumes that the HVAC cables will connect to the hub project by water," NextEra said.

To accommodate 6,000 MW of OSW generation, five HVDC and 15 HVAC cables will need to be installed in the Upper Bay; that many cables, as well as the requirement to site and install converter stations near the water as Con Ed has proposed, presents significant coordination, permitting and construction challenges, NextEra said.



Inclusion of the Brooklyn Clean Energy Hub within Con Edison's 345-kV system | *Con Edison*

"Independent developers should not be ignored in considering the Clean Energy Hub and its many surrounding implications," *said* Anbaric Development Partners.

Questioning the merits of interconnecting 4,500 to 6,000 MW of offshore wind "at essentially a single location," New York City *said* that a climatic or other extreme event at that location could sever all of the offshore wind connections to the city, perhaps for an extended period of time.

As the state and city become more reliant on renewable resources and shut down its remaining fossil plants, a single interconnection location in Brooklyn for most offshore wind projects "could create unacceptable reliability and resilience risks," the city said.

Con Ed also "creates a false sense of urgency" to support expedited approval of its petition, claiming the project is the only one that can be in service by 2027, LS Power said.

Comparative Interconnection Cost	Project Size (MW)	Cost ($/MW) Proposed Projects*	Cost ($/MW) Brooklyn Clean Energy Hub**	Relative Cost Effectiveness
Low	1,000	$242,153	$166,667	1.45
Medium	1,172	$332,744		2.00
High	258	$1,216,153		7.30
Weighted Average		$389,257		2.34

**Low is CHPE: Astoria Annex 345kV, Medium is North Bergen Liberty: W49th St. 345kV and High is Ravenswood ESS: GIS Intercepting Farragut-Rainey 345kV based on 2019 NYISO Class Year Study*
***Brooklyn Clean Energy Hub: $1,000M / 6,000 MW of POI's = $166,667/MW. Any additional interconnection costs (e.g., breakers, NYISO fees, etc.) are de-minimis.*

The table lists NYISO published costs of interconnection for major generation facilities as compared to the Brooklyn Clean Energy Hub. | *Con Edison*

Even if the project could be completed by 2027, which is far from certain, there would not be anything to connect to it in that year. Rather, an OSW generator selected in the upcoming New York State Energy Research and Development Authority (NYSERDA) solicitation will most likely not be in service until after 2030, LS Power said.

The New York Offshore Wind Alliance (NYOWA) *said* the commission should initiate a competitive procurement that examines the costs and benefits of a wider set of solutions, which should run in parallel with the third NYSERDA OREC solicitation, scheduled to be released imminently.

Developers preparing for the upcoming solicitation have been working to identify and de-risk interconnection options, and those efforts should not be overridden, NYOWA said.

Con Ed identified the site of the Hudson Avenue Units 3, 4 and 5 for the location of the project. LIPA said the company did not provide any comparative costs for using other in-city POI "that could be vacated by existing merchant steam plants at Astoria and Ravenswood, upon their future retirement. Consequently, the PSC's decision would benefit from additional analysis as to whether alternative sites can be economically repurposed to interconnect offshore wind."

LIPA also encouraged the commission to consider the risk of potential cost overruns, quoting Con Ed calling the new substation "a conceptual project that will require detailed engineering studies." While the PSC requested an engineering cost estimate for the hub proposal, Con Ed provided no details about the studies behind or confidence level in the $1 billion cost estimate, LIPA said. ■

NYISO News

NYPSC Approves EV Charging Incentives, Climate-related Tx Projects

By Michael Kuser

The New York Public Service Commission on Thursday approved electric vehicle charging programs for the state's investor-owned utilities, enabling electrification of transportation with minimum upgrades to the grid (*18-E-0138*).

The state's EV Make-Ready initiative directed the utilities to develop managed charging programs that provide customers an alternative to home time-of-use rates.

"A one-size-fits-all approach isn't going to meet the diverse needs of the drivers and transportation providers in New York state," PSC Chair Rory Christian said. "The mix of passive and active programs was made possible through some foundational investments ... by utilities to deploy smart meters to collect more granular customer data. I look forward to reviewing the progress overtime that these utilities will make and seeing how the programs evolve to meet our customer needs."

The commission also approved modifying the EV rules for Consolidated Edison to allow the utility to increase the current single-site plug limit on fast-charging stations from 10 plugs to 30 and eliminate the funding limit on certain incentives.

"In terms of EV charging writ large, there's a right way to do this, and there's a wrong way to do this," Commissioner John Howard said. "This commission for decades as a matter of policy has asked, 'How do we reduce the peak?' The peak is difficult and it's enormously expensive to maintain, so the idea of moving as much [load] as we can, particularly in the early stages of electrification, to off-peak use is the only logical way to go forward."

Transmission Upgrades

The commission also approved nearly $700 million for National Grid to develop 26 transmission upgrade projects in support of the state's Climate Leadership and Community Protection Act (CLCPA). It was the first utility petition driven by the Accelerated Renewable Energy Growth and Community Benefit Act (*20-E-0197*).

The PSC categorized transmission projects that satisfy traditional reliability purposes and also address bottlenecks or constraints that limit the deliverability of renewable energy as phase 1, while phase 2 projects comprise upgrades that are needed solely to support CLCPA objectives.

The transmission projects for National Grid subsidiary Niagara Mohawk Power include substation equipment capacity upgrades, installation of larger transformers, rebuilds of existing transmission lines and installation of a dynamic line rating system to allow higher capacity operation during certain times. While 19 projects are relatively small and total about $38 million, seven other projects are more involved, such as the rebuild of century-old 115-kV lines — notably 126 miles of parallel lines in the Mohawk Valley from Little Falls to Schenectady.

The New York Public Service Commission on July 14 conducted its regular monthly session both in person and via teleconference. | *NYDPS*

"These items are here as a direct result of the directive of the Accelerated Renewable Energy Growth Act, and the investments identified will serve to do just that: accelerate the deployment and growth of renewable energy," Christian said. "Once complete, the need to curtail existing renewable energy resources will be diminished while making room to add additional renewable resources to the grid, and as an added bonus, this will reduce congestion in the overall transmission system and improve reliability to customers throughout the region."

Commissioner Diane Burman voted against the proposal, saying she was concerned that the commission had just this year approved a three-year rate plan for National Grid.

"I have real concerns about how rigorously the accounting for today's projects will be kept separate from the accounting for the rate case projects," Burman said. "I have concerns with how the company may reprioritize funding among both sets and whether that is truly coming before us. That action can have detrimental results on ratepayers if not done right."

Elizabeth Grisaru, deputy director of the Department of Public Service's Office of Electric Gas and Water, described the treatment of these projects as part of "a narrow exception" to the rule established for phase 1 projects.

"They were not required to identify local transmission investments that contributed to CLCPA guideline deadlines; it was not part of their planning obligation prior to February 2021, and I think that's probably why in the mix of capital programs that were part of the last National Grid rate case, these projects were not there because planning for CLCPA investment was not a component of the utilities' planning obligation before that date," Grisaru said.

Howard said that while there's enough regulatory assets to pay for the Niagara Mohawk upgrades, "this is not done in a vacuum. We still have Tier I expenses coming in; we have Tier III, Tier IV, phase 2 expenses that we don't know what they are. We have potential offshore wind integration, dealing particularly with a very large billion-dollar project in New York City. These things sound modest, but don't think that that's all you're going to pay for transmission, because there's a lot of other money that the customers will have to pony up to make these capital expenses." (See *Stakeholders Question CLCPA Pace and Costs for New York*.) ■

Residents Voice Opposition to Upstate NY Wind Project Before PSC

By Michael Kuser

Residents opposed to the Heritage Wind project planned for western New York spoke before the Public Service Commission on Thursday, citing human health concerns, danger to migratory birds in nearby game refuges and a lack of transmission capacity (22-E-0204 and 16-F-0546).

The developers "maintain that there will be no change in property value in our area. We would have six of the wind turbines almost 600 feet tall within 1 mile of our home and the fact that they tried to maintain that there would be no effect on our property value or anyone else's property value in this area I think is considerably a falsehood," Iva McKenna — a resident of Barre, where the project is to be located — told the PSC.

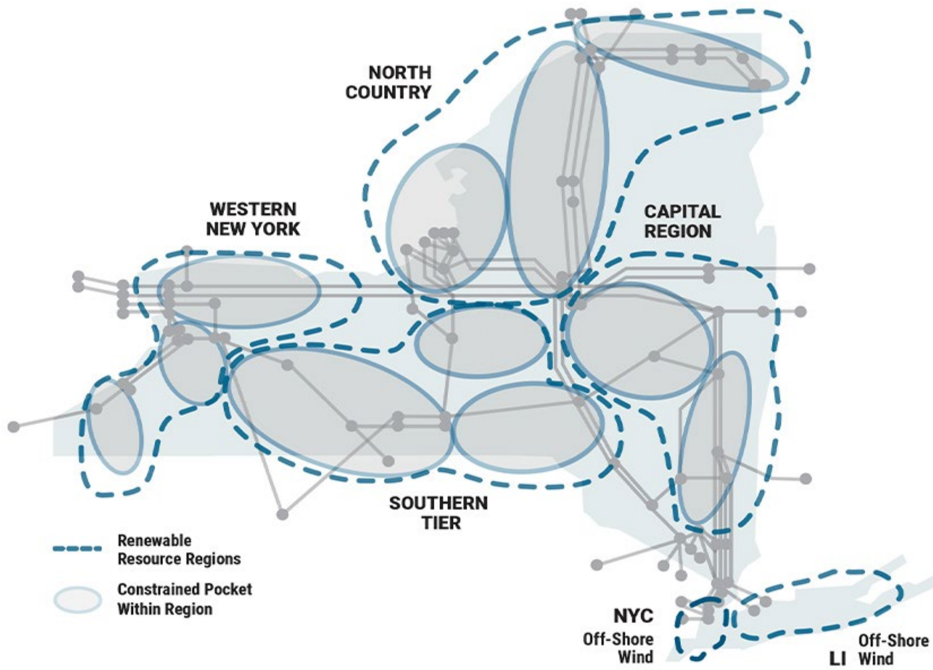
While only five people spoke at the hearing, all against the project, the initial proceeding drew 452 written comments, which were overwhelmingly opposed to the project, though about two-thirds of the total was form letters.

Only three of the 17 written comments submitted for the public hearing were in support. Austin Kuntz, union representative for Rochester-based Laborers' Local 435, said the project will bring hundreds of prevailing-wage jobs to local residents, provide them and their families with health care benefits and a suitable retirement, and fund schools, public services and infrastructure without the need to raise local taxes.

The Office of Renewable Energy Siting (ORES) in January granted a construction permit for the project in Barre, between Rochester and Niagara Falls, contingent on securing a certificate of public convenience and necessity from the PSC. The project is owned by Virginia-based Apex Clean Energy, which manages 2 GW of renewable energy.

Barre resident Adrienne Daniels commented on July 1 that her seizure disorder "very likely will be further affected by the towers' flicker effects. ... The proposed heights of the towers are ludicrous. It has to cause problems with airspace for the small airport nearby, bird populations, migration routes, etc. An eagle has nested on my property; I strongly doubt we'll have any other large birds establishing nests in this area."

With 4,607 gravel truck trips projected, resident Georgette Stockman said that if "they plan to use Route 77, will the movement of equipment and components pass the new Western New York Veterans Cemetery, where two people have already lost their lives trying to negotiate their way onto Route 77? Will the equipment go through the Iroquois Wildlife Refuge and disturb the very nature of a refuge?"



NYISO analysis identified transmission-constrained renewable generation pockets, as well as the levels of renewable generation curtailments that would occur within each pocket. | *NYISO*

Barre resident George McKenna reiterated his written concerns that the $198 million to be paid by NYSERDA for the project was "a wash" and that it would take at least 20 years to get that sum back in electrical energy value.

He also said Barre citizens have never had their opinions or concerns listened to.

"Surveys have shown approximately 70% of the population in opposition, and when the town board was in the process of changing the town's wind ordinance to accommodate Heritage Wind, 87% of the population was opposed," McKenna said.

Resident Kerri Richardson spoke of the inability of the transmission system to deliver increasing amounts of upstate renewables to downstate consumers and how that situation jeopardizes achieving the state's public policy goals.

"The NYISO 2019 Power Trends report identifies that it is not actually in the public interest or public need to move forward with this project in particular," Richardson said. Quoting from the report, she said, 'Even with the Western New York and AC transmission projects already selected by the NYISO, congestion on the system will persist, complicating the state's ability to meet its renewable energy goals.'"

In its January 2019 award of renewable energy credit (REC) contracts, the New York Energy Research and Development Authority (NYSERDA) noted that it was supporting 20 large-scale renewable projects, including Heritage, and that 93% of the awarded capacity would be located upstate (in zones A-E), where clean energy resources are already abundant and access to load centers in southeastern New York is heavily constrained, bottled in so-called generation pockets.

In its 2022 Power Trends report issued last month, NYISO projected that "transmission constraints in these pockets will likely result in curtailment of 11% of the total potential renewable energy production across New York, with curtailment levels in some individual pockets as high as 63%. As more renewables are added to the bulk electric system without additional transmission expansion, greater congestion and curtailment levels will occur." ■

NYISO News

FERC Rejects Niagara Mohawk Tx Cost Allocation, ROE Adders

FERC on Friday rejected Niagara Mohawk Power's proposed cost allocation and recovery for the utility's share in the Smart Path Connect transmission project in upstate New York, including its request to increase its base return on equity (ROE) from 10.3% to 10.5% (*ER22-1201-001*).

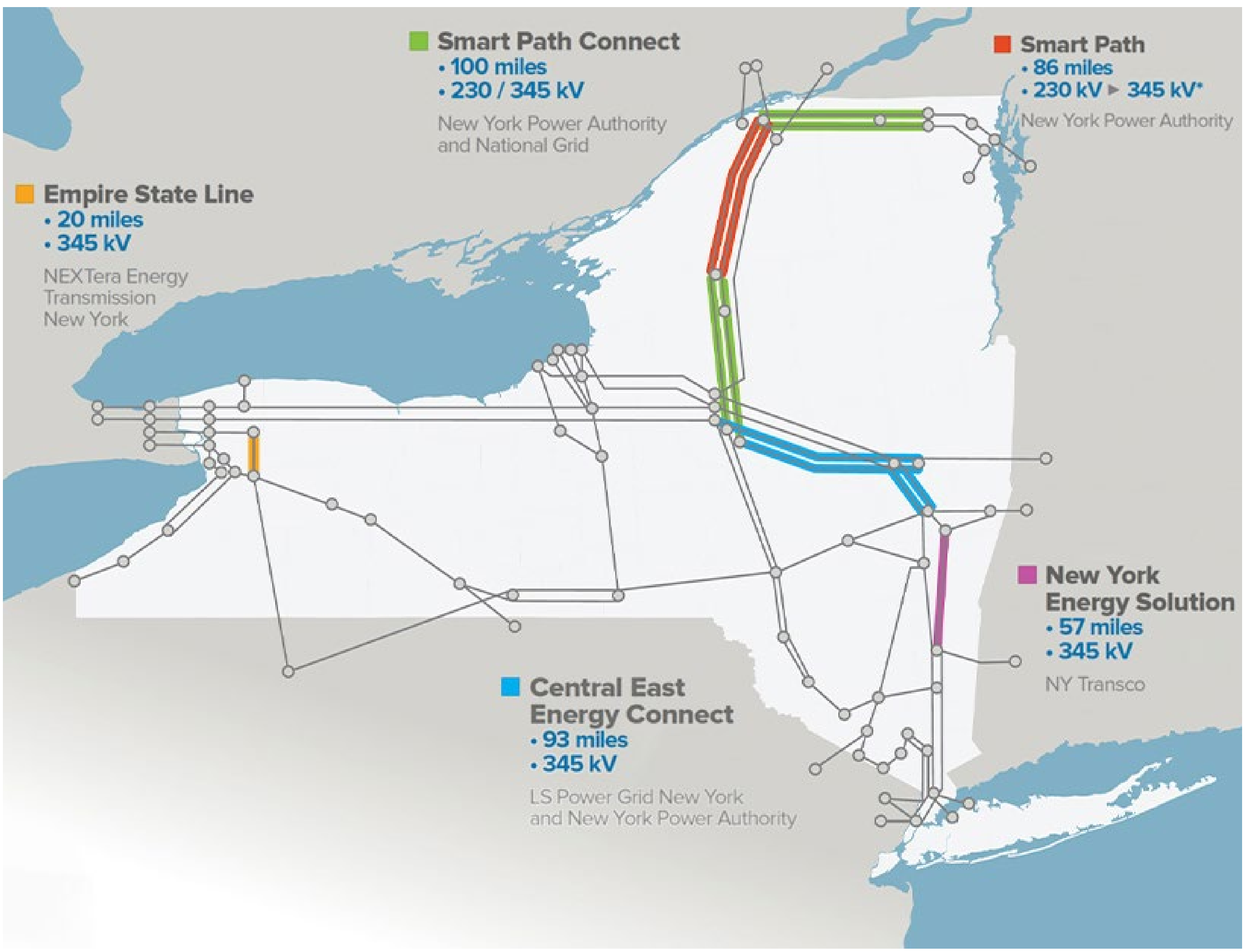
The commission also denied the utility's requests for a 50-basis-point adder to account for risks and incentives based on performance.

Niagara Mohawk is seeking to recover the $535 million in costs on the Smart Path Connect project, being built with the New York Power Authority (NYPA). The utilities estimate the total capital cost of the project at $1.2 billion, with an anticipated in-service date of December 2025. It would consist of rebuilding approximately 100 miles of 230-kV transmission lines to either 230 kV or 345 kV, along with associated substation construction and upgrades that, together with other projects currently under construction in New York, would establish a continuous 345-kV transmission path from northern New York to the downstate region to mitigate current and projected congestion.

FERC rejected the proposal as conflicting with a commission-approved 2015 transmission service charge (TSC) settlement with the New York Association of Public Power that set the utility's ROE at 10.3% (EL14-29).

"Niagara Mohawk voluntarily entered into the 2015 TSC ROE settlement, in which it agreed to a 10.3% ROE for all of its transmission facilities, inclusive of any incentive adders," FERC said. "Niagara Mohawk points to nothing in the [settlement] to suggest that the ROE established there applies only to either then-existing transmission facilities or transmission facilities that primarily have certain types of benefits. We find that, in the absence of any such language, the ROE established in the [settlement] should apply to all of Niagara Mohawk's transmission facilities, including its going-forward investments." ■

— Michael Kuser



The Smart Path Connect project consists of rebuilding approximately 100 miles of 230 kV transmission lines to either 230kV or 345kV.. | *NYPA*

NYISO News

NYISO Requests Extension, Clarification on Order 2222 Compliance

By Michael Kuser

New York City has established a goal of installing 100 MW of solar PV on city-owned buildings by the end of 2025. | *NYC.GOV*

NYISO on Monday filed a *request* with FERC for a 90-day extension of the Aug. 16 compliance deadline for Order 2222 and a separate *request* for clarification or rehearing regarding the order's requirements for operating reserves (ER21-2460).

In response to NYISO's original compliance filing, the commission June 17 directed the ISO to make more than 30 tariff revisions related to utility opt-in provisions and interconnection procedures, and to propose an effective date in the fourth quarter. (See *FERC Partially Accepts NYISO Order 2222 Compliance*.) Issued in September 2020, Order 2222 directed all commission-jurisdictional RTOs and ISOs to revise their tariffs to allow participation of distributed energy resource aggregations in their markets.

"Several of the required tariff modifications are extensive, require significant resources to develop and time to coordinate with the appropriate stakeholders," the ISO said. It said it must work with New York's distribution utilities to develop protocols that can be consistently applied by each utility, evaluate the burdens of the proposal against other options and work with stakeholders to resolve any outstanding concerns.

Extending the compliance filing deadline to Nov. 14 would result in rules that are fully compliant with Order 2222, the ISO said.

NYISO initially planned to implement its DER participation model, devised independently by the ISO in 2019, by the fourth quarter. But it "has faced several challenges in developing the databases, workflows and software automation necessary for DER implementation," it told FERC. "The complexity of the software, combined with staffing resource limitations, has led to significant delays to the 2019 DER project, which impacts the NYISO's ability to move forward with designing and developing the software necessary for compliance with Order No. 2222."

Heterogenous Aggregations

NYISO also requested clarification or, in the alternative, rehearing of a specific directive in FERC's June 17 order that addresses the provision of ancillary services by heterogenous DER aggregations — those consisting of different types of resources.

FERC had said that "so long as some of the DERs in the aggregation can satisfy the relevant requirements to provide certain ancillary services ... we find that those DERs should be able to provide those ancillary services through aggregation." It directed NYISO to file a proposed effective date "by which it will allow DERs in heterogeneous aggregations to provide all of the ancillary services that they are technically capable of providing through aggregation."

NYISO argued that the directive would require it to incorporate the operation of individual DERs into its real-time commitment and dispatch solution in a manner that is inconsistent with the accepted parts of its DER market design.

That could also compromise reliability, as it would require the ISO's "real-time commitment and real-time dispatch to solve a host of new constraints" and "could delay the timely posting of real-time dispatch instructions," it argued.

NYISO said its accepted DER market design does not require it to consider the operational status of each individual DER; instead, it is the aggregator's responsibility to dispatch its set of DER consistent with the composite offer it submits for the aggregation and the instructions the ISO issues to the aggregation. ■

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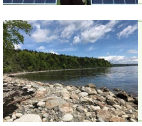

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PJM Challenged on Interconnection Rule Transition

Wide Support for Shift to Cluster Studies, 'First Ready' Procedures

By Rich Heidorn Jr.

Stakeholders last week welcomed proposed changes to PJM's interconnection procedures as long overdue but challenged the RTO's timeline and transition plans.

PJM last month proposed to switch from a "first-come, first-served" approach to a "first-ready, first-served" cycle, with individual serial studies replaced with cluster studies (*ER22-2110*). (See *PJM Files Interconnection Proposal with FERC*.)

More than 30 companies and groups filed comments by the July 14 deadline in response to the RTO's proposal, the result of 18 months of stakeholder talks.

The American Council on Renewable Energy said that while PJM's proposal "does not address the full range of needed interconnection reforms, the reforms proposed are an important first step and will likely mitigate several causes of queue backlogs."

The Organization of PJM States Inc. (OPSI) urged FERC to approval the proposal promptly but complained that PJM's proposed four-year transition and two-year default processing timelines are too long. It noted that 11 of the 14 jurisdictions in PJM have renewable portfolio standards, but they rely heavily on imports for compliance because of insufficient renewable generation within their borders.

"Despite the fact that interconnecting new generation is a critical component of open-access transmission service and should be one of PJM's core competencies, PJM's generator interconnection queue has been inefficiently processing interconnection requests," OPSI said. "PJM has been aware of state public policy goals for a number of years, but PJM continues to make little progress with the queue backlog. As a result, the current queue delays put some states in jeopardy of not meeting their near-term public policy goals as target dates inch ever closer."

It said PJM reported completing only 13 facilities studies in April and May, versus a backlog of 1,585. "This slow pace will not clear the backlog and illustrates the urgent need to immediately reform the broken interconnection process," the group said, adding that it will look to FERC's interconnection Notice of Proposed Rulemaking (*RM22-14*) for additional improvements. (See *FERC Proposes Interconnection Process Overhaul*.)

PJM transmission line near Conowingo Dam | *© RTO Insider LLC*

OPSI said PJM's proposals are similar to changes approved in other RTOs and proposed in FERC's rulemaking. "However, the length of the proposed process does not live up to the standards set by other RTOs," it said.

"OPSI is deeply concerned that, even under PJM's proposed reforms, a project entering the queue today may not be able to achieve commercial operation until nearly 2030. This is because PJM proposes to not process any new interconnection applications until as late as 2026, at which point projects would then have to undergo a two-year interconnection process. The prospect of such a lengthy timeline is troubling. It is important that PJM's proposed four-year pause on reviewing new applications be an absolute upper limit and that PJM invest the time and resources to substantially reduce this transition period."

$5 Million Threshold Challenged

Numerous stakeholders also criticized the RTO's transition plan to bar projects from remaining in the serial process "fast lane" — rather than starting over in a transition cluster study — if it contributes to the need for a network upgrade that exceeds $5 million.

"PJM has not demonstrated that this threshold has any correlation to whether a project in the queue is commercially ready," the PJM Power Providers Group said. "Instead, this arbitrary threshold will upend many projects that are fully permitted, have made significant investments based on the study results to date and are ready to move forward with construction and interconnection. … While a transition mechanism is needed to get to PJM's new proposed interconnection process, one that is based on actual demonstrations of commercial readiness would be far superior and less disruptive than what PJM has proposed."

Hecate Energy also challenged the $5 million cutoff saying FERC should "allow 'ready to go' projects (that are willing to post security and meet certain other milestones) to participate in the 'expedited process' during the transition, and to receive accelerated treatment after the transition, regardless of the cost of identified network upgrades."

Hecate also joined in a separate protest with six other developers, including Acciona Energy and Leeward Renewable Energy in challenging the threshold. "The PJM stakeholder process was selective, controlled by PJM, overlooked key proposals to address PJM's backlogged queue and cannot be relied upon as justification for PJM's queue reform filing," they said.

Competitive Power Ventures said "the proposal ignores late-stage projects … that have made substantial strides in development and can prove their readiness in objective and substantial ways, and that may have been delayed only as a result of PJM study delays. Such projects will be catapulted back in time, erasing all of the study work completed and proceeding under a completely new paradigm, while a project that may be later in the queue and may not be as far along in their development progress can leap frog over them simply because their projected network upgrade costs are $5 million or less."

But Pine Gate Renewables and Cypress Creek Renewables insisted in a joint filing that the $5 million threshold is "rooted in PJM's current tariff provisions, which establish $5 million as the minimum threshold for inter-queue cost allocation. Moreover, it is a carefully negotiated term that active PJM stakeholders debated extensively."

"PJM stakeholders and staff collectively and collaboratively developed and adopted the eligibility criteria and $5 million threshold to facilitate PJM's clearing of the existing backlog, while also allowing mature projects with little or no network upgrade responsibility to complete the interconnection process in a timely manner," they said.

The two companies asked FERC to approve the filing quickly, saying it was the result of "a robust, inclusive and consensus-driven stakeholder process."

'Awkward Position'

The Sierra Club, Natural Resources Defense Council and the Sustainable FERC Project said that PJM's filing restates existing tariff provisions that may be unjust and unreasonable under FERC's interconnection NOPR, including the lack of firm deadlines for its transition cycles and new rules.

"This puts FERC in the awkward position of being asked to rule that a Section 205 filing is just and reasonable at the same time it investigates if portions of that filing are unjust or unreasonable through a rulemaking," the groups said. "It is essential that FERC action in this docket does not prejudice the outcomes of the interconnection NOPR."

They also asked FERC to reduce PJM's proposed requirement that project developers provide proof of 100% site control to 90% and to add language "allowing flexibility when site control cannot be demonstrated because of regulatory requirements or obligations."

Uncertainty

The Solar Energy Industries Association called the proposal a "significant improvement" that "ensures efficient processing of interconnection requests that will allow lower-cost resources to come online faster."

But it said the proposed four-year delay in reviewing new applications will "create uncertainty for potential development in PJM once PJM begins reviewing new applications, as some developers will shift their efforts to other regions."

It said FERC should require PJM to submit biannual reports on its progress in reducing its queue backlog and a breakdown of the interconnection delays by transmission zone, to determine whether individual transmission owners are to blame.

For their part, PJM's TOs said in a joint filing that they "fully recognize that this reform is just an initial step that provides a flexible framework capable of accommodating future changes spurred by either PJM stakeholders or commission action." They noted that PJM stakeholders intend to consider additional improvements through the new Interconnection Planning Subcommittee reporting to the Planning Committee.

Also filing a protest was the developer of the proposed 2,100-MW SOO Green HVDC Link ProjectCo, which said the proposal is unfair to merchant transmission facilities, "which are unjustly included in the new services queue and will be forced into even longer interconnection delays."

Queue Groupings

National Grid Renewables Development, NextEra Energy Resources and RWE Renewables Americas said FERC should reject PJM's proposal to include projects in queue groupings AG2 (cutoff date March 31, 2021) and AH1 (Sept. 30, 2021) in the transition along with projects in group AG1 (Sept. 30, 2020).

PJM's initial transition proposal, presented to stakeholders in November 2021, included only group AG1.

"This decision respected projects that had some study work done and were thus entitled to rely on a continuation of the process they had embarked upon," the companies said. By contrast, "most, if not all, AG2 and AH1 projects entered the queue knowing or on notice that PJM had already began with its stakeholders an initiative to make sweeping changes to its queue rules."

PJM agreed to include AG2 and AH1 in the transition following lobbying by stakeholders holding positions in those groups, the three companies said.

The companies said including AG2 and AH1 would add 1,358 projects. Based on prior queues, only about 40 (3%) of those projects will be completed, they said.

'Adjacent' Parcels

Tenaska protested as arbitrary PJM's proposal to allow a project developer to make changes to the project site at its first two decision points as long as the new site and the initial site are "adjacent parcels." The company said PJM did not define "adjacent parcels" and provided no rationale for the requirement.

"A showing of 'adjacency' for a proposed site change is unnecessary for PJM in performing its function — assessing and studying a new project's impact on the network transmission system — if the proposed site change does not result in a material modification," it said.

Tenaska said solar project developers often file for a queue position after obtaining site control over a parcel of land but before conducting soil and geotech studies that could detect high levels of mercury or other elements that make the parcel undesirable. "Project developers then find nearby parcels of land, free from such environmental issues, and 'perfect' the site accordingly," Tenaska said. "While these parcels sometimes are adjoining, sometimes they are nearby but not directly adjoining."

The PJM study process examines the effect of new generation at a given point of interconnection to evaluate the effect of additional generation on reliability. "The real property status of the ground on which a project will be sited is wholly irrelevant to that analysis," Tenaska said.

The company said site control requirements are intended to prevent speculative proposals from entering the queue.

Thus, it said, PJM should allow developers to change their sites unless they cause "a material adverse effect on the cost or timing" of interconnection studies related to system upgrades, "consistent with" the policies in MISO and SPP. ■

PJM News

PJM Sees Wide Range of Costs in NJ OSW Tx Proposals

By Rich Heidorn Jr.

Delivering power from New Jersey's planned offshore wind projects will cost at least $1.2 billion and could total more than $7 billion, PJM officials said Monday.

The RTO released a 64-page *analysis* of the 26 point-of-injection (POI) scenarios it received in response to its transmission solicitation, which the New Jersey Board of Public Utilities (BPU) requested under FERC Order 1000's State Agreement Approach.

PJM conducted analyses on reliability, impact on LMPs, constructability and legal risks, officials told a special meeting of the Transmission Expansion Advisory Committee. PJM planners are seeking feedback on the analyses by the end of July to allow the BPU to select its preferred projects by October, said Sami Abdulsalam, a senior manager for transmission planning.

PJM received 45 proposals for Option 1a, for onshore upgrades to address reliability violations on existing facilities, with capital costs totaling about $100 million or less. Proposals for Option 3, for an offshore transmission network, came in with similar price tags.

More expensive were Option 1b (new onshore transmission connection facilities) and Option 2 (new offshore transmission connection facilities), each of which ranged between $500 million and $7 billion, PJM said.

"Offshore wind is expected to be a major driver of green job growth in New Jersey for decades to come and has demonstrated clean energy benefits," the BPU told *RTO Insider* in a statement. "The board, along with PJM, is pioneering the use of a highly competitive bidding process to select new transmission facilities to ensure that the power from the offshore wind turbines is delivered to New Jersey customers in an affordable and environmentally friendly way. The board will carefully review PJM's findings and take them into consideration as we continue the offshore wind transmission application review process. The board anticipates making a final decision on whether to select one or more transmission projects later in the year."

Cost Caps

Several of the POI scenarios offered additional capacity beyond the 6,400 MW desired, but they were not dispatched in the initial reliability analyses.

While 1A proposals had little to no cost-containment promises, eight of the proposers offered some sort of cost-capping mechanism on the other options, including an overall cost cap, a cap on return on equity and a cap on equity-debt mixes.

"Well capped proposals tend to have significantly lower cost overrun and other downside risks, such as high financing cost, compared to uncapped proposals," PJM said. "However, depending on the magnitude of project cost and base case revenue requirement, there may be a tradeoff between cost and risk levels."

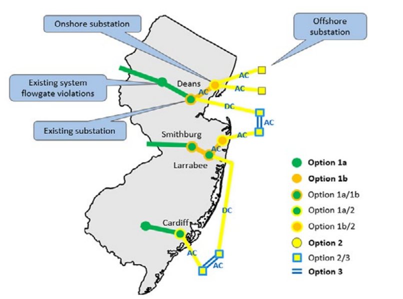
Option 1a proposals included conventional transmission solutions such as rebuilding or reconductoring existing transmission lines, as well as proposals for power flow-controlling devices. But PJM said it will "generally prioritize consideration of conventional solutions over power flow-controlling devices depending on the overall transmission capacity provided by and cost associated with the devices."

The 1a proposals would address only about half of the reliability violations identified. Incumbent transmission owner upgrades would address violations from injections that were not previously identified, Abdulsalam said.

Economic Analyses

PJM's Nick Dumitriu said the RTO and the BPU created offshore transmission scenarios involving various combinations of the Option 1b and 2 proposals and, after an initial reliability screening, selected a subset for economic analysis.

That analysis looked at estimated load LMPs and gross load payments for load-serving entities in New Jersey and also computed PJM-wide production costs and cost impacts on Pennsylvania zones.



Potential transmission options for New Jersey's offshore wind projects: Option 1a: Onshore upgrades on existing facilities; 1b: Onshore new transmission connection facilities; 2: Offshore new transmission connection facilities; 3: Offshore network | *PJM*

For Options 1b alone and 1b combined with Option 2, PJM said the difference between the proposals were "not significant," with the largest difference in New Jersey load payments less than 1% and differences in POI annual average LMPs 4.2% or less. Some scenarios resulted in curtailment of OSW, but that was limited to 0.4% of total annual generation.

PJM plans to expand the analysis of energy market impacts with capacity market simulations, Dumitriu said.

An analysis to determine incremental auction revenue rights (IARRs) identified "no available IARRs."

Construction Risks

PJM's Augustine Caven said the RTO's constructability evaluation found more risk in projects that impact the New Jersey Pinelands National Reserve or parcels in New Jersey's *Green Acres* program, which are managed for recreation and pother public purposes.

Proposals with underground cabling were found to have higher engineering risks but lower environmental impacts.

Projects that made landfall in the busy Raritan Bay were seen as having a higher risk of conflicts than proposals to connect at the Seagirt National Guard Training Center.

Among those who made proposals were three New Jersey utilities: Exelon's Atlantic City Electric, FirstEnergy's Jersey Central Power & Light and Public Service Enterprise Group's Public Service Electric and Gas. PSEG Renewable Transmission also teamed up with OSW developer Ørsted.

Con Edison Transmission and PPL Electric Utilities also made proposals, along with Anbaric Development Partners; Atlantic Power Transmission, a Blackstone Infrastructure Partners company; LS Power; Mid Atlantic Offshore Development, a joint venture of EDF Renewables North America and Shell New Energies US; NextEra Energy Transmission MidAtlantic Holdings; and Transource Energy.

Given the stakes involved, PJM's analyses are likely to be subjected to heavy scrutiny. The RTO's analysis surfaced one early disagreement: NextEra projected a cost of $4.68 million to reconductor the 230-kV Deans-Brunswick line, but PJM said PSEG estimated the cost at $73.3 million.

Additional reliability studies will be completed in July and August. ■

PJM News

PJM, AEP Address Ohio PUC on June Storms, Power Cuts

Surge in Demand Followed Storm Damage, Forcing AEP to Reduce Load

By John Funk

The powerful mid-June storms and demand surges in central Ohio forced American Electric Power to cut power to more than 150,000 customers to prevent further system damage, the company's top executives *told* Ohio regulators Wednesday.

More than 21,000 of the customers who lost power were in Columbus, prompting angry residents at the time to allege that the company balanced its system on the backs of the poor.

"I believe [circuit trips] are attributable to the storm plus the load that came on after," explained Toby Thomas, AEP senior vice president for energy delivery. "The reason I say that is the system load was [increasing the day after the storm]. We had fewer facilities left to serve the load, and the load was increasing significantly and very quickly."

The high winds affected 34 69-kV lines, 29 138-kV lines, one 345-kV line and 81 transmission-connected substations, according to the *information* the company submitted to the Public Utilities Commission of Ohio.

There are no significant generation sources in Columbus or nearby suburban communities, leaving the company few options as PJM grid managers informed AEP it would lose more of its system if it did not reduce load, Thomas said.

"The storms impacted a number of bulk electric systems throughout this state, as well as many other states," Mike Bryson, PJM's senior vice president of operations, told the commission. "Ohio was probably hit the worst of all the states.

"As the day [June 13] proceeded, we were in what PJM calls a hot weather alert, which is temperatures exceeding 90 degrees [Fahrenheit] in the area. AEP and Ohio were in that condition.

"Several transmission lines tripped in and around Columbus. When one of these lines goes down, other lines in the system have to carry that electricity, and if enough lines go down, the surrounding lines begin to reach or exceed their operating limit," Bryson explained.

The RTO's system analysis, which is constantly refigured as data on the condition of transmission lines come in, showed the remaining power lines were in jeopardy.

PJM issued a load-shed directive to AEP because of three heavily overloaded lines, Bryson said. "AEP had five minutes to implement this directive from PJM."

PUCO staff have been ordered to review the PJM analysis, as well as the scenarios that AEP Ohio said it faced, and issue a report.

The Ohio Consumers' Counsel has asked for an independent analysis by an independent auditor. ■

Ohio utility regulators on Wednesday questioned top PJM and AEP Ohio executives about the problems that led the utility to cut power to more than 120,000 Columbus customers during the elevated temperatures following a damaging derecho and two tornadoes in mid-June. | *Public Utilities Commission of Ohio*

PJM News

PJM Planning Committee Briefs

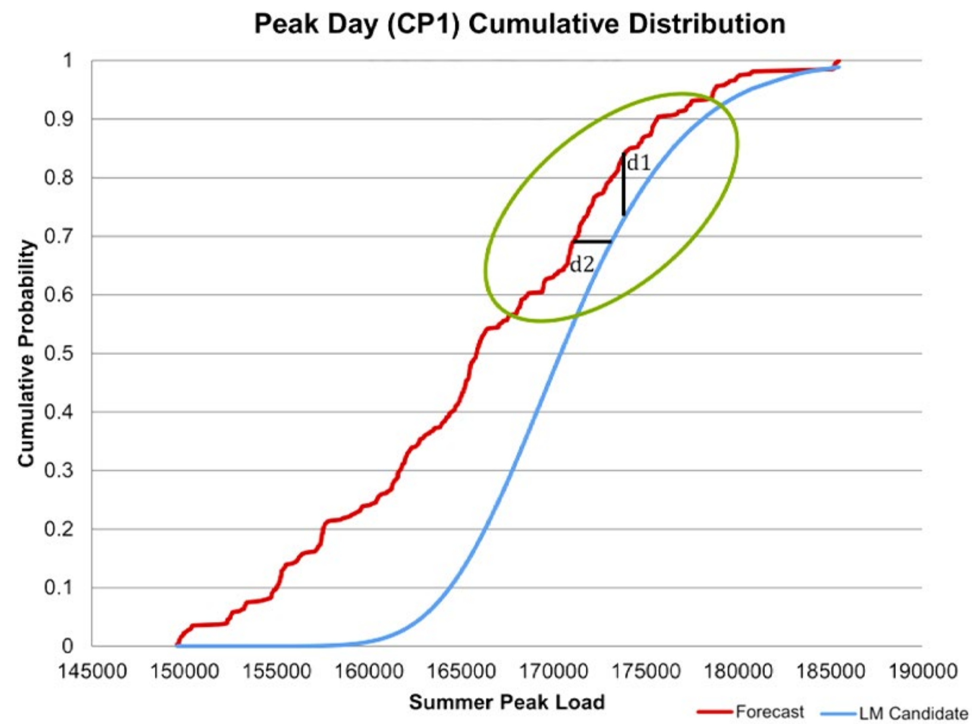
Consumers' Consultant Says PJM Load Model Based on 'Fiction'

VALLEY FORGE, Pa. — A consultant representing consumer advocates criticized PJM's proposed load model for the 2022 Reserve Requirement Study, telling the RTO's Planning Committee on July 12 that it would result in the over-procurement of about 1,000 MW.

Economist James Wilson — who represents advocates in New Jersey, Pennsylvania, Maryland, Delaware and D.C. — said that PJM is underestimating the assistance it could expect from its neighbors during peak loads because it models MISO, NYISO, the Tennessee Valley Authority and SERC Reliability's VACAR subregion as a single entity it terms the "World."

"The 'World' is a fiction," Wilson said. "No other RTO aggregates regions as diverse as New York and VACAR and MISO and TVA."

Wilson leveled his criticism after PJM's Patricio Rocha Garrido *presented* the RTO's proposal to use a load model from 2000-2010 for the capacity auction for delivery year 2026/27. The PC will be asked to endorse the selection at its August meeting.



PJM seeks to find load models that closely match the forecast based on cumulative probabilities (d1) and summer peak (d2). | *PJM*

Rocha Garrido said PJM considered 136 load models in its analysis, which he said is necessary because the coincident peak distributions from the RTO's load forecast cannot be used directly in PRISM, the loss-of-load-expectation software.

Under a method approved by the PC in 2016, PJM seeks to match its forecasted peak day distribution with the historical diversity from the World's peak.

In this year's analysis, PJM switched the World peak to the fourth week in July so that the RTO — projected to peak in the third week of the month — tops out in the same month but not the same week as the World. The switch was made to match the historical diversity between PJM and World peaks, Rocha Garrido said.

Wilson said PJM made "very arbitrary" load choices in deciding on a model that has a 99% match between PJM's and the World's "per-unitized" peaks. "In previous years it's always been 97% or 95%," he said, noting that TVA peaked in the same day as PJM in only four out of the 23 last years, while NY, MISO and VACAR peaked in the same day as PJM in only seven or eight.

The four neighbors averaged more than 7,000 MW below their peaks at the time of the PJM peak — 3.9% of the PJM peak — over the 23 years, Wilson said. He said the choice would result in about a 1,000-MW increase in the reliability requirement. By combining the four neighboring regions, PJM is "pretending they would help each other rather than PJM," Wilson said.

Michael Cocco, of Old Dominion Electric Cooperative (ODEC), asked PJM to provide a comparison of the individual regions' peaks against its peaks.

Rocha Garrido said the RTO had conducted analyses that looked at the neighboring reasons separately and got "similar results."

"The data supports 99% rather than 97%," he said.

PJM's Tom Falin, chair of the Resource Adequacy Analysis Subcommittee (RAAS), also defended the choice, saying the diversity between PJM and the World was less than 3% in 20 of the last 23 years.

"This is largely a judgment call in the end," he acknowledged, saying there was no formula for determining the capacity benefit of PJM's ties with its neighbors.

Falin also said not all of PJM's assumptions were conservative, noting that PRISM assumes no transmission constraints within any of the regions. He also questioned whether other regions would call on demand response — which figures into their capacity calculations — to help PJM.

Wilson said he will make a presentation on his proposed changes to the load model at the next meeting of the RAAS on Aug. 3.

'Time to Get Involved' in CIRs for ELCC Resources

PJM's Brian Chmielewski provided an *update* on the PC's special session on capacity interconnection rights (CIRs) for effective load-carrying capability (ELCC) resources such as renewables, which cannot run at their maximum output for more than 24 hours.

CIRs set an upper bound on the amount of installed capacity attributed to a generation capacity resource.

At the June 24 meeting, stakeholders discussed competing proposals from PJM, LS Power, Global Infrastructure Partners' *Eolian* and economist Paul Sotkiewicz of E-Cubed Policy Associates.

PJM News

The group originally planned a final review of the proposals for this Wednesday, followed by a nonbinding poll. But the meeting was postponed until late August to allow for more offline discussions to forge compromises, Chmielewski said.

PJM's Brian Chmielewski provided an update on the PC's special session on CIRs for Effective Load Carrying Capability (ELCC) resources. | © *RTO Insider LLC*

A first read is expected no sooner than the September PC meeting, with the new rules implemented for the 2025/26 Base Residual Auction.

"Now is the time to get involved before we get into polling," Chmielewski said.

Informational Update on NOPRs

Members received updates on FERC's Notices of Proposed Rulemaking on generator interconnection procedures (RM22-14), transmission system planning performance requirements for *extreme weather* (RM22-10) and a requirement that transmission providers submit one-time *informational reports* on extreme weather vulnerability assessments, climate change and electric system reliability (RM22-16).

PJM has planned two workshops on the extreme weather planning NOPR: one on July 21 to provide an update on its preliminary plans for its response and to solicit input from stakeholders, and one Aug. 12 to discuss the final draft response.

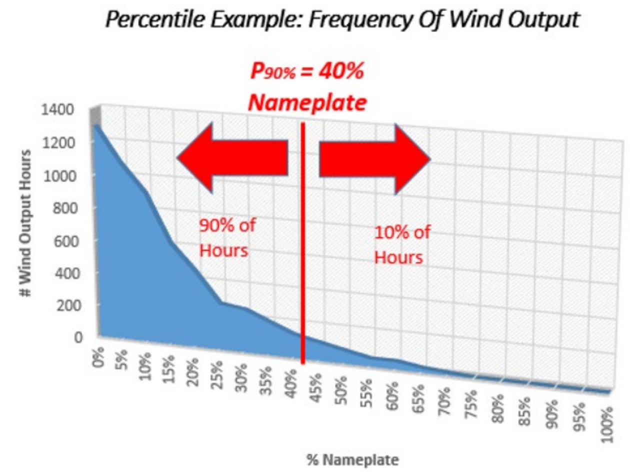
The RTO has previously recommended that FERC address resilience concerns by requiring a new transmission driver covering gas-electric vulnerabilities, reducing the number of critical grid facilities and strengthening infrastructure through storm hardening, winterizing generation resources and infrastructure redundancy.

ODEC's Cocco said he hoped PJM would offer comments supporting its role as a "thought leader on gas-electric coordination."

Generator Deliverability Education

PJM transmission planning engineer Jonathan Kern gave an *update* on the RTO's proposed changes to generation deliverability testing.

Kern said the testing procedures "have been relatively unchanged for many years" despite the increased variability in dispatches because of the spread of renewables.



Percentiles represent the share of hours with output below a particular level. This example shows that onshore wind is generating 40% or less of nameplate capacity in 90% of the hours. | *PJM*

Among the changes is the grouping of resource types into three "block dispatches" based on their economics, with block 1 containing the units with the lowest offer prices (nuclear, wind, solar, hydro, pumped storage and other renewables); the more expensive block 2 (coal and combined cycle gas); and the most expensive, block 3 (IC/CT/ST oil and gas). "It better describes how PJM operates," Kern said.

PJM also plans to redefine the "light load" period to include 10 a.m.-3 p.m. where the coincident peak load is between 40 and 60% of the annual peak for historical generation data necessary to represent the 50% load level.

"Solar is putting out large amounts of energy during the daytime. That's completely unaccounted for" in PJM's current modeling, Kern said.

PJM is also introducing the concept of "helpers" (generation with a negative DFAX, for which a decrease in the generation output increases the loading on a flowgate under study) and "harmers" (those with a positive DFAX, meaning a boost in generation would increase loading on the flowgate).

The new rules also will include more wind and solar in base case dispatches, with fixed solar rising from 38% to 47 to 55% of nameplate capacity in summer. Onshore wind would increase from 13% to 16 to 20%, and offshore wind would jump from 30% to 33 to 38%.

The RTO also plans to consider the impact of wind sited in MISO in both its light-load and winter tests. "Essentially, we're looking at: What are the loopflows that would result from those wind units being dispatched at higher levels in MISO?" Kern explained. ■

		Base Case Dispatch	
Period	**Resource Type**	**Existing**	**Proposed***
Summer	Fixed Solar	38%	47-55%
Summer	Tracking Solar	~60%	64-66%
Summer	Onshore Wind	13%	16-20%
Summer	Offshore Wind	~30%	33-38%
Winter	Fixed Solar	5%	5%
Winter	Tracking Solar	5%	5%
Winter	Onshore Wind	33%	40-43%
Winter	Offshore Wind	60%	55-57%
Light Load	Fixed Solar	0%	52-59%
Light Load	Tracking Solar	0%	54-58%
Light Load	Onshore Wind	40%	29-34%
Light Load	Offshore Wind	60%	46-49%

* Proposed values are based on seasonal capacity factors that vary based on which region resource is located in

Red Font = CIR MW

Summary of base case dispatch changes for wind and solar under PJM's proposed changes to its generator deliverability test. | *PJM*

— Rich Heidorn Jr.

PJM Operating Committee Briefs

Issue Charge OK'd on Internal NITS Process

VALLEY FORGE, Pa. — The PJM Operating Committee last week approved an *issue charge* on an initiative to ease the process for scheduling internal network integration transmission service (NITS).

The RTO said its current tariff makes little distinction between internal and external service requests, requiring all requests be studied to ensure sufficient headroom or the need for system upgrades. (Internal requests are for internal generation serving internal load; external/cross-border requests refer to external generation serving internal load or internal generation serving external load, respectively.)

The rules require internal NITS customers to notify PJM a year in advance of the expiration of their service that they want a rollover, as required for cross-border service, which the RTO termed a "valueless procedure."

The initiative seeks to revise the tariff and manual language to differentiate between the two types of requests and reduce administrative burdens on entities using internal service.

Susan McGill, PJM | © RTO Insider LLC

PJM's Susan McGill said no changes had been made since the issue's first read in June. (See "Internal NITS Process," *PJM Operating Committee Briefs: June 9, 2022*.) She said the issue could have been dealt with as a "quick fix" but that the RTO wanted to solicit members' feedback.

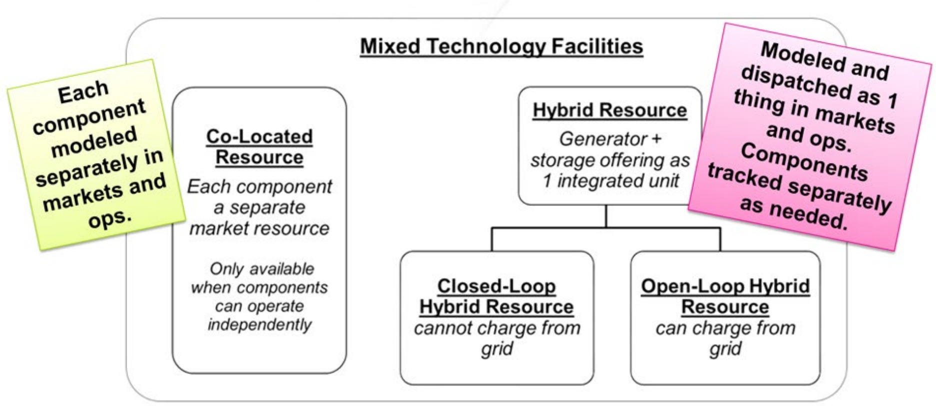
The issue charge was approved by acclimation.

'Quick Fix' Changes OK'd for Manual 14D

Members also endorsed "quick fix" changes to Manual 14D: Generator Operational Requirements regarding the deactivation analysis timeline.

Current rules require notification of PJM at least 90 days in advance of the planned deactivation. Under the changes, desired deactivation dates would be no earlier than:

- July 1 of the current calendar year for notices received between Jan. 1 and March 31;
- Oct. 1 of the current calendar year for notices received between April 1 and June 30;



Terminology and categories in Manual 14D | *PJM*

- Jan. 1 of the following calendar year for notices received between July 1 and Sept. 30; and
- April 1 of the following calendar year for notices received between Oct. 1 and Dec. 31.

PJM will study deactivations four times per year for all notices received prior to the study commencement dates (Jan. 1, April 1, July 1 and Oct. 1).

PJM's Dave Egan explained actions that PJM will take to address stakeholders' concerns over the transparency of reliability-must-run (RMR) contracts, which are used to keep a generating unit operating beyond its requested deactivation date to maintain reliability until necessary transmission upgrades can be completed.

In response, a generation owner can either file its proposed cost-of-service recovery rate (CSRR) with FERC or receive the deactivation avoidable cost credit (DACC) specified in the tariff.

Egan said PJM will announce it had requested a plant to extend its operations at the second read of the deactivation notice before the Transmission Expansion Advisory Committee. The RTO will announce at subsequent TEAC meetings when the generation owner submits a CSRR to FERC and after the commission accepts the CSRR filing or the generation owner agrees to the DACC.

Michelle Bloodworth, CEO of coal industry group America's Power, said RMRs would be little more than "a Band-Aid fix if there's a flood of retirements."

Egan acknowledged that RMRs are used only to ensure transmission security and not resource adequacy.

"We're not looking at the long-term future," he said. "It's done on a case-by-case basis."

First Read for Hybrid Rules

PJM's Andrew Levitt presented a first read on manual language conforming to FERC's July 12 order accepting the RTO clarifying its rules for hybrid resources and mixed technology facilities (*ER22-1420-002*). PJM filed its *proposal* on March 22.

Changes will be made to Manual 10: Pre-Scheduling Operations for eDART reporting requirements and Manual 14D: Generator Operational Requirements for changes regarding metering requirements, outage reporting and voltage schedules, with a new section 13 for mixed technology facilities.

The OC will be asked to endorse the changes at its next meeting.

PPL Delays DLR Implementation to September

PJM's Dave Hislop told the committee that PPL has delayed the implementation of dynamic line ratings on three circuits until mid-September because further work is needed to finalize changes to its energy management system with its vendor.

The changes to the double-circuit 230-kV Susquehanna-Harwood and the 230-kV Juniata-Cumberland lines are scheduled to take effect on Sept. 13 for the day-ahead market and Sept. 14 for real time. ■

— Rich Heidorn Jr.

PJM Adopting New Web Protocols in Response to Cybersecurity Concerns

Russia, Allies Linked to DDOS Attacks

By Rich Heidorn Jr.

VALLEY FORGE, Pa. — PJM will stop supporting older, less secure versions of transport layer security (TLS) encryption in its remaining applications between now and Aug. 17 because of cybersecurity concerns.

TLS protects data on websites and securely transfers data between clients and servers.

PJM Chief Information Security Officer Steve McElwee *told* the Market Implementation Committee on Wednesday that passwords and market data can be intercepted and decrypted in TLS 1.0 and 1.1.

The RTO disabled 1.0 and 1.1 in its training environment last year and has replaced them on several production PJM Tools applications and on PJM.com. It is expediting the transition for the remaining applications in response to a recommendation from the U.S. Department of Homeland Security. Users will not be able to access the applications unless browser and browser-less API interactions use TLS 1.2.

"We're really working aggressively to reduce the attack surface for adversaries," McElwee said. "We had longer-term plans to let you adapt, but we had to accelerate that. We recognize that could cause some impact for you."

McElwee said about 98% of PJM stakeholders have already adopted the new TLS. "It's that 2% that we really want to track down," he said.

Russian Threats

McElwee repeated his briefing about the changes before the Operating Committee on Thursday, saying that "if you get a communication from us, it's not a phishing attempt. It is legitimate."

He also told the OC of other cybersecurity issues, including a June 22 Microsoft intelligence *report* that said the software maker had detected Russian network intrusion efforts on 128 organizations in 42 countries outside of Ukraine.

Pro-Russia groups have been linked to many distributed denial of service (DDoS) attacks, he said, including a cyber collective called Killnet that *claimed responsibility* last month for DDoS attacks in Lithuania in response to the closure of transit routes within the Russian exclave of Kaliningrad.

PJM is following DHS' "shields up" recommendations, including blocking international and anonymized network traffic and exercising incident-response plans.

"We recognize the threat of retaliation against the U.S. is very real, so we're [doing what we can] to stay on guard against that threat," McElwee said.

He recommended reading the Cybersecurity and Infrastructure Security Agency's May alert on threats to *managed service providers* and their customers, and its June *warning* on exploits targeting VMware Horizon and Unified Access Gateway servers.

He also urged PJM member companies to use measures such as multifactor authentication to protect their email systems. "Business email compromise can have a lot of impact on your organization," he said. "A cyberattack against one of us could affect all of us."

GMD Vulnerability Analysis Update

PJM's Stanley Sliwa *told* the Planning Committee on July 12 that the RTO hopes to complete its assessment of its vulnerability to geomagnetic disturbances (GMDs) by the end of the year.

NERC reliability standard *TPL-007-4* requirement R3 requires the RTO to establish acceptable steady-state voltage performance for its system during a GMD event, and prevent a voltage collapse and cascading and uncontrolled islanding.

But it allows loss of generation, transmission configuration changes and re-dispatch of generation if time permits. Also permitted are interruptions of firm transmission and manual or automatic load shedding.

Voltage performance is examined in three stages, beginning with the posturing of the system in response to space weather information warning of a potential GMD. "If we know PJM is expecting a GMD, certain actions can be taken to prepare the system," Sliwa explained.

Performance also is measured after the onset of the event, but prior to loss of elements. The final measurement is made after the potential loss of reactive power compensation devices and other transmission facilities as a result of protection system operations or misoperations during an event. ■

Product	Implementation Date
FTR Center	July 19
DR Hub	July 25
Markets Gateway, Capacity Exchange	July 27
Data Viewer, eDART	Aug 01
Power Meter, InSchedule	Aug 10
MSRS, SSO, PJMeSuite	Aug 17

PJM will stop supporting older, less secure versions of its transport layer security (TLS) in its remaining applications because of cybersecurity concerns. The RTO will begin requiring use of TLS 1.2 on applications between July 19 and Aug. 17. | *PJM*

PJM News

PJM MIC Briefs

Rule on Variable Environmental Costs and Credits Advances

VALLEY FORGE , Pa. — The PJM Market Implementation Committee last week approved a joint RTO-Independent Market Monitor *proposal* to update rules governing variable environmental charges and credits and their inclusion in cost-based energy offers.

Under the proposal, generation units receiving the production tax credit (PTC) or renewable energy credits (RECs) would have to reflect them in their fuel-cost policies (FCP) when submitting non-zero cost-based offers in the energy market.

Melissa Pilong, PJM | © RTO Insider LLC

The package includes changes to *Manual 15* and *Schedule 2* of the Operating Agreement. Under the changes, the review of emissions rates would be reduced from annual to every three years to align with the FCP review process. Emissions rates should not change drastically year to year, said PJM's Melissa Pilong. The market seller is responsible for updating rates to ensure their accuracy.

The new rules would also add transparency on the information required from market sellers.

The IMM's Joel Luna *told* the committee that RECs and PTCs must be included in cost-based offers under the same standards as fuel costs, and must be "accurate, verifiable and systematic."

"In plain terms, it cannot be made up," Luna said.

RECs can be based on the actual transaction price (inventory cost or contract-based) or spot price (replacement cost). If the actual price is used, the FCP must say how often the price will be updated and the period for the price (e.g., last year). If a spot price is chosen, the FCP must identify the source (e.g., broker/publication), data point used (e.g., midpoint/settled) and update frequency (e.g., weekly).

Units with bundled power purchase agreements making non-zero cost offers can use the actual REC price or spot REC price.

PTC rates are defined by the Internal Revenue Service and grossed up based on the effective corporate tax rate. For a company with a 21% tax rate, the $27/MWh PTC converts to $34.18/MWh ($27/(1-0.21)).

Jeff Whitehead of GT Power Group questioned why the RTO is including out-of-market revenue, saying it's at odds with the effective elimination of the minimum offer price rule.

"We have a couple of 'no' votes [because of] the policy implications," he said. "We're wondering if we're going the wrong direction with this policy."

"Having the net cost reflects the true marginal cost of the units," said Luna. Without such considerations, "you'll be sending [solar and wind generators] a signal to curtail, and they will not respond."

The proposal passed 180-39 (82%) with five abstentions. Stakeholders said they preferred the new rule over the status quo by 178-32, with 21 abstentions. It will receive a first read at this week's Markets and Reliability Committee meeting.

Market Suspension Rules OK'd

Members also approved a revised PJM/IMM package of *changes* to the treatment of long-term market suspensions.

The changes are intended to address a gap in tariff language regarding how to settle the real-time market if prices can't be determined. They would set separate rules for suspensions of less than and more than 24 hours.

Under a compromise, the intermediate suspension category was eliminated, and the "short term" suspension was expanded to 24 hours from six.

The changes apply to the real-time market when dispatch is unable to provide zonal economic dispatch results for at least seven five-minute intervals within a market hour. For suspensions up to 24 hours, PJM would substitute the missing prices with the average real-time price of those from the preceding and subsequent hours.

Suspensions longer than 24 hours would use day-ahead prices, if available. If not available, energy LMPs would be priced hourly based on an aggregate supply curve from available offers (including available resources not running), with actual generation megawatts serving as the proxy for demand. Loss LMPs and congestion LMPs would be set to $0.

The change included a *friendly amendment* by Shell Energy's Sean Chang that stated if the suspension is greater than six hours but less than 24 hours, PJM would use day-ahead prices for corresponding hours.

The changes do not affect suspensions of the day-ahead market, which will continue to use real-time prices as defined in tariff section 1.10.8(d).

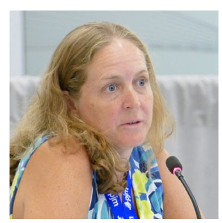
Tom Hyzinsky of GT Power Group expressed concern with the changes, saying "day-ahead and real-time can be two completely different markets."

Tim Horger, PJM | © RTO Insider LLC

PJM's Tim Horger said 90 to 95% of load clears in the day-ahead market. "That's why I feel confident using it for six to 24 hours."

The changes were approved by acclimation with no objections or abstentions.

Initiative Approved on Weather-sensitive Load Compliance Rules



Sharon Midgley, Exelon | © RTO Insider LLC

Members approved an *issue charge* proposed by Sharon Midgley, of Exelon and subsidiary Baltimore Gas and Electric (BGE), to explore an alternative demand response/price-responsive demand (PRD) compliance construct for weather-sensitive load, such as residential demand impacted by summer air conditioning.

Midgley said the current rules compare metered load under prevailing weather conditions to the peak load contribution (PLC) based on weather-normalized peak weather conditions. Capacity compliance for DR and PRD is currently based on the firm service level (FSL), calculated as the PLC minus the amount of installed capacity that the DR/PRD resource cleared in the capacity auction. Compliance is achieved if metered load is at or below the FSL.

Over the summers of 2018-2021, the actual peak load for BGE's weather-sensitive residential customers averaged 13% higher than the weather-normalized peak load. The disparity was the largest in 2019, with weather-normalized load 22% lower than actual load.

The discrepancy means DR and PRD providers may not be able to offer the full capability of their programs into the capacity market because of unachievable FSL, Midgley said.

Midgley revised the issue charge to make out-of-scope changes to the current compliance construct's ruleset, which caps monetization to the customer's PLC.

Monitor Joe Bowring opposed addressing the issue separately from ongoing discussions at the Resource Adequacy Senior Task Force. "We don't think this is a narrow issue, and we don't think it should be carved out from the RASTF," he said.

Midgley said the RASTF's work plan didn't envision "getting to that level of detail."

"I don't see this as asking for special treatment," she added.

The issue charge was approved with one objection for 22 members.

First Read on Day-ahead Zonal Load Bus Distribution Factors

PJM's Amanda Martin gave a first read of a *problem statement* and *issue charge* addressing day-ahead zonal load bus distribution factors.

The RTO's current rules state that the default distribution of load buses for a zone in the day-ahead energy market is the state estimator distribution of load for that zone at 8 a.m. one week prior to the operating day. That means the share of the zonal load attributed to each node remains constant for all 24 hours, even though the node's share of total load may vary throughout the day because of nonconforming loads, such as behind-the-meter solar and data centers. This can cause a mismatch between the day-ahead nodal loads and real-time state-estimated load.

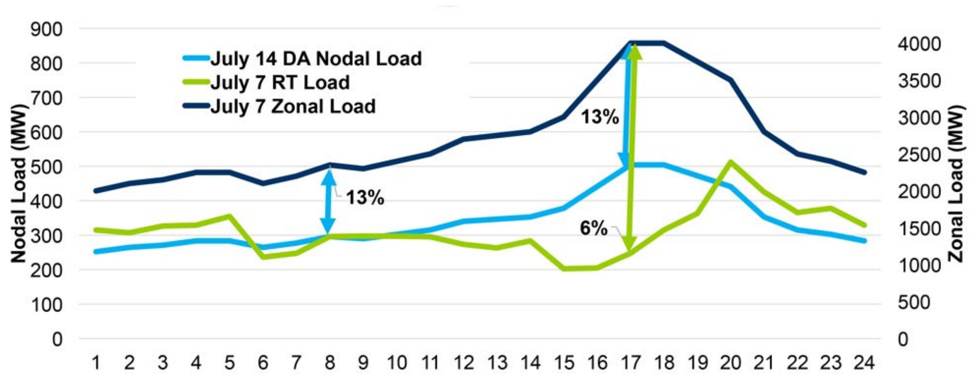
"This seems overly simplistic given the data we have," said consultant Roy Shanker. "I'm surprised we're doing it this way."

The committee will be asked to approve the issue charge at its next meeting under the "CBIR Lite" (Consensus Based Issue Resolution) process. The work is expected to take four months, with changes to tariff section 31.7c(i) and updates to Manual 11 and Manual 28.

IMM Balks at New Capacity Options for Generation with Co-located Load

Bowring expressed concern over proposals to change how PJM treats capacity offers from generation with co-located load.

According to the *problem statement* proposed by Brookfield Renewable Trading and Marketing



This example shows the July 14 DA nodal load (left scale) is consistently 13% of the zonal load (right scale), while the July 7 RT load is only 6% of the zonal load. | *PJM*

and Constellation Energy — and approved by stakeholders in January — PJM's current rules do not allow capacity offers for the full output of generating units that are contracted to physically serve co-located loads, instead requiring owners to retire a portion of their capacity to serve such loads.

The companies said large commercial customers with fast-response curtailment capability (less than 10 minutes) are seeking physical supply options for loads that are directly interconnected behind carbon-free generation resources such as hydro and nuclear.

Changing the rules would provide customers more options and give PJM the ability to call on the generators serving such interruptible customers, backers say. The initiative could result in modifications to capacity market rules, cost-based offer rules and relevant manual provisions to account for co-located load configurations.

"We have lots of large loads that can drop at any time on the system," said Shanker. "Operationally, I don't think this is anything new." He added, however, that the magnitude could be increasing.

But Bowring said the proposal is a "significant change" that removes, rather than adds, flexibility. He said it could mean that a large nuclear power plant will no longer provide its energy to PJM in most hours but will be paid as if it is a capacity resource.

Discussing the impact of an unexpected drop in the behind-the-generator load, he said, "It's not just a load drop. It's a sudden increase in generation. ... Everyone needs more details about this to be convinced it's business as usual."

He also said the impact of the proposed change on the provision of reactive power and frequency control by the generator must be explicitly defined.

Jason Barker, Constellation Energy | *© RTO Insider LLC*

Constellation Energy's Jason Barker asked Bowring to be specific about the analysis he seeks, saying he wanted to avoid his request from "unduly delay[ing] consideration of this process."

"The process has worked in the past to adjust interconnection service agreements," Barker said.

PJM's Jeff Bastian said the RTO currently operates the system prepared for the loss of its largest units. "If you lose a 300-MW load behind the meter of a generator, the system is going to react the same as if you lose a 300-MW paper mill or any other kind of load that's connected to the system. So I'm not sure I understand the concern," he said.

PJM's Lisa Morelli said she will continue discussions outside of the MIC "to make sure we're not talking past each other."

CT Make-whole Loophole Discussed

Members discussed a proposal to close a loophole that allows combustion turbines to ignore PJM dispatch without financial consequences.

Under PJM rules, most resources are made whole to the lesser of their actual megawatt output or the RTO's desired output. But CTs are always made whole to their actual megawatts, regardless of how well they follow dispatch, Morelli explained.

PJM and the Monitor said the special treatment made sense before the implementation of Capacity Performance, when CTs were not required to have a dispatchable range. Most CTs now share similar dispatchability to the

PJM News

rest of the fleet, they said.

Flexible CTs received 72% of all balancing operating reserve credits in 2021, "so changes to this rule can be quite meaningful," said Morelli.

PJM reran the highest uplift days for CTs from summer 2021 and found that with the CT exception eliminated, uplift payments to CTs would drop from $13.4 million to $12.2 million over the eight days — a reduction of $1.3 million (10%).

"$1.3 million for eight days is pretty significant, so that would grow over a whole year," Morelli said. "I think it does make a strong case for removing the CT rule."

She called the change "low-hanging fruit," although she acknowledged, "we realize some CTs are not flexible."

Timing of ARR/FTR Market Task Force Talks at Issue

PJM backed off from a recommendation to delay additional work on new seasonal auction revenue rights (ARRs) and financial transmission rights (FTR) products in the face of opposition by DC Energy.

In a poll of 129 members of the ARR/FTR Market Task Force, 98% answered "yes" to the question: "Should the annual ARR/FTR products be retained and seasonal products be added (recognizing that fewer rounds would be required)?"

Almost two-thirds (64%) of those polled also supported "pursuing any other ARR/FTR market reforms at this time."

A much smaller majority (57%) supported retention of the annual ARR/FTR products. "So no real conclusory evidence there on where people want us to go," said task force facilitator Dave Anders.

Dave Anders, PJM | *© RTO Insider LLC*

Asked what process changes the task force should pursue to simplify auctions to allow additional products, 60% favored adjusting the structure of the annual auction (e.g., number of rounds), and 83% supported modifications to overlapping periods and/or class types.

In contrast, "adjustments to the annual ARR allocation process" drew only 26% support.

After reviewing the poll results, Anders recommended that the task force delay discussions on new products until late 2023 or early 2024 to allow the September 2022 Phase I (new FTR product type) and February 2023 Phase II (ARR changes) be implemented first. Those changes were approved by FERC on March 11 (*ER22-797*).

"Let's make sure we've got some stability before we make additional changes," he said.

Anders also proposed revising the task force's issue charge to "narrow the focus down to, what do we want to accomplish going forward?"

"The issue charge was exceptionally wide open," said Anders. "Being able to say the task force is done is an important thing."

"Where did this recommendation come from?" asked Bruce Bleiweis of DC Energy. "It wasn't discussed."

"As facilitator of the task force, this is my recommendation," responded Anders.

Bleiweis said he agreed with revising the charter, but he said he would oppose waiting "another year and a half to begin those discussions."

"I don't think we need to wait for the implementation of the new products and class types, because they're different from what we're recommending" he said.

"This is just my recommendation," Anders responded. "We'll go whatever direction the stakeholders want to go."

Anders said he would return to the group with "a more definitive path forward."

Separately, the MIC endorsed changes to Manual 6: Financial Transmission Rights as part of the periodic review and to make changes conforming with FERC's March order. The changes include definitions of new FTR class types and clarification of the remaining time frame for existing off-peak classes. Also added was a new rule on the minimum price for clearing options. The first of the changes will be effective Sept. 1 and be applied first to the October 2022 auction, which opens in mid-September.

Wolf's Appeal Reinstates RGGI Costs in Pa. — for Now

On July 11, Pennsylvania Gov. Tom Wolf's administration appealed the Commonwealth Court's injunction blocking the state from entering the Regional Greenhouse Gas Initiative (RGGI), effectively lifting the injunction. (See *Court Blocks Pa. from Joining RGGI*.)

"As a result, generators can include RGGI costs in their cost-based offers per their approved fuel-cost policies beginning on July 13 for July 14, unless and until the injunction is reinstated, if it is," the Monitor advised in a *notice*.

Manual Revisions Approved

Members also endorsed revisions to:

- Manual 18: PJM Capacity Market to conform with FERC's July 12 order regarding hybrid resources (*ER22-1420*). A hybrid is defined as a single generator plus a single storage facility operating as a composite. The change adds hybrid resources to the exemption from the capacity market must-offer rule currently applied to intermittent resources and capacity storage resources.
- Manual 28: Operating Agreement Accounting to support the start-up cost offer development proposal the MRC approved in May. It clarifies what intervals are included in segments for determination of balancing operating reserve credits. ■

— Rich Heidorn Jr.

The distance between the orange (dispatch) line and blue (actual operation) line represents excess MWs for which the combustion turbine can receive make-whole payments under current PJM rules. | *PJM*

PJM Considers Changes to Max Emergency Status for Coal Plants

By Rich Heidorn Jr.

VALLEY FORGE, Pa. — PJM's Operating Committee last week conducted a second first read on RTO and Independent Market Monitor proposals to address the management of remaining run hours for coal and other generating resources limited by fuel shortages or environmental restrictions.

The proposals would change PJM operating procedures for generators in "maximum emergency" status, used to conserve remaining run hours.

Manual 13 currently limits generators on maximum emergency status to a 32-hour remaining run time for steam units, and 16 hours for combustion turbines.

Denise Foster Cronin, representing the East Kentucky Power Cooperative, which owns the coal-fired H.L. Spurlock Station near Maysville and John Sherman Cooper Station near Somerset, said 32 hours is not sufficient. "PJM needs more flexibility than current rules provide," she said during the meeting Thursday.

The session featured a briefing on the current coal supply shortage on behalf of EKPC and America's Power. Seth Schwartz of *Energy Ventures Analysis* showed *slides* illustrating a 200 million ton drop in coal burn in the U.S. from 2018 to 2020, a reduction of one-third, before rebounding by 65.6 million tons in 2021.

In PJM, coal plant capacity factors dropped from 70% to 33% between 2007 and 2020 before jumping to more than 45% in the first quarter of 2022.

Many coal plants are dispatched after gas combined cycle plants and are run for reliability, Schwartz said.

The uncertainty makes it difficult for coal plants to maintain adequate fuel inventories. Coal suppliers need longer-term contracts to support investments to increase production, Schwartz said, and railroads often require annual contracts with take-or-pay penalties.

PJM's Chris Pilong said resources in maximum emergency status are not excused from performance assessment intervals.

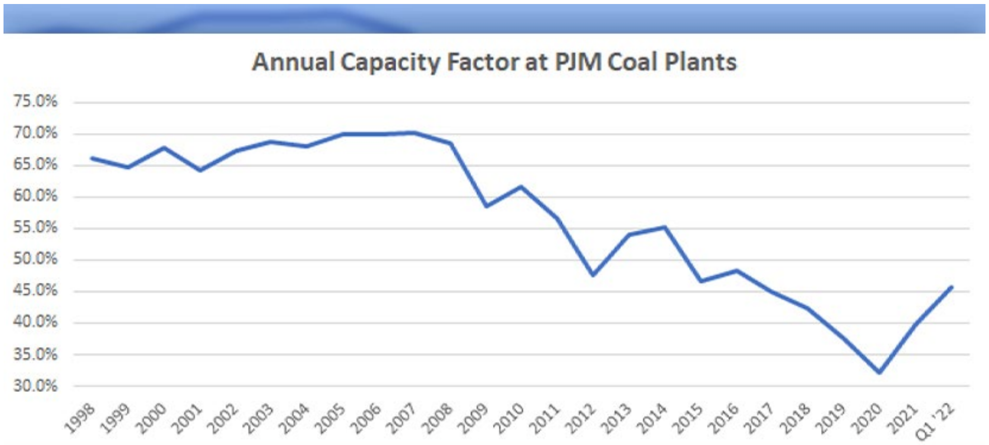
The RTO proposed allowing coal units only to qualify for maximum emergency with between 32 and 240 remaining run hours. Use of the status would be barred under hot or cold weather alerts, or when conservative operations have been declared. PJM also could deny use of maximum emergency for "any reason," including potential thermal or voltage violations, black start concerns or extreme weather.

PJM proposed notifications be made via eDart and Markets Gateway with verbal notification to generation dispatch. "Dispatchers are looking at a lot of data," Pilong explained.

David "Scarp" Scarpignato, of Calpine, said it could be "overkill" to require the notification in so many different channels, with the risk that one might be missed.

"We don't want to create a compliance trap," Pilong said.

Monitoring Analytics' Joel Luna offered the Independent Market Monitor's alternative proposal, saying "we don't want to expand 'MaxE' without some consequences."



PJM coal plants saw their capacity factors drop from more than 65% to below 35% in 2020 before rebounding to 45% in early 2022. | *Energy Ventures Analysis*

The Monitor's proposal would create a new availability status for "fuel conservation." That would allow any committed capacity resource with 10 days or less of inventory that does not qualify for the maximum emergency fuel limit (e.g., not beyond the owner's control, not a temporary interruption, not the result of limited on-site storage) to be made unavailable for economic dispatch.

The catch: Units would forfeit their daily capacity revenues during that status.

Luna said the new availability status is needed because PJM's proposal doesn't change the requirement that the maximum emergency status be the result of physical causes.

"The disruption in the coal market, those are not physical events," Luna said. "Those are decisions plant owners make based on the future. We don't think it warrants the current definition of MaxE.

"We believe our option is better. … Otherwise we still have the same situation with MaxE being driven by physical events — bridges, barges — not a contractual, procurement decision. This allows both PJM and the market seller to allocate that energy when it's needed the most," Luna said.

Becky Robinson of Vistra asked whether units under the IMM's option would see their equivalent demand forced outage rate (EFORd) reduced for future capacity auctions. "If we're not doing that, we're pretending we have more capacity than we do."

"That's a really good point, on how to represent these megawatts in the future," responded Luna.

Tom Hyzinski of GT Power Group said he disagreed with the IMM's proposed penalties "because there is no failure to meet one's capacity obligation — one is still subject to CP penalties, and PJM can deny MaxE status and call the unit for reliability at any time."

Hyzinski said it would be "retroactive ratemaking" to apply the new rules to resources with existing capacity obligations. "If the [Base Residual Auction] has not cleared, and the IMM proposal is in place for that delivery year, then I understand that before I sell the capacity," he wrote in a WebEx message to other meeting participants.

The committee will be asked to choose between the two proposals at its next meeting. ■

PJM Orders Dominion 'Immediate Need' Projects to Serve Load Jump in 'Data Center Alley'

By Rich Heidorn Jr.

VALLEY FORGE, Pa. — PJM officials said last week that "Data Center Alley" in Northern Virginia will require further transmission upgrades in addition to the previously identified $230 million in baseline and supplemental transmission upgrades to support a 4-GW increase in load.

The RTO said it has assigned incumbent Dominion Energy to construct the "immediate need" reinforcements. Dominion is already in the process of constructing 11 "supplemental" transmission upgrades estimated at $197 million and two "baseline" transmission upgrades totaling more than $32 million to address the "unprecedented load growth" caused by the continued growth of power-hungry data centers near Dulles Airport.

PJM's Sami Abdulsalam gave the Transmission Expansion Advisory Committee a *presentation* on the issue July 12, showing that Dominion's load is growing by 3% per year for 2022-2027, all of it from data centers.

Since 2018, Dominion has submitted to PJM 44 supplemental projects to serve more than 2 GW of increased load through the summer of 2025. All told, the RTO expects 4 GW of additional load in the area between 2021 and 2027.

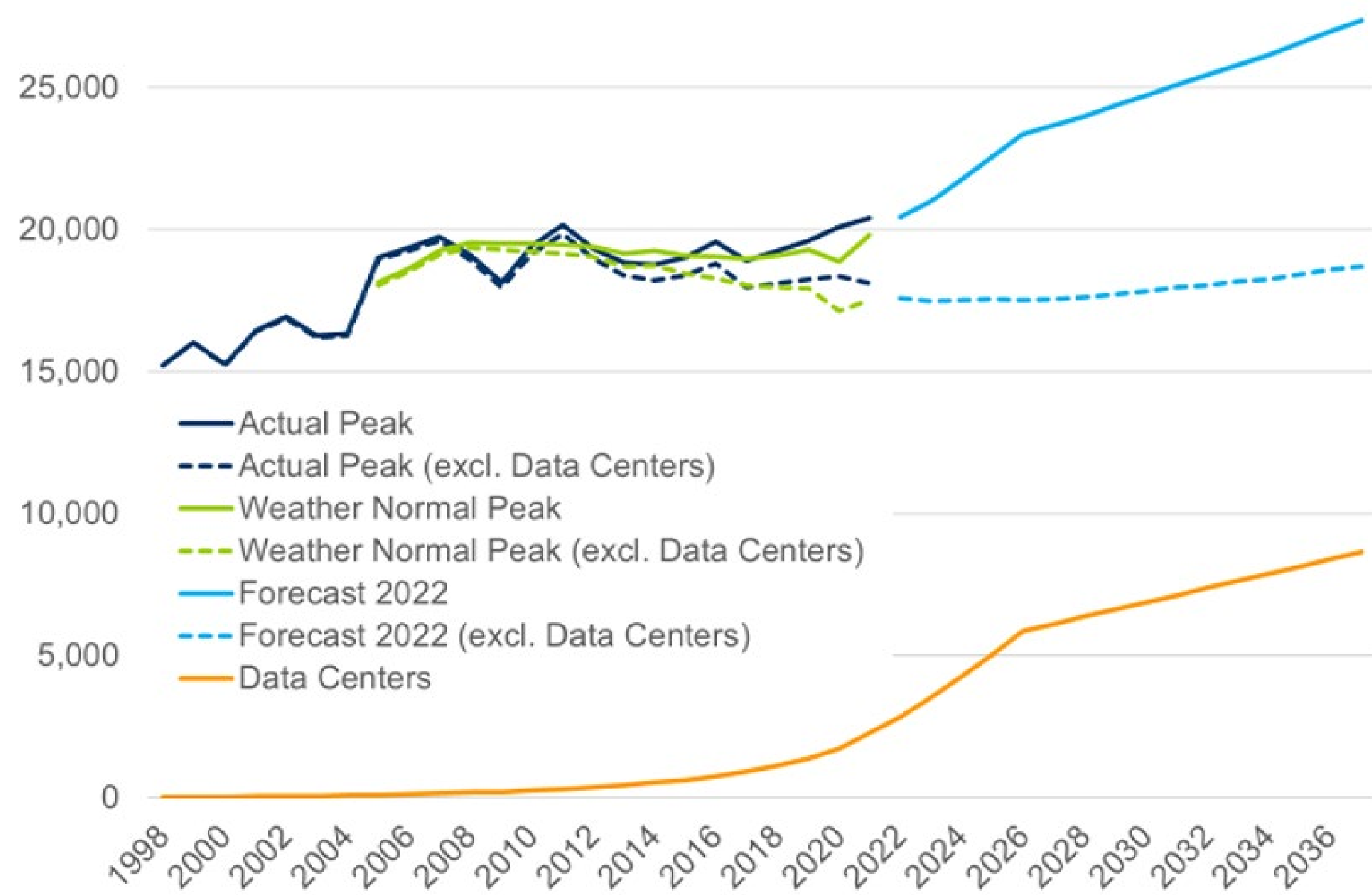
Data center additions listed in the 2022 load forecasts provided by Dominion and Northern Virginia Electric Cooperative (NOVEC) were "noticeably higher" than in their 2021 forecasts, PJM said.

The updated load forecast for the 2027 Regional Transmission Expansion Plan showed that the area would face reliability violations even with the 13 projects in service, with four flowgate violations leading to load drop of more than 300 MW.

"Because the area is constrained on all 230-kV inlet transmission segments to serve the size of load, and data center load has a flat profile throughout the day, power flow control or non-wires solutions are not applicable to solve the identified transmission needs," PJM said.

As a result, PJM declared an immediate need to address reliability violations expected through 2025 and assigned construction responsibility to Dominion, saying a shortened competitive window would result in "delays of about six months."

The immediate-need reinforcements will address violations in the area through 2025. PJM plans to solicit competitive proposals for further reinforcements that may be required beyond 2025. Once a proposed transmission solution is identified, PJM and Dominion will present it to the August 2022 TEAC meeting for first read. ■



Data center additions listed in the 2022 load forecasts provided by Dominion and Northern Virginia Electric Cooperative (NOVEC) were "noticeably higher" than in their 2021 forecasts, PJM said. Dominion's 2022 load forecast predicts a 3% annualized growth rate for 2022-2027, all resulting from data center loads. | *PJM*

SPP News

SPP Twice Extends Record for Peak Demand

WESTMINSTER, Colo. — SPP set two new marks for peak demand last week, wiping out a record that had been set just the week before.

The grid operator set its latest high Friday when its 14-state footprint met 52.03 GW of demand at 4:33 p.m. CT. That bettered the previous mark of 51.5 GW set July 11, which itself broke the previous record of 51.1 GW set July 5. (See *SPP Sets Demand Record amid Midwest Heat*.)

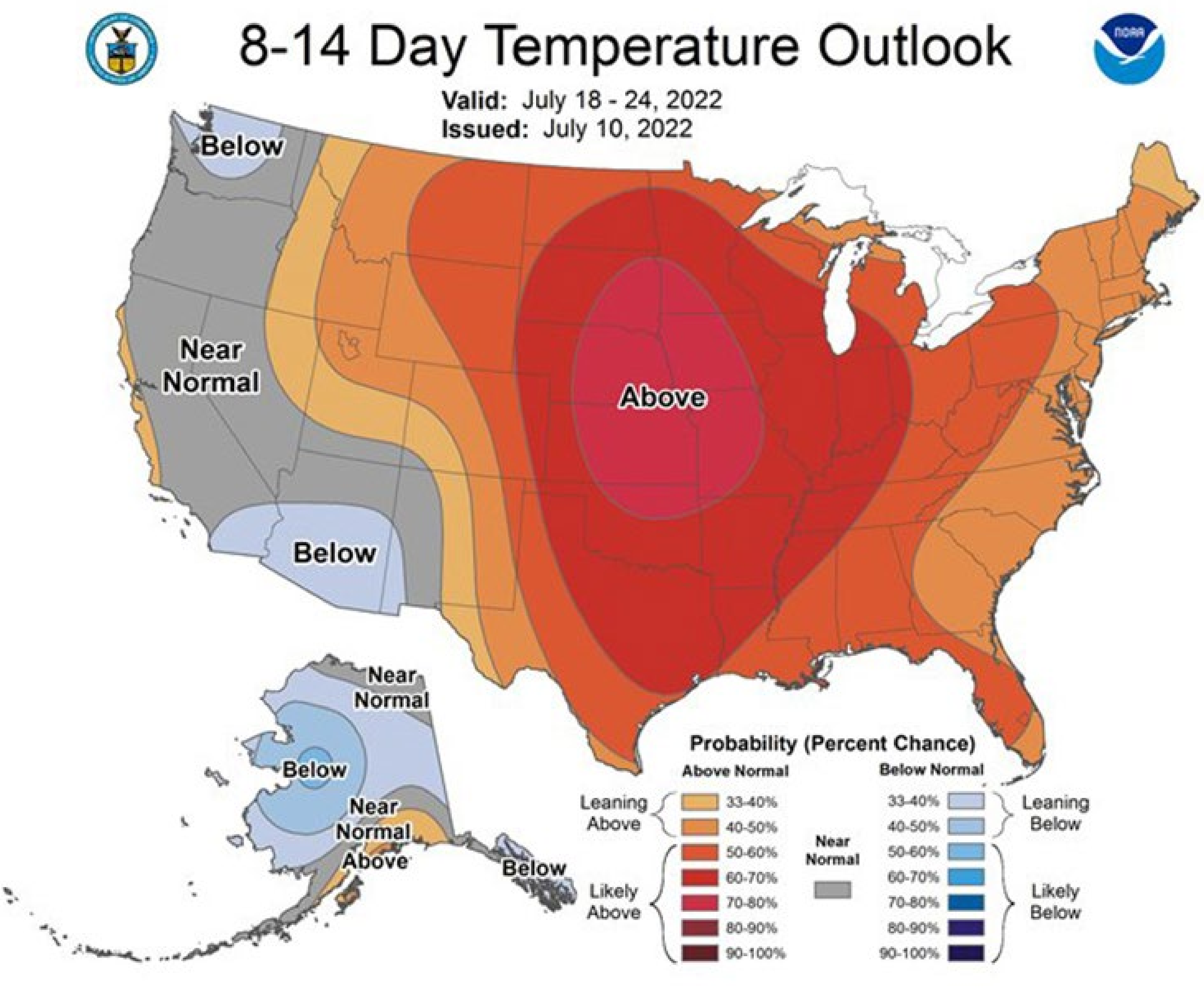
SPP also issued a new conservative operations advisory, effective Monday from 12 p.m. through 10 p.m., because of high demand for electricity and the uncertain availability of some generation resources.

"Summer's not over," Bruce Rew, senior vice president of operations, told the Markets and Operations Policy Committee meeting July 12.

Rew had said SPP would remain in a resource advisory until at least last Wednesday, "if not longer"; that day, the RTO extended the advisory for its entire 14-state balancing authority to Friday at 10 p.m. It said this was necessary "because of the persistence of extreme heat, high electricity use across its region and uncertainty in its wind forecast."

The conservative operations advisory does not require public conservation but is intended as a signal to utilities that they need to operate the system more conservatively to mitigate risks associated with weather, environmental, operational, terrorist, cyber or other events. ■

— Tom Kleckner



NOAA's forecast calls for above-normal temperatures in the Plains next week. | *NOAA*

SPP Strategic Planning Committee Briefs

SPC Debates Non-standard Load's Impact on System

WESTMINSTER, Colo. — An ad hoc group of SPP stakeholders and staff addressing crypto miners and other "non-standard" loads told the Strategic Planning Committee last week that the additional demand could aggravate resource adequacy concerns, yet also serve beneficial functions as well.

"If we really put our heads together and work through the process, there's probably a solution," said NextEra Energy Resource's Matt Pawlowski, a member of the self-labeled "non-task force."

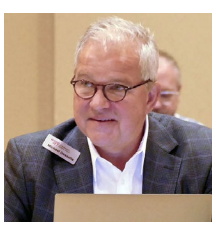
The group has drafted a preliminary report but will let SPP staff assemble a strawman that will be brought back to the SPC in October to identify gaps between the loads and current system processes. Those proposals will likely get farmed out to the Markets and Operations Policy Committee and its working groups.

"This has to be vetted. It's a huge policy issue," Golden Spread Electric Cooperative's Mike Wise said. "These policy implications need to be debated at the SPC."

SPP defines non-standard loads as very large, potentially interruptible loads such as crypto miners, data centers, biofuel and alternative fuel manufacturers, and cannabis grow houses. The loads can be broken down into firm and non-firm load, some of which will be behind the meter.

Since June 21, the grid operator has received 56 requests from such loads to change delivery points, ranging in size from 3 to 1,300 MW and totaling 7.1 GW.

"More of this is likely coming," SPP's chief compliance and administrative officer Michael Desselle said. "If these kinds of loads seeking to locate in low LMP zones concentrate in one particular zone, that only exacerbates resource adequacy concerns."



SPP's Michael Desselle listens to feedback after briefing the SPC on non-standard load additions. | © *RTO Insider LLC*

Desselle said members have expressed concerns that the loads' transient nature could leave the RTO with stranded transmission investments.

Tom Christensen, Basin Electric, makes a point as SPP CEO Barbara Sugg listens. | © *RTO Insider LLC*

However, non-standard loads could also provide demand response if controls allow them to respond adequately, the group said in its draft report.

SPC in April created the ad hoc group to advise it on the issues associated with non-standard load wanting to connect to SPP and its members. (See "Ad Hoc Group to Look at Cryptos," *SPP Strategic Planning Committee Briefs: April 13, 2022*.)

Energy Storage Group to be Retired

The SPC approved the Energy Storage Resource Steering Committee's (ESRSC) retirement and the group's recommendation that multi-use ESR initiatives remain on hold until at least January 2024 and be managed through the normal course of business.

Evergy's Denise Buffington, who chaired the committee, said 25 of 38 initiatives that the ESRSC was responsible for have been completed. The other 13 have been assigned to primary working groups, with most be to be completed by 2025.

Staff last week filed *tariff revisions* with FERC to establish the framework under which an ESR can be considered a transmission asset, including clarifications to their cost allocation, planning, interconnection and market issues. (See "Storage Accepted as Transmission," *SPP Markets and Operations Policy Committee Briefs: Jan. 10-11, 2022*.)

The SPC last year recommended staff and stakeholders continue developing rules that allow ESRs sited as generation resources and as transmission-only assets (SATOA). It also said rulemaking and policy for SATOAs should be completed before finalizing evaluations for multi-use ESRs in what has been labeled a "walk-before-run approach."

Multi-use ESRs are on hold, pending SATOA implementation and additional production experience.

American Electric Power's Richard Ross, a critic of task forces, marked the ESRSC's retirement by presenting one of his coveted Gold Stars of Excellence to Buffington — "With a certificate of authenticity," he said — for closing down the steering committee.

Counterflow Optimization Work Continues

SPP's Micha Bailey told the committee that staff's latest effort to add counterflow optimization (CFO) to the market will continue with a stakeholder workshop this fall to review stakeholder input and best practices from other ISOs and RTOs.

"Some of the stuff they're doing we actually like," Bailey said. "We want to bring that back to workshop for stakeholder feedback."

"Those conversations are really helpful. That's going to potentially lead to some better practices here," Pawlowski said, noting that his company operates in every other organized market.

Staff will also share results of the survey it conducted in May of several stakeholder groups on CFO and other congestion-hedging proposals. The workshop will be conducted before the October set of governance meetings.

Stakeholders have been unable to come to a consensus on how to add CFO to the market. The initiative was recently handed off to the SPC. (See "Counterflow Optimization not Dead Yet," *SPP Board of Directors/Markets Committee Briefs: April 26, 2022*.)

The Holistic Integrated Tariff Team recommended three years ago that counterflow optimization, limited to excess auction revenue, be added to SPP's market mechanism that hedges load against congestion charges. The process, which keeps system transmission flows between two points in balance, was meant to address concerns about how congestion rights instruments are awarded and the current process's efficiency.

Competitive Project Improvements OK'd

The SPC approved five process-improvement recommendations from the task force working to improve SPP's transmission owner selection process (TOSP) under FERC Order 1000.

The recommendations are:

- Requiring addendums to reconciliation invoices to clarify true-up cost calculations and the invoices;
- Adopting a cost/cap/guarantee disclosure table to improve their transparency and impacts to quarterly tracking;
- Adding a scoring methodology table applicable to all scoring categories and sub-categories;
- Preventing the industry expert panel (IEP) scoring competitive bids from awarding additional points for early in-service dates or guarantees; and
- Requiring the IEP's public report be posted no later than 21 calendar days prior to the Board of Directors meeting considering the competitive project's approval.

The TOSP Task Force has made other process improvements after each of SPP's competitive project solicitations. The RTO's board has awarded four competitive projects since 2016, the most recent coming in April when NextEra Energy Transmission won a bid for a $55 million, 345-kV facility in Oklahoma. (See *SPP Board of Directors/Markets Committee Briefs: April 26, 2022*.)

The task force will draft the tariff revision requests' language and work to gain the appropriate stakeholder and governance approvals, with the October meetings as a target. It will also continue working on the remaining 11 improvement items. ■

— Tom Kleckner

SPP Markets and Operations Policy Committee Briefs


SPP staff and stakeholders prepare for the July MOPC meeting in Colorado. | *© RTO Insider LLC*

RCAR III Shows Dramatic Improvements in all Tx Zones

WESTMINSTER, Colo. — SPP's third Regional Cost Allocation Review (RCAR) of the regional and zonal allocation methodology's reasonableness left several members dinged by the first two reports in a cautious, yet celebratory mood during last week's Markets and Operations Policy Committee meeting.

"We're not popping the champagne yet," said Jeff Knottek, director of system planning and compliance for City Utilities of Springfield (Mo.). He was among several members who have requested meetings with the RTO's staff to better understand how the new numbers were derived.

CUS was the only utility below a benefit-to-cost ratio threshold of 0.80 in its transmission zone after the first RCAR in 2012. It was joined by five other utilities who failed to meet the 40-year present values of the estimated benefit metrics and costs in 2016's RCAR II.

However, the preliminary RCAR III review pegged CUS' ratio at 10.65, third among all pricing zones.

"It feels pretty good to be a winner," said Empire District Electric's Aaron Doll, whose zone went from a 0.60 to a 6.04 in the last two RCARs. "Empire would be interested in meeting with SPP staff to understand how our B/C ratio increased tenfold with little to no investment. … We're a little bit skeptical the increase was so substantial without the investments commensurate with that."

SPP General Counsel Paul Suskie said the Regional Allocation Review Task Force, comprising SPP regulators and members, took a hybrid approach to RCAR III. Staff used actual market runs with and without highway/byway transmission and took a planning-based approach for approved upgrades not in service for at least two years.

The review's preliminary operational results show significant B/C results for the region and all pricing zones. Staff used 538 of 741 highway/byway upgrades, totaling $4.6 billion of $6.4 billion in upgrade costs. They said it is unlikely any remedies will be needed.

Suskie said the real-life models were a contrast to the first two RCARs, which were more "theoretical, what we thought the system would look like." That resulted in lower B/C ratios for CUS, Empire and others.

"For instance, we said in 2020 [that] we would have 17 GW of wind in 2022. Today, we have 31 GW," Suskie said. He pointed out that the recent run-up in natural gas prices also created higher ratios.

MOPC endorsed the RARTF's recommendation to direct staff to finalize the report based solely on operational results. When the report is brought back to the committee in October, members can then determine if the full planning process is needed to supplement the operational result.

MOPC Keeps SPS' Tx Alternatives Alive

Committee members endorsed two projects as potential solutions for a 345-kV double-circuit transmission line in eastern New Mexico's Permian Basin region.

They sided with staff's recommendation to issue a notification to construct following further evaluation of Southwestern Public Service's proposed Crossroads-Phantom project, a 150-mile line estimated to cost $410 million.

MOPC also endorsed a NextEra Energy Resources' motion that Crossroads-Phantom would be a viable alternative to another proposed project line in the same region, the 143-mile, 345-kV double-circuit Crossroads-Hobbs-Roadrunner line. The $395 million project was approved as an alternative by both the Transmission and Economic Studies working groups over its operational flexibility and lower cost to SPS.

The votes served as a compromise following a discussion over whether to vote on the two different projects separately or together, and whether to even conduct the vote. That left some members frustrated enough to suggest MOPC should just tell the Board of Directors to decide for it.

"We're abdicating our responsibility," Midwest Energy's Bill Dowling said.

The original proposal received 80% support, while NextEra's suggestion barely cleared the 67% threshold.


Jarred Cooley, SPS | *© RTO Insider LLC*

"At the end of the day, NextEra and other want to see steel in the ground," NextEra's Matt Pawlowski said.

Jarred Cooley, SPS' director of strategic planning, called in to the meeting to throw his

SPP News

company's support behind the Crossroads-Roadrunner option. He said adding a substation at Hobbs gives direct access to reactive reserves for the load pocket and offers voltage support on the pocket's north and south sides.

"Apples to apples, it has slightly better economics; it's a slightly cheaper line; and routing the line through the Hobbs substation breaks up an extremely long, 150 mile transmission line that would span pretty much the entire New Mexico territory," he said. "This will help our area operationally grow as the system continues to grow in that area."

The Crossroads-Phantom project was originally part of the 2021 Integrated Transmission Planning (ITP) report that was approved in January. However, MOPC pulled the project out of the portfolio when two stakeholder groups said load-projection errors had been discovered late in the planning process. (See *SPP Markets and Operations Policy Committee Briefs: Jan. 10-11, 2022*.)

Questions to Engineers Require Care

Golden Spread Electric Cooperative's Natasha Henderson learned the hard way not to ask a group of engineers a question with a literal answer.

Fresh off a Hawaiian vacation that was sandwiched between SPP meetings and focused on the three presentations she was about to deliver to MOPC, Henderson entered the meeting room looking for her seat. She walked up to a group of fellow stakeholders and jokingly asked where she was.

The group was more than happy to help.

"You're right here!" responded one. "You're with us!" another said.

Henderson eventually found her seat on her own.

NRDC Becomes SPP's 113th Member

MOPC welcomed to the table Natural Resources Defense Council's Christy Walsh, director of federal energy markets, who represented the organization as it became SPP's 113th member. The RTO eliminated its exit fee for non-transmission owners several years ago, opening the door to environmental groups and other nonprofit organizations. (See *FERC Tells SPP to End Exit Fee for Non-TOs*.)

Walsh, a FERC staffer for almost 20 years, is only serving until the environmental advocacy group can hire a fulltime staffer to represent it before RTOs.

Changes for Tx Evaluations

MOPC endorsed a revision request (*RR452*) from the Transmission Working Group that adds a standardized process for evaluating projects proposed by TOs for reasons other than meeting SPP regional criteria or meeting a limited subset of local planning criteria evaluated in the ITP.

The change will allow TOs to perform their own analysis and provide it to staff for review. If SPP performs the studies, TOs must sign an agreement, pay a deposit and cover all study costs.

The more "robust" process also includes the implementation of zonal planning criteria recently approved by FERC. The revision establishes an annual process for each transmission pricing zone to develop a single set of uniform zonal criteria to evaluate zonal reliability upgrades in regional planning. (See *FERC Accepts SPP's 2nd Try at Zonal Planning Criteria*.)

Members also unanimously approved a consent agenda included three RRs:

- *RR484*: includes surety bonds as a form of "financial security" within the tariff to secure all types of financial transactions, including transmission congestion rights and virtual energy. Surety bonds can provide a lower cost entry point for creditworthy customers as compared to a letter of credit.
- *RR489*: identifies business practice and ITP manual changes to ensure that transmission service and ITP base reliability models' dispatch are accounting for the granted amount of interconnection service or surplus interconnection service to multiple resources behind the same point of interconnection. The RR also identifies an ITP base reliability dispatch approach for batteries that have been granted transmission service for charging purposes.
- *RR496*: adds minor and non-substantive missing language, primarily modifying settlements, that are necessary to accurately implement *RR449*.

The committee also approved four sponsored upgrade studies. SPP reliability assessments found no system impacts on:

- NextEra Energy Resources' upgrade of terminal equipment on two 161-kV lines near Warrensburg, Mo.;
- Invenergy's proposal to build a 345-kV line between two substations in West Texas;
- Invenergy's upgrade of two 345/230-kV transformers in South Dakota to a 581-MVA rating; and
- Oklahoma Gas & Electric's reconductoring of a transmission line to increase their normal and emergency ratings of the lines while replacing aging assets. ■

— Tom Kleckner

Description	Study Level E&C Cost ($2021 M)	40-Yr NPV Cost ($2021 M)	F1			F2		
			Emer. Energy	40-yr. B/C	Net APC Benefit ($2021 B)	Emer. Energy	40-yr. B/C ($M)	Net APC Benefit ($2021 B)
C-P	$410	$630	3,803	4.16	$2.62	5,620	4.51	$2.84
C-H-R	$395 (-$15)	$607 (-$23)	2,848 (-955)	4.54 (+0.38)	$2.78 (+$160 M)	6,311 (+691)	4.91 (+0.4)	$2.98 (+$140 M)
C-P + Rebuild	$418	$643	484	5.01	$3.22	1,407	5.24	$3.37
C-H-R + Rebuild	$403 M (-$15 M)	$620 (-$23)	1,685 (+1,201)	4.97 (-0.04)	$3.08 (-$140 M)	4,591 (+3,184)	5.20 (-0.04)	$3.22 (-$150 M)

Comparisons between the Crossroads-Phantom and Crossroads-Hobbs-Roadrunner projects | *SPP*

Company Briefs

Ford, SK On Finalize Plans for EV Battery Plant at BlueOval City

Ford and SK On last week finalized plans for a joint venture EV battery plant at BlueOval City in Haywood County, Tenn.

The two companies will hold equal ownership in the venture.

Ford and SK On announced plans in September for the $5.6 billion BlueOval City project to produce the next generation of F-Series electric trucks and EV batteries at a 3,600-acre site in Stanton.

More: *Memphis Commercial Appeal*

GM, Pilot to Develop EV Charging Network

General Motors and travel operator Pilot last week said they will develop a national network of 2,000 EV charging stalls at travel centers to make it easier to recharge near highways.

GM and Pilot said the program is targeting charging installations at 50-mile intervals. It is part of its GM's previously announced $750 million investment in EV charging infrastructure.

More: *Reuters*

Walmart to Buy EVs from Canoo

Walmart last week said it has agreed to buy 4,500 electric vans from manufacturer Canoo to deliver online orders.

Canoo said it expects to start making its Lifestyle Delivery Vehicles toward the end of the year at its manufacturing plant in Pryor, Okla., with the expectation that they will start making deliveries in 2023.

The deal includes an option for Walmart to buy up to 10,000 of the vehicles. Financials were not disclosed; however, Canoo said in a May earnings call that its Lifestyle Vehicles would have a targeted price of $34,750 to $49,950.

More: *Arkansas Democrat Gazette*

Panasonic to Build $4B EV Battery Plant in Kansas

Panasonic last week announced it has chosen Kansas for the location of its new $4 billion EV battery manufacturing facility.

Panasonic said it chose Kansas for its proximity to Texas (home of Tesla) and favorable tax treatment.

The facility will be used to manufacture a new, larger EV battery that can extend the driving range of Teslas.

More: *The Journal Record*

Equinor to Buy Storage Developer East Point Energy

Norwegian energy group Equinor ASA last week agreed to acquire East Point Energy, a U.S. battery storage developer with a 4.1-GW pipeline of early to mid-stage projects mainly on the East Coast.

The purchase is expected to be completed in the third quarter of the year, with East Point Energy becoming a subsidiary. No financial details were released.

More: *Renewables Now*

ATE Announces New Board Members

The Alliance for Transportation Electrification last week appointed three new faces to its board of directors: Louis Tremblay, Hank Adams and Lon Huber.

Tremblay is the president and CEO of EV charging network operator FLO. Adams is the vice president of corporate development for Southern Company. Huber is the senior vice president of pricing and customer solutions for Duke Energy.

More: *ATE*

Lordstown Motors Names Hightower CEO

Electric-vehicle firm Lordstown Motors last week replaced its CEO with insider and automotive industry veteran Edward Hightower in a management shake-up aimed at ramping up efforts to start production of its pickup truck.

Hightower takes over for Daniel Ninivaggi, who will become executive chairman.

Lordstown also named Donna Bell, a former Ford executive, as its executive vice president of product creation, engineering and supply chain.

More: *Reuters*

Hazelton Named CFO of Leeward Renewable Energy

Leeward Renewable Energy (LRE) announced it has named Greg Hazelton its new chief financial officer.

Hazelton joined LRE's senior leadership team and will lead its financial operations, which includes finance, accounting, financial reporting, treasury and financial risk management.

Hazelton was previously the executive vice president and CFO of Hawaiian Electric Industries where he oversaw corporate financial strategy and performance.

More: *Leeward Renewable Energy*

Federal Briefs

NRC Sees No Environmental Risk from Nuclear Waste Storage in NM

The Nuclear Regulatory Commission last week released a report saying it found no environmental concerns in the construction or operations of a nuclear waste storage facility in New Mexico.

Holtec International proposed the facility, which would temporarily hold up to 100,000 metric tons of spent nuclear fuel rods at the surface in a remote area near the Eddy-Lea county line. Holtec applied for a license from the NRC, which will ultimately make the decision on licensing the storage site.

Such a disposal facility does not exist in the U.S. One was proposed at Yucca Mountain, Nev., but it was blocked by the federal government amid public outcry and opposition.

More: *Carlsbad Current-Argus*

TVA Seeks 5 GW of Carbon-free Energy

Tennessee Valley Authority last week issued a request for proposals (RFP) for up to 5 GW of carbon-free energy.

The RFP is seeking to procure up to 5 GW of carbon-free resources with commercial operation dates between 2023 and 2029. TVA is also seeking proposals for battery energy storage systems paired with clean energy resources, standalone BESS, and hybrid combinations. The proposals must be submitted by Oct. 19.

TVA's plan is to reduce carbon from 2005 levels by 70% by 2030, 80% by 2035, and to be net-zero by 2050.

More: *pv magazine*

Enviro Groups Push Senate to Confirm EPA Enforcement Chief

Leaders from the Environmental Defense Fund, Earthjustice, the League of Conservation Voters, the National Wildlife Federation and the Natural Resources Defense Council last week released a statement calling on the Senate to prioritize the confirmation of David Uhlmann as the EPA's enforcement chief.

The groups said confirming Uhlmann will enable the agency to better enforce existing climate rules after the Supreme Court recently took away a major regulatory tool to prevent power plant emissions.

The EPA last year referred its lowest number of criminal cases to the Justice Department in decades.

More: *The Hill*

State Briefs

ALABAMA

Alabama Power to Increase Rates

Alabama Power last week announced the average household could see a 5% ($6) increase on its energy bill beginning in August.

Communications Specialist Anthony Cook attributed the increase to the "rising cost of fuel at both the national and international level."

However, Cook said because of the "lower than forecasted" storm recovery costs in 2021, customers who use 1,000 kWh a month or more would receive a one-time credit of $19 on their July bill.

More: *The Gadsden Times*

COLORADO

EPA Agrees with Air Pollution Whistleblowers on IG Complaints

The state's EPA last week agreed with many claims by air pollution division whistleblowers that the state was issuing permits without proper modeling or review. The agency recommended revision of at least 11 permits in dispute.

Three Air Pollution Control Division employees filed a complaint with the EPA's Office of Inspector General last year saying their managers endangered the health of residents by unlawfully approving noxious gas permits for companies without federally mandated modeling or monitoring. They allege their managers ordered them in mid-March 2021 to stop performing modeling required by the Clean Air Act.

Division leadership has since changed hands, and the EPA's report on the complaints acknowledged the state has already agreed to implement some of the recommendations in its modeling and permitting program.

More: *The Colorado Sun*

Regulators Approve 3 Utilities' Clean Energy Plans

The Air Pollution Control Division last week approved clean energy plans for Colorado Springs Utilities, Holy Cross Energy and Platte River Power Authority.

The plans detail how each utility will generate electricity in coming years, including what percentages will come from coal, natural gas, hydro power, solar and wind, and how many tons of carbon emissions each source will create.

The approvals come despite objections from environmental groups, which claim the plans include vague promises of green electricity and did not account for 200,000 tons of coal emissions.

More: *The Colorado Sun*

FLORIDA

Florida Power & Light Drops Winter Power Proposal

Florida Power & Light last week filed a notice at the Public Service Commission that said it was withdrawing a proposal that would have used a severe winter storm in 1989 as the basis for future power plants.

Under the proposal, the 1989 storm would have factored into plans for expanding the capacity of power plants and making changes to handle peak demand during the winter. However, the proposal drew opposition from the Office of Public Counsel and other groups that claimed it could lead to costly projects.

FPL said it developed the proposal after studying massive outages caused by cold weather in February 2021 in Texas; it also cited the state's 2010 winter storm.

More: *The News Service of Florida*

GEORGIA

Supreme Court Won't Hear Challenge to Georgia Power's Coal Ash Plan

The state Supreme Court last week decided against hearing a challenge of Georgia Power's coal ash plan and will allow the utility to move forward with charging customers for recovery costs.

A case brought by the Sierra Club argued that Georgia Power mishandled its coal ash and that costs incurred to permanently store the material were imprudent and should not be recoverable. It asked the supreme court to review an appeals ruling affirming the Public Service Commission's approval of a 2019 plan that allowed Georgia Power to bake costs associated with closing its ash ponds into rates. However, after a Fulton County Superior Court judge and the Georgia Court of Appeals rejected the legal challenge, the Supreme Court said it would not hear the case. The decision means rates approved by the PSC will remain in place.

Georgia Power's estimate of how much it will cost to close all its ash ponds has grown from $7.6 billion in 2019 to nearly $9 billion.

The PSC will decide how much the utility can charge customers, while Georgia Power has signaled it will ask for an increase of about 12%.

More: *The Atlanta Journal-Constitution*

INDIANA

St. Joseph County Council Approves Construction of Solar Farm

The St. Joseph County Council last week unanimously approved the construction of a $165 million solar farm in Olive Township.

Lightsource BP will develop the project.

More: *WNDU*

IOWA

Fremont County Approves Wind Farm

The Fremont County Board of Supervisors last week unanimously approved Invenergy's application for its Shenandoah Hills wind project.

Officials in Page County are still reviewing the application.

More: *Radio Iowa*

TEXAS

EPE Rate Increase Settlement Filed with PUC

El Paso Electric last week filed a rate settlement with the Public Utility Commission that substantially lowers the rate increase request it made a year ago.

Under the agreement, the average residential bill would increase $1.80 per month — down from the $11.76 monthly increase originally proposed by the utility. The new rates would become effective Aug. 1.

The PUC must approve the agreement before it can become final.

More: *El Paso Times*

WISCONSIN

Alliant Offers Payments if Customers Let it Control Thermostats

Alliant Energy is offering to pay customers $25 if they let the utility control their home thermostats during peak electrical or gas demand in the summer and winter.

Alliant hopes to enroll 7,000 customers with internet connected smart thermostats in its "Smart Hours" program by next year. The company is offering sign-up bonuses of $25 and annual payments of $25 in exchange for allowing it to adjust the temperature of homes by a few degrees up to 20 times per year.

Documents filed with the Public Service Commission estimate the program has the potential to reduce peak electrical demands by up to 6 MW by 2023.

More: *Wisconsin Public Radio*