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Stakeholder Soapbox

Midwest Lessons on the Value of Transmission Independence and Competition

By Devin Hartman

Devin Hartman, R Street Institute | *R Street Institute*

The Midwest has become ground zero for the future of transmission policy. Reliance on incumbent transmission owners to dictate state policy and regional transmission practices in MISO has led to higher costs, stifled innovation and a backlash to grid expansion. By extension, the reliability and environmental benefits of grid expansion hang in the balance. Implications for state legislatures, utility commissions and FERC are clear: inject more independence into transmission practices and enable competition to flourish.

The Midwest's economy has succeeded when good governance and fair competition prevail. Transmission is no different. Upon the national introduction of transmission competition, competitive projects averaged 40% below initial cost estimates, whereas non-competitive projects averaged 34% above initial estimates.[1] An independent assessment found a 22 to 42% cost savings from competition in MISO specifically.[2] The problem is that competition and advanced technologies are hardly used because incumbents evade an incomplete regulatory framework that they helped design.

Methods and technologies that expand grid capacity and lower costs are sternly opposed by cost-of-service utilities eager to maximize rate base. For example, an upper Midwest pilot on topology optimization, which reroutes grid congestion, could scale up to save regional consumers hundreds of millions of dollars annually, improve grid resilience and increase wind integration.[3,4] Unsurprisingly, expanding this technology is attracting interest from consumers, clean energy interests, the Organization of MISO states and the MISO independent market monitor (IMM).[5,6] Yet one obstacle remains: incumbent utilities, which actively suppress efforts to use existing rate base more efficiently.

FERC issued a rule last December to address a similar problem: utilities were failing to implement best practices in transmission line ratings. A key motivator of the decision was analysis by MISO's IMM saying that such practices would have saved MISO customers over $100 million in 2019 and 2020 alone.[7] Such analyses are the exception, not the rule, and speak to the imperative of more robust independent transmission oversight.

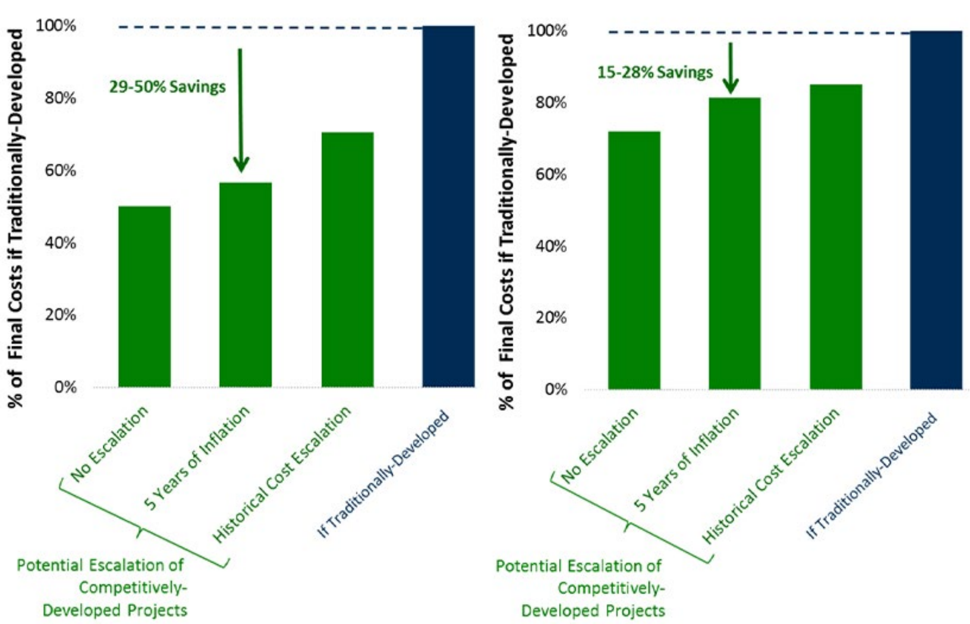
IMMs are also noting that incumbent TOs hold outsized influence in transmission planning processes, such as shaping planning inputs to their advantage, not actual values.[8] This contributes to planning processes that are short-sighted and do not reflect future generation.[9] Incumbents' influence is further evident in the technical exclusions of transmission projects from competition solicitations. This has enabled incumbents to evade regional planning processes subjected to competition and build local projects instead, where they face neither competition nor economic regulatory scrutiny.

Unfortunately, this has led some to blame competition for the lack of regional transmission development, rather than the faulty regulatory framework that encourages problematic incumbent behavior. Make no mistake, reverting to exclusive incumbent control will undermine transmission expansion. Those tempted to believe that incumbents streamline transmission development need only examine MISO South, where incumbent utilities obstructed plans to build transmission that would boost severe weather resilience and enable cleaner, lower-cost energy access.[10]

Given the advantage of competition, it may seem paradoxical that some Midwest legislatures have passed anti-competitive "right of first refusal" (ROFR) laws to grant incumbents exclusive rights to build, own and operate transmission assets. But the recipe for this is no surprise; the concentrated interests of incumbent utilities exert a lobbying effort that overwhelms the voices of dispersed interests, namely consumers. In Michigan, the most recent state to pass a ROFR, incumbents overrode opposition from the Michigan Chemistry Council and conservative Mackinac Center for Public Policy.[11] Incumbent utilities are also behind new proposed ROFR legislation in Wisconsin, which the Wisconsin Industrial Energy Group has called "really terrible public policy" with billions at stake for customers.[12] As noted by Americans for Tax Reform, ROFR is effectively "a regressive tax hike on individuals, families and employers" in the Midwest.[13]

States have the right to shoot themselves in the foot. But they cannot harm their neighbor. ROFR for regional transmission projects unquestionably harms interstate commerce. The Wisconsin chapter of Americans for Prosperity remarked that state ROFR likely violates the Dormant Commerce Clause of the Constitution.[14]

Tellingly, out-of-state groups resist other states' ROFRs. For example, the Iowa Department of Justice Consumer Advocate filed a legal brief challenging Minnesota's ROFR.[15] Given the recency of most ROFRs, few developments have transpired to demonstrate the



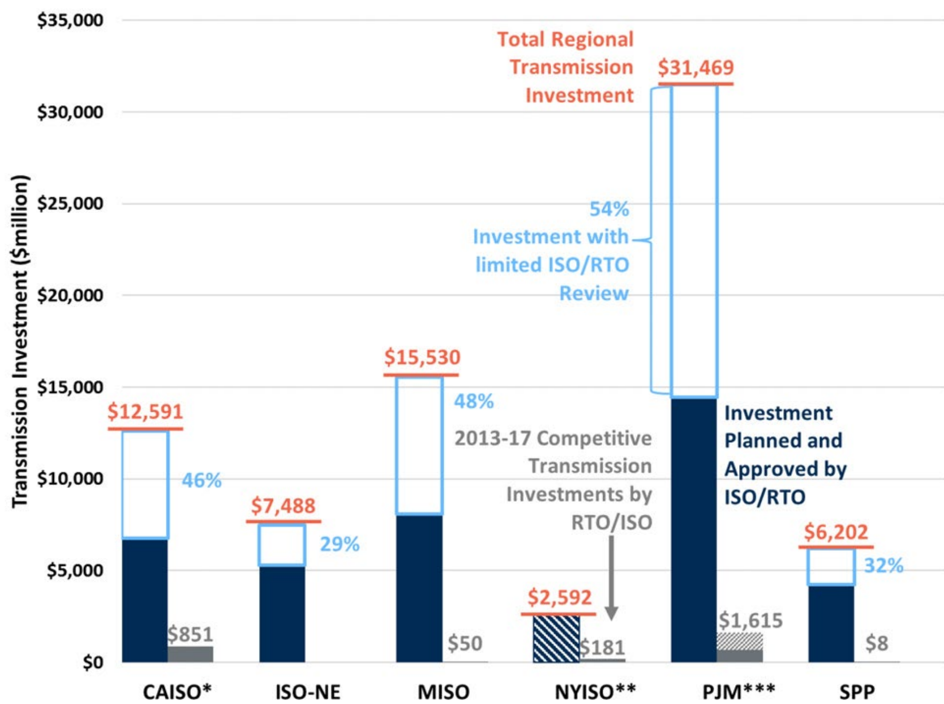
Cost savings for competitive projects in CAISO and MISO | *The Brattle Group*

Stakeholder Soapbox

harm it causes, which limits court challenges under the Dormant Commerce Clause. But MISO's new transmission cost sharing filing before FERC may illuminate ROFR's premium.[16] This will amplify the legal case against ROFR and seed stakeholder resistance to anti-competitive grid expansion.

As resistance mounts, it is clear that ROFR increasingly undermines the interstate cooperation needed for regional projects. States like Illinois have resisted paying for the burdens of other states' anti-competitive transmission laws.[17] Left unresolved, more litigation and controversy is unavoidable. And it is about to get a whole lot worse: MISO's new Long Range Transmission Planning process is poised to unveil over $10 billion in transmission expansion, which may verifiably place ROFRs' price tag in the billions.[18]

As the clock ticks, MISO stakeholders and FERC should call for a more independent planning process and robust Monitor oversight while dramatically narrowing the technical exclusions for competitive projects. What exclusions remain, such as a voltage exemption for local projects, should be subjected to regulatory scrutiny under demonstrated prudence reviews with equivalent rate treatment for incumbent and non-incumbent suppliers.[19] This will improve the quality of local projects and reduce incumbents' use of regulatory arbitrage between regional and local project selection.



FERC-jurisdictional transmission investments with full and limited stakeholder review within ISO/RTO regional planning processes (2013-2017) | *The Brattle Group*

State legislatures should prevent and repeal ROFR laws to benefit themselves and their neighbors. If this does not eradicate ROFRs outright, FERC will have to step in to prevent interstate harm. The law is straightforward. The politics are not. Yet state commissions have already broken the ice by calling on FERC to encourage transmission competition.[20] FERC need only ask them how. ■

Devin Hartman is director of energy and environmental policy for the R Street Institute.

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NARUC Winter Policy Summit

NARUC Panel: Plan for Climate Change

By Amanda Durish Cook

On the first anniversary of Winter Storm Uri's gut punch to the Midwest and Texas, industry experts discussed how to prevent climate change from setting off future mass blackouts.

The panel Feb. 14 was part of the National Association of Regulatory Utility Commissioners' Winter Policy Summit.

Texas-based energy consultant Alison Silverstein said Texans will be paying for the storm's destruction in their bills for the next 20 years "without that ever making a difference" in grid reliability "or preventing the next disaster."

Silverstein said it's time for grid planners to start thinking about not "if it could happen, but when it will happen here." She said the grid needs to be reinforced to handle more regular extreme weather and that using historical weather events is "no guide" in planning for future events.

"This requires us being very, very paranoid," Silverstein said. "The threats are radically different than today." She called for a different "scope of reference" and analyzing the costs of not making investments.

"Nobody was spared. It seemed that if you were in the area, you were going to suffer," David Ortiz, acting director of FERC's Office of Electric Reliability, said of power outages caused by last February's storm.

Ortiz said the "simple" winterization of plants could have cut generation outages by about 50% and 60% in SPP and ERCOT, respectively.

"We have to remember that efficiency and resilience are enemies of each other," said MISO President Clair Moeller, appearing on behalf of the ISO/RTO Council. He noted that resiliency requires advance fuel contracts and extra megawatts in capacity.

Moeller said RTOs and ISOs are considering a variety of strategies to make their generation fleets more available.

"Some of it's a carrot; some of it's a stick. Some of it's an orange stick," he joked.

Moeller said it's clear that grid operators need higher reserve margins in the winter. "Big risk hours aren't all on the peak period, and haven't been for a while," he said.

"It's tremendously important to move away from this peak planning," Ortiz agreed.

Moeller said coal and gas fuel supplies continue to be a concern, with the coal supply chain weakening to where only firm contracts are fulfilled with any degree of certainty. He pointed out that MISO's Midwest region still relies on a 50% coal mix during the winter.

Natural gas generation operators aren't ready for the flexibility that RTOs are going to start asking of them, Moeller said. He said gas-electric coordination will become even more important going forward.

Silverstein said conversations following the storm focused intensely on generation's winterization and ignored that properly insulating customers' homes could have alleviated demand. She said poorly-insulated Texas homes and their use of resistance heating contributed to the event's severity.

Ortiz also cautioned against "staying on only the supply-side of the equation."

"There's a tremendous amount that can be done on the demand side," he said.

Silverstein said more state regulatory bodies must devise meaningful demand-management programs.

Moeller said the ensuing "blame game" and court battles following last year's winter storm are unhelpful. He also said data requests to MISO following the event were daunting and said a better organized data-sharing method would be useful.

"People are betting their lives and their livelihoods on us getting this right," he said. ■

MISO President Clair Moeller (bottom right) speaks during a NARUC panel Feb. 14. | *NARUC*

NARUC Transmission Panel: Leave No Megawatt Behind

Decarbonizing Grid Means Optimizing Technology, Rights of Ways, Collaboration

By K Kaufmann

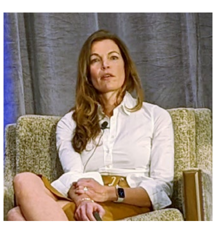
WASHINGTON—With hundreds of gigawatts of solar, wind and storage sitting in interconnection queues across the country, state regulators are increasingly being faced with the conundrum of how to get more clean energy on already congested power lines.

At least part of the answer lies in a range of new technologies and strategies for optimizing existing distribution and transmission lines and rights of way, according to speakers on a Feb. 13 panel at the National Association of Regulatory Utility Commissioners' (NARUC) Winter Policy Summit in D.C.

David Townley, CTC Global | *© RTO Insider LLC*

For example, David Townley, director of public policy for CTC Global, pitched for advanced conductors — like the ones his company produces — as "the fastest, lowest-cost way to add substantial capacity to an existing system."

These conductors — wires that allow more electricity to flow on a system — use a "core made of carbon composites [that are] much lighter than the steel core of the conventional technology," Townley said. "You can literally change wire for wire … but now you can upgrade the capacity on that line and increase the efficiency [and] lower the line losses immediately as soon as you energize that line."



Allie Kelly, The Ray | *© RTO Insider LLC*

Allie Kelly, executive director of The Ray, an Atlanta-based nonprofit, believes that "the highway right of way is the solution that has been hiding in plain sight. The next-generation highway seeks to leverage that public asset — the public land and right of way — to enable and clear the way for new transmission development and construction," she said.

Looking toward the electrification of commercial fleets, Kelly said, charging hubs for those vehicles are likely to be located adjacent to highways. "So, this is actually a very practical solution because you're utilizing the right of way of the highway to provide the energy that will be required by these heavy-duty fleets."

The Ray also promotes siting solar in highway rights of way, with an *online mapping tool* aimed at locating interstate interchanges that could be used for solar.

Patricia Hoffman, DOE | *© RTO Insider LLC*

"We really need to have a dialogue and a conversation with the states, with the utility commissions, with developers, looking at existing infrastructure," said Patricia Hoffman, principal deputy assistant secretary of the Department of Energy's Office of Electricity. "Where can we maximize existing capacity? Where do we need to have additional capacity transfers across the United States so that we can develop the renewable energy but also get [it] into the markets in the most efficient and effective way possible?"

Building a Better Grid

Hoffman provided an overview of DOE's thinking on transmission and the funding and financing opportunities made available under the Infrastructure Investment and Jobs Act (IIJA).

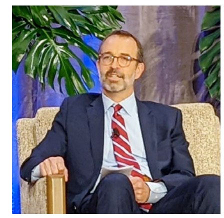
The department's recently announced Building a Better Grid initiative includes integrating existing rights of way into national transmission planning, and Hoffman said collaboration will be key for achieving the "early wins" that optimizing existing transmission with grid-enhancing technologies (GETs) can produce. (See *DOE to Tackle Tx Siting, Financing, Permitting in Better Grid Initiative*.)

Looking at how GETS may change systems operation is yet another opportunity, Hoffman said. "How do we look at the operation of the system so that we get those most out of the topology we have?"

On the funding side, the IIJA includes $5 billion for system hardening and upgrades and another $5 billion for "innovative demonstration projects" that improve grid resilience, Hoffman said. It also authorizes DOE to become an "anchor tenant," purchasing capacity on transmission projects, and to directly finance projects to get them "across the finish line."

While not talking directly about the complex issues surrounding the permitting of new transmission, Hoffman suggested that system upgrades could provide momentum for new projects. "If we can utilize existing rights of way, existing capacity on the system, hopefully we can accelerate some of those opportunities for getting transmission built," she said.

Bottom-line Benefits



Rob Gramlich, Grid Strategies | *© RTO Insider LLC*

Beyond upgrading lines with advanced conductors, utilities and transmission operators are also now looking at other GETs, such as dynamic line ratings (DLRs) and topology optimization, said Rob Gramlich, president of Grid Strategies.

DLRs vary the capacity of transmission lines based on multiple real-time conditions, Gramlich said. "When the wind is blowing, particularly perpendicular to the lines … or if the temperature is cold, you can deliver more megawatts over the same line without running into safety [or] reliability concerns," Gramlich said. If that wind is also turning a wind turbine, "there's great alignment with renewable energy."

DLRs can also be used to redirect power to reduce congestion and increase financial savings, he said. Topology optimization software allows utilities or grid operators to track which circuits on their systems are open or closed on any given day; for example, if maintenance is being done. Power can then be rerouted, or different circuits opened or closed, to optimize efficiency and lower costs on a system, he said.

The challenge, Gramlich said, is that GETs may not provide bottom-line benefits to grid operators at this time. To fill the gap, state and federal regulators might consider incentives and, if necessary, requirements for including them in transmission planning, he said.

FERC on Thursday opened a docket on DLRs as a first step toward possibly requiring them for interstate transmission lines. (See related story, *FERC Opens Inquiry on Dynamic Line Ratings*.)

Townley argued that the economic case for reconductoring is more straightforward. Advanced conductors can be installed quickly — in some cases without shutting down the

NARUC Winter Policy Summit

| Shutterstock

system — and without extra permitting or assessments under the National Environmental Protection Act, he said.

Putting more capacity on a line can allow more renewable energy to be interconnected on a system, reducing carbon emissions and, possibly, creating carbon credits or renewable energy credits that can be sold or traded on regional markets, he said.

A 'Bright, Shiny Object'?

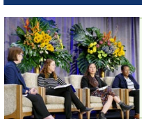
The Ray's Kelly also pointed to the streamlined permitting that is possible if new transmission is sited in existing highway rights of way. It can cut permitting times in half — from 10 years to five years, she said — which can pencil out to $1 billion in savings.

Federal policy and funding are now encouraging transmission siting in highway rights of way, she said, calling for collaboration between state transportation and energy agencies to "establish priority corridors for new construction projects. … How many of you have talked with your state" department of transportation? she asked the NARUC audience. "The answer is never or not recently. Let's start doing that today."

She also cautioned that next-gen highways should not be seen as the next "bright, shiny object" in industry discussions about transmission — a quick solution to complex problems. "The right of way, whether it's highways and interstates or the rail right of way, is an opportunity to design projects while reducing public impact," she said. "So, it's worth the effort to take the opportunity seriously."

"Let's not leave an ounce of capacity that is available online when taking a hard look at the existing system," Hoffman agreed. "Look at your rights of way; look at your ability to reconductor; partner with your environmental offices as well as your transportation offices [and] the ISOs and RTOs. Those are the partnerships that we need to think about so we can capitalize on every megawatt that's available." ■

NARUC news from our other channels



Just Transition: More than 'Checking the Box'

NetZero Insider

NARUC Panelists Call for Solidarity on Cybersecurity

ERO Insider

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

Overheard at NARUC Winter Policy Summit 2022

WASHINGTON — More than 1,000 people traveled to D.C. for the National Association of Regulatory Utility Commissioners' Winter Policy Summit last week, a hybrid affair that also offered video feeds for many sessions. Much of the talk was about the $62.5 billion in funding the Department of Energy received under the Infrastructure Investment and Jobs Act (IIJA).

Granholm: DOE Learning to Use 'New Muscles'

The infrastructure bill is not only the biggest influx of funding in DOE's history. It also marks a change in the department's role regarding new technology, Energy Secretary Jennifer Granholm told the conference Feb. 15.

"It expands our department's mandate to get clean energy technologies out into the world through demonstration and deployment. It's a new muscle for us," Granholm said, speaking to NARUC members via a video feed. "We've been really historically a research and development [agency] … with our National Labs. And now we are exercising a whole new muscle."

Although the bill's $615 million in funding for electric vehicle charging infrastructure is being awarded under Department of Transportation formula allocations, most of DOE's funding from the IIJA will be awarded competitively, Granholm said. (See *States to Get $615 Million for EV Charging from IIJA Funds*.)

"Many of these are new programs," she said. "So, we're asking folks to send us their best, most innovative ideas. We want to solicit proposals that invest in rural and underserved communities. We want to bring in smaller utilities. We want to have maximum impact for climate and job creation and justice. So we are very excited about what this law means for DOE, and obviously everyone in [the NARUC conference] room, and for the country and the planners. We just can't wait to work with you to get this done."

DOE's Energy Earthshots

Earlier thad day, the conference received a briefing on DOE's three "*Energy Earthshots*," initiatives to accelerate new technologies in order to meet President Biden's targets of complete grid decarbonization by 2035 and net-zero emissions by 2050.

Each initiative has its own cost-reduction target to achieve wide-scale deployment. The department received IIJA funding dedicated to research and development of each of the technologies: $9.5 billion for clean hydrogen; more than $10 billion for carbon capture and removal; and more than $7 billion in the supply chain for batteries.

Three DOE officials gave NARUC attendees an overview of each Earthshot, laying out just how ambitious the targets are and how necessary they will be in the future.

The goal of the *Hydrogen Shot* is to cut the cost of "green" hydrogen — produced with renewable power — to $1/kg by 2030. Because it can be used in so many different ways and in so many different sectors, producing it at scale will require unprecedented collaboration, said Kelly Speakes-Backman, of the Office of Energy Efficiency and Renewable Energy.

Energy Secretary Jennifer Granholm | *NARUC*

"Hydrogen is going to involve a greater integration of our Renewable, Fossil and Nuclear offices," Kelly Speakes-Backman said. "It's going to take an integrated approach across all sectors to realize the full benefits of hydrogen."

Michael Pesin, of the Office of Electricity, discussed the *Long Duration Storage Shot*, which aims to cut the cost of utility-scale storage that can last more than 10 hours by 90% by 2035.

He presented a graph showing the staggering amount of short-duration (up to four hours) storage that would be needed to achieve the president's 2035 target: up to 800 GW under a "high" scenario to be detailed in a future DOE report.

But the longer resources can last, the less capacity is needed. And by 2050, the U.S. will need storage that can last more than 100 hours and can be cycled seasonally or even

NARUC Winter Policy Summit

weekly, Pesin said, because of equally staggering amount of renewables that are expected to be on the grid by then.

"This is a very aggressive goal; we realize that," he said. "But we're going to [use] all the resources of the department and work with industry and all of you to make sure we can achieve this."

Finally, and perhaps most importantly, is the *Carbon Negative Shot*. Announced in November, it aims to reduce the cost of carbon dioxide removal (CDR) technologies to less than $100/net metric ton of CO_2e.

The initiative is not about point-source emissions capture, said Emily Grubert, of the Office of Fossil Energy and Carbon Management. Nor is it about carbon avoidance and mitigation practices, though all are important to achieving net-zero emissions. It's about directly removing carbon that is already in the atmosphere and oceans.

The goal is to enable gigaton-scale carbon removal. "To put this into perspective, 1 GT of CO_2 is equivalent to the annual emissions from the U.S. light-duty vehicle fleet, according to a DOE *factsheet* on the initiative. "This is equal to approximately 250 million vehicles driven in one year."

"Net zero can not happen without gigaton-scale CDR, based on a lot of the modeling we've globally and domestically," Grubert said.

The department expects to establish at least three more Earthshots in the future. Grubert noted that the Carbon Negative Shot is the "youngest" of the current three, "but hopefully not for long."

ACP Chief Cool to FERC 'Backstop' Authority

Speaking after Granholm, Heather Zichal, CEO of the American Clean Power Association, noted that most of the infrastructure funding will be spent over five to 10 years, unlike the spending in the pandemic recovery legislation, where the priority was to "get the money out the door as quickly as possible."

"So we have a little bit more time to get the projects right, and get the processes right," she said.

Zichal said she sees the infrastructure's transmission funding as helping to accomplish three goals: preventing outages from natural disasters; relieving congestion that increases consumers' costs and limits the connection of new renewable generation and deploying new technology, including offshore wind, microgrids and hybrid projects incorporating storage.

Like FERC Chairman Richard Glick, Zichal sought to lower expectations for the "backstop" authority the bill gave the commission to site transmission lines over state objections or delays. Glick told National Association of State Energy Officials conference attendees Feb. 9 that he doesn't expect many utilities to ask FERC to overrule their state regulators. (See *Glick Aiming for Final Transmission Rule by End of Year*.)

North Dakota Public Service Commissioner Julie Fedorchak asked Zichal whether FERC's exercise of that authority would result in better outcomes.

"That's quite the question," Zichal joked in response. "I might not have any friends [among state regulators] after answering it.

Heather Zichal, CEO, American Clean Power Association | © *RTO Insider LLC*

"When you have new authority, using it for the first time is scary and often a lot more difficult than you probably anticipated," Zichal said. "Most major infrastructure projects are successful when they have strong buy-in at the state, local and regional level. And so I think that's going to be ... the key to success for any of these major transmission projects. …

"Without the local and regional support, you're just not going to see those projects come to fruition," she continued. "I think there are major questions around whether and how, the new authority in the bipartisan infrastructure bill would even be utilized."

"I agree with you," responded Fedorchak. "I think the states will get it done. Right, guys? We can do this." ■

— Rich Heidorn Jr. and Michael Brooks

FERC/Federal News

Split FERC Updates Policies on Gas Infrastructure Applications

Republicans Say Uncertainty, GHG Focus Will 'Chill' Investments

By Michael Brooks

FERC voted 3-2 Thursday to update its 1999 policy statement on natural gas infrastructure certificates (*PL18-1*) and released guidance on how it will evaluate the impacts of projects' greenhouse gas emissions in its environmental analyses (*PL21-3*).

The updated policy statement concludes an effort begun in late 2017 under Chair Kevin McIntyre that languished under successor Neil Chatterjee before being restarted almost exactly a year ago by Richard Glick. (See *Glick Hits 'Refresh' at 1st FERC Open Meeting*.)

Combined with the new guidance on GHG emissions, however, it begins an era in which the commission will more closely scrutinize gas projects, including the evidence for their need and their emissions' impacts on global climate change.

Glick and his fellow Democratic commissioners, Allison Clements and Willie Phillips, said the statements would provide more certainty for pipeline developers. Glick in particular pointed to numerous projects that have been remanded or vacated by federal courts because of insufficient environmental analyses by regulators including FERC.

"In my opinion, the courts have been clear: We have an obligation under both [the National Environmental Policy Act] and the Natural Gas Act to consider the impact of reasonably foreseeable greenhouse gas emissions, and if we were to continue to turn a blind eye to climate change and greenhouse gas emissions, we would simply be adding to the legal uncertainty of these orders approving a project," Glick said during the commission's monthly open meeting Thursday.

But Republican Commissioners James Danly and Mark Christie blasted the new policies, saying that FERC was essentially rewriting the Natural Gas Act and attempting to prevent more gas pipelines from going into service.

"I happen to agree that reducing carbon emissions that impact the climate is a compelling policy goal," Christie said. "But the commission does not have an open-ended license under the U.S. Constitution or the NGA to address climate change or any other problem the majority may wish to address. ... Here's an inconvenient truth: If Congress wants to change the commission's mission under the NGA, it has that power; FERC does not."

More than Precedent Agreements Required

Among the most significant changes in the updated policy statement is that FERC will no longer solely rely on precedent agreements as evidence of need for the project.

Such agreements are private contracts between project developers and prospective customers of the project's gas. But the courts have reprimanded the commission's reliance on them as indicators of need because they are often between affiliates: developers essentially selling pipeline capacity to themselves.

"Although precedent agreements remain important evidence of need, precedent agreements alone often may not be sufficient to establish need for a project," FERC staff said in a presentation to commissioners. "The updated policy statement further encourages applicants to provide specific information detailing how the gas to be transported by a proposed project would ultimately be used, why the project is needed to serve that use and the expected utilization rate of the project."

The update also lists four major public interests that the commission will consider in determining whether a projects' benefits outweigh its adverse impacts: those of the applicant's existing customers; those of existing pipelines and their captive customers; the environment; and those of landowners and surrounding communities, including environmental justice communities.

A FERC *fact sheet* states that "the commission's consideration of landowner impacts will be based upon robust early engagement with all interested landowners and continued evaluation of input from landowners throughout any given proceeding" and that it will take into account "what a pipeline applicant already has done to acquire lands through good-faith negotiation, as well as an applicant's plans to minimize the use of eminent domain upon receiving a certificate."

Impact on Climate Change

FERC said its new policy for analyzing climate impact is considered "interim"; it asked for public comment by April 4.

Under the new policy, FERC will presume that projects with estimated GHG emissions of at least 100,000 metric tons of carbon dioxide equivalent per year will have a significant

Construction of Consumer Energy's Saginaw Trail pipeline project in Michigan | *Consumers Energy*

impact on climate change — requiring that the commission conduct an environmental impact statement — unless the developer can rebut that presumption with evidence.

The commission also stamped a policy long sought by Democrats: It will consider all "reasonably foreseeable" GHG emissions that would result from the project, including those resulting from the downstream use of the gas being transported.

Republican Dissent

Danly's and Christie's statements during the open meeting criticized both policy statements collectively. They criticized the statements as vague and ambiguous and said the majority was overstepping the commission's legal authority.

"It is very difficult for us to achieve the objectives of the Natural Gas Act, which is to encourage the orderly development of natural gas infrastructure ... when we are adopting policies that are either vague or make it difficult to rationally allocate capital," Danly said. "I think that it is inevitable that these policy statements are going to chill investments, and that they are going to do so when we have areas of the country facing ... constraints in gas supply. ...

"It is troubling to me that implicit in these two policy statements is what appears to be a displacement of congressional declaration of the importance of natural gas with the commission's seemingly implicit declaration instead that natural gas is harmful or negative and needs to be discouraged as much as possible."

The Republicans also lambasted their colleagues for implementing the interim policy immediately, despite being subject to revision, not just on new applications, but on those pending as well.

FERC/Federal News

"Changing the rules in the middle of the game violates any serious principle of due process, regulatory certainty and just basic fairness," Christie said.

Sabal Trail

Speaking to reporters by conference call after the meeting, Glick said Danly and Christie spent much of their dissents essentially disagreeing with three of the D.C. Circuit Court of Appeals' rulings, especially the 2017 *Sierra Club v. FERC* ruling on the Sabal Trail pipeline.

It was this case that sparked the ongoing dispute over the commission's analysis of gas project's GHG emissions. The issues of whether and how FERC should or even can analyze a project's downstream emissions has been debated ever since. During his time in the minority, Glick repeatedly insisted that the Republican majority was ignoring the court's directive for FERC to consider the impact of a project's emissions on climate change when evaluating it. (See *EBA Panelists Debate Role of FERC in Regulating Carbon*.)

In his dissent, Danly called the decision an "outlier," arguing that "it is very much in tension with prevailing Supreme Court precedent."

"We should not rest too much weight upon Sabal Trail," Danly wrote. "Not only is the holding narrower than the majority seems to believe and was roundly criticized by the accompanying dissent, its reasoning has since been called into question by another appellate court, and I expect it will soon be challenged in the Supreme Court."

In his statement during the meeting, Christie argued that there is no explicit court directive, noting that "since Sabal Trail, there have been more recent opinions from the U.S. Supreme Court itself reasserting its major-questions doctrine." Also known as "*the major rules doctrine*," it holds that "major questions of public policy" are reserved for Congress, not the executive or judicial branches, to answer. It came back to the fore of the court with *King v. Burwell*, which ruled on provisions of the Patient Protection and Affordable Care Act.

The doctrine is a check on *Chevron* deference, in which the courts defer to an executive agency's interpretation of a statute.

"Whether this commission can reject a certificate to build a natural gas facility, one that otherwise meets the criteria for approval under the Natural Gas Act, because of its alleged impact on global climate change, is clearly a major question of public policy," Christie said. "I cannot think of a more important question of policy — not just energy policy, but economic policy and, yes, even national security policy."

Glick countered that "it's kind of the height of arrogance, I think, to say, 'Well the court got it wrong, so I'm going to ignore the court.'" The major-questions doctrine is irrelevant, he argued, because Congress in the NGA has already directed FERC to consider whether the public benefits of a project outweigh its negative impacts.

Glick also said the prediction that the Supreme Court would overturn the D.C. Circuit is also irrelevant. The Republicans "may be right; I don't know. ... But in the meantime, we're bound" by the current ruling, he said.

Temporary Spire Certificate Remains

The commission on Thursday also responded to arguments raised on rehearing of its December order issuing a temporary certificate to Spire *STL Pipeline* to allow it to continue operating (*CP17-40-012*).

In June, the D.C. Circuit ordered FERC to vacate its decision permitting the 65-mile natural gas pipeline, saying the commission had failed to follow its own rules on evidence of a need for the facility (20-1016).

Spire announced plans for the project in 2016, but when its "open season" failed to produce any shippers wanting the capacity, it signed an agreement with one of its affiliates for 87.5% of the line's capacity. In granting the project a certificate of public convenience and necessity, FERC failed to consider "plausible evidence of self-dealing," the court said. (See *DC Circuit Slaps FERC on Pipeline GHG Analysis*.)

On Dec. 3, however, the commission granted Spire a temporary certificate, finding that an "emergency" exists because if the pipeline were to cease operations, Spire's Missouri affiliate would lose gas supply, "potentially impacting hundreds of thousands of homes and businesses during the winter heating season."

Requests by the Environmental Defense Fund and others to rehear the Dec. 3 order were automatically rejected when the commission did not act on them within 30 days.

In Thursday's order, the commission rejected the challengers' request for a stay of the temporary certificate and responded to EDF's request that it immediately address the self-dealing issue.

"While allegations of self-dealing must be taken seriously and merit additional consideration by the commission on remand of the certificate order, that issue is not relevant to the question addressed by the commission in this proceeding: whether to issue a temporary certificate in the heart of winter where the health and welfare of hundreds of thousands of customers is at stake," FERC said. ■

Rich Heidorn Jr. contributed to this report.

FERC/Federal News

FERC Opens Inquiry on Dynamic Line Ratings

Seeks Data on Costs, Benefits

By Rich Heidorn Jr.

FERC opened a Notice of Inquiry on Thursday to build an evidentiary record on the use of dynamic line ratings (DLRs), an initiative it signaled in its Dec. 16 order calling for the end of static transmission line ratings.

The December order required transmission providers to employ ambient-adjusted ratings (AARs) for short-term transmission requests for all lines that are impacted by air temperature (*RM20-16, Order 881*). But the commission did not mandate the use of DLRs, saying more evidence was needed concerning DLRs' costs and benefits. (See *FERC Orders End to Static Tx Line Ratings*.)

Thursday's NOI solicits comments on potential criteria for DLR requirements, the benefits, costs and challenges of implementing DLRs, and time frames for implementation. It also asks whether the lack of DLR requirements makes wholesale rates unjust and unreasonable (*AD22-5*). In the December order, the commission said the use of only seasonal and static ratings was unjust and unreasonable because it resulted in the underutilization of available transmission capacity.

Dynamic line ratings, such as those provided by LineVision's overhead line monitoring system, can allow increased transmission capacity and provide grid operators with real-time situational awareness of potential problems. | *LineVision*

Initial comments are due 60 days after publication in the *Federal Register*, with replies due 30 days later.

AARs vs. DLRs

While AARs are based on forecasted ambient air temperatures and the presence or absence of solar heating, DLRs also consider wind, cloud cover, solar heating intensity, precipitation and line conditions such as tension or sag.

The December order required transmission providers to use AARs as the basis for evaluating transmission service requests ending within 10 days. It also required providers to electronically update transmission line ratings at least hourly to allow for use of DLRs by transmission owners that voluntarily adopt them.

The order acknowledged that DLRs can benefit customers when the limiting element of a congested transmission facility is the conductor and conditions besides ambient air temperature impact the line's capacity. It also noted that in addition to often allowing greater power flows, DLRs can also detect situations where power flows should be reduced to maintain safety and reliability.

Costs

But the commission said it could not consider mandating DLRs without more information on their costs and challenges, such as the costs of sensors and cybersecurity.

In the Order 881 proceeding, some, including SPP's Market Monitoring Unit and industrial customers, endorsed DLRs. But, FERC noted, "many commenters, including nearly all transmission owners that filed comments about DLRs, either opposed a requirement to implement DLRs on all transmission lines or opposed a DLR requirement in any form."

FERC cited Bonneville Power Administration's estimate that DLR implementation would cost more than $1 million per transmission line in monitoring equipment, software and hardware, and MISO Transmission Owners' estimate of $100,000 to $200,000 per transmission line, or $1.5 billion for the entire RTO. SPP said DLR could require an energy management system (EMS) upgrade at a cost of up to $1 million.

Among the NOI's 29 questions were queries on:

- whether FERC should require DLR implementation on all or only certain transmission lines, and what criteria (e.g., congestion, curtailment levels, voltage levels, infrastructure, and/or geography/terrain) it should use to decide;
- whether FERC should regularly reevaluate lines to ensure its criteria still apply;
- whether there are differences between RTOs/ISOs and non-RTO/ISO transmission providers that the commission should consider;
- how DLR requirements should be considered in regional transmission planning and interconnection processes;
- what transparency measures the commission should require (e.g., informational reports that show which transmission lines meet criteria for DLR implementation);
- the potential impacts to reliability if the digital devices that monitor or communicate line conditions are hacked in a cyber event;
- whether FERC should order NERC to evaluate how a DLR requirement could introduce risks to the operation of the bulk electric system and whether any standards require modification to address risks;
- whether FERC should require the use of sensors or just more up-to-date weather forecasts than required in Order 881;
- how often transmission providers should be required to calculate transmission line ratings and for what services (e.g., hourly point-to-point; daily point-to-point; weekly point-to-point, etc.);
- whether the commission should limit the number or proportion of transmission elements on which a transmission provider must implement DLRs at any one time; and
- the appropriate time frame for identifying which lines are subject to DLRs, designing a DLR system, and integration and testing of the system. ■

FERC/Federal News

FERC-State Tx Task Force Debates Allocation, Benefits

Glick: 'Everybody Wants More Transmission; No One Wants to Pay'

By Amanda Durish Cook and Tom Kleckner

The second meeting of a federal-state task force convened to spur transmission buildout exposed differences among regulators over how FERC could expand the menu of recognized transmission benefits when allocating costs for new projects.

The stickiest topic during Wednesday's Joint Federal-State Task Force on Electric Transmission meeting in D.C. was how to divvy the costs of regional transmission projects that advance state public policy goals.

"We decided to go with the non-controversial, easy subject: transmission cost allocation," FERC Chairman Richard Glick joked as he opened the meeting. "Everyone wants more transmission; no one wants to pay for it."

A collaboration between FERC and the National Association of Regulatory Utility Commissioners, the task force could produce recommendations for new regulatory language or initiatives to improve transmission development. The team first met in November. (See *FERC-State Tx Task Force Begins Work*.)

Glick said FERC is interested in whether regions are fully assessing all the benefits associated with new transmission. Although the commission has broad authority in prescribing cost allocation, state cooperation is vital, he said.

"It would be foolish to think that we could do whatever we want and go home," Glick said, noting that states wield authority over siting. "It's vital that we go into this arm-in-arm and find something we can live with."

Maryland Public Service Commission Chair Jason Stanek, task force co-chair alongside Glick, likened the discomfort with discussing allocation to the situation when a single bill arrives for large party of diners. He said the task force is focusing on how to split more nebulous transmission benefits like societal benefits, economic gains and cleaner air.

Matthew Nelson, chair of the Massachusetts Department of Public Utilities, said he saw nothing wrong with dividing a dinner bill based on who had a "more expensive meal or had a beverage with their dinner," given that some states have more ambitious emissions-reduction and renewable energy targets.

But Glick pushed back against that idea.

FERC Chair Richard Glick (left) and Maryland PSC Chair Jason Stanek lead the task force's meeting. | *NARUC*

"It isn't just the public policy goals that are achieved when projects are built in part to satisfy those public policy goals. There are other benefits — resilience, reliability, economics and so on," he said.

The FERC chair also reminded the task force that quantifying benefits for allocation is both an "art and science." He expressed optimism that the task force can isolate benefit measurements with a degree of certainty.

Stanek shared optimism that many benefits have "a price tag associated with them" and said sharper forecasting capabilities and better modeling tools are available today. He suggested that regulators solicit NERC's input to conduct regional analyses "in order to award potential transmission projects with some quantifiable benefits."

Glick agreed with that approach. "We need to figure out ways to expand the list of benefits that we are looking at … to be more granular in terms of type of benefits we are looking at, but also in terms of being able to better assess the value of those benefits and, more importantly, who benefits."

IDing Necessary Tx Projects

The task force also pondered whether the three major drivers for building transmission — reliability, economics and public policy — should be expanded.

California Public Utilities Commissioner Clifford Rechtschaffen requested FERC issue guidance on additional types of benefits and methods for assessing them.

He suggested the reliability category should be opened to grid hardening projects; the economic category should include projects that facilitate improved connectivity to lower-cost generation and reduce market power; and the public policy category should be extended to projects that further a clean energy transition.

Rechtschaffen also argued that FERC guidance should extend the time frame for measuring benefits to 15 or 20 — or longer. "This better corresponds to longer-range goals such as renewables integration and emissions reduction targets," he said.

Glick said the traditional, siloed approach to transmission cost-sharing makes less sense going forward. He said projects earmarked for one benefit often deliver other benefits once built.

"This idea that we can just plan for and allocate costs for transmission based on one particular set of benefits is probably a little bit outdated and doesn't mix with reality," he said.

FERC Commissioner Mark Christie cautioned that defining benefits too generally risks the construction of unnecessary transmission projects and extraneous costs to ratepayers. He also said directing RTOs to plan on a 15-year horizon seems uncomfortably close to

FERC/Federal News

the states' integrated resource planning (IRP) processes.

"I would caution [that] looking at a 15-year holistic plan sounds like an IRP, and states are set up to do IRPs, and I don't know the RTOs are set up to do IRPs," Christie said. "Do you want RTOs to become integrated planners?"

In that scenario, Christie said, "money would begin to flow" on projects in an RTO's regional plan before states had a chance to weigh in. As an example, he said Indiana ratepayers should not pay for a portion of a billion-dollar transmission line that serves a Virginia renewable portfolio standard.

In recapping the meeting, Stanek noted several members had brought up the importance of grid resilience and adding that as a new category in allocating costs.

"There's a lot of benefits that are hard to quantify, but perhaps resilience is one topic where we could have some asymetrics on a regional basis, as opposed to a one-size-fits-all in terms of resilience for the country," he said.

Utah PSC Chair Thad LeVar (left) speaks to Western needs as FERC Commissioner Willie Phillips listens. | *NARUC*

Consent Role for States

Christie asked state commissioners whether they should have a role in approving grid operators' cost-allocation methodologies.

Kansas Corporation Commission Chair Andrew French recalled the praise he offered SPP during the first task force meeting.

"[SPP] offers the broadest, or one of the broadest, sets of rights to its state regulators and involves them in the cost allocation process, resource adequacy process and other items," he said. "We have primary authority for setting the basis of any regional cost allocation."

French said the RTO typically defers to decisions of the Regional State Committee (RSC), as it did last month when the RSC and the board approved fixes to FERC-identified deficiencies in the local facility cost-allocation process that had previously been contested by stakeholders. (See *SPP Board of Directors/Members Committee Briefs: Jan. 25, 2022*.)

"To the question of whether there should be a rigid consent of the states for cost allocation, that is tough," French said. "I would exercise caution in saying our region, or any region, should have to reach consent of every single state before agreeing on cost-allocation methodology. There are going to have to be a lot of discussions and negotiations between lots of different counterparties to figure out what works and, ultimately, it would be ideal to come up with a framework that you could put in place for multiple iterations of similar planning processes in the future."

North Carolina Utilities Commissioner Kimberly Duffley said that FERC should consider giving states a consent role but reminded her peers that not every state is the same.

"I think the concern for states is that they would have no control over their own destiny and their own costs," she said. "We also need to think about equity issues and energy burden issues when you're looking at this problem, because there are many states that have a much higher energy burden than other states. Asking them to take on another state's public policy goal when they're struggling to maintain the costs when reliability is the main driver is a hard pill to swallow."

French cautioned against using "lists of dozens of different benefits that transmission can provide" as justification for a plethora of projects.

"I think that we should exercise a little bit of caution [rather than] just saying, 'We are going to plan on using all of these benefits and we are going to build every single project,'" he said.

Arkansas Public Service Commission Chair Ted Thomas called for a "rigorous review" of benefits identification instead of relying on postage stamp rates.

"To make this process work, one of the things we need is common ground between those who see a policy imperative for building transmission and those who are worried about a fair deal and fuzzy benefits on the other side," he said. "How you bridge that gap, I think, starts with identifying these benefits."

FERC's Willie Phillips said that as a new commissioner he's interested in balancing energy sustainability with affordability. "Having grown up in rural Alabama, I know firsthand how any cost increase can affect customers and that affordability is a critical backbone to economic development." ■

Vermont Public Utility Commissioner Riley Allen (left) and FERC Commissioner Mark Christie | *NARUC*

FERC/Federal News

DOE Launches $6B Nuke Credit Program

$3B for Battery Supply Chains

By Rich Heidorn Jr.

The U.S. Department of Energy last week invited public comment on a $6 billion program to prevent the early closure of nuclear generators.

The Civil Nuclear Credit Program, funded under the Infrastructure Investment and Jobs Act (IIJA), will allow owners and operators of commercial nuclear reactors at risk of closure to competitively bid on credits to keep them in operation. The IIJA requires applicants to prove their reactor will close for economic reasons and that the closure will result in increased air pollution. Credits will be allocated over a four-year period.

"U.S. nuclear power plants are essential to achieving President Biden's climate goals, and DOE is committed to keeping 100% clean electricity flowing and preventing premature closures," Energy Secretary Jennifer Granholm said in a statement.

Nuclear power currently provides 52% of the nation's 100% carbon-free power, but 12 reactors have closed since 2013 because plant owners said they were unprofitable. Illinois, New Jersey, New York and Connecticut have all approved subsidies to keep nuclear plants within their borders operating.

DOE's *Request for Information* in the *Federal Register* solicits comments on subjects including the certification process, eligibility criteria and allocation of credits. The RFI was accompanied by a Notice of Intent informing generators of the program.

The department's *press release* announcing the program quotes an endorsement from Sen. Joe Manchin (D-W.Va.), chairman of the Senate Energy and Natural Resources Committee and an essential vote for the climate programs in the Biden administration's proposed Build Back Better bill.

"I fought for the inclusion of this critical program to prevent further premature closures of nuclear power plants and to maintain high-paying jobs in communities across America," Manchin said.

Responses to the NOI and RFI addressing general program design and bid process are due by 5 p.m. MT on March 17. Responses on the certification process should be submitted by March 8.

Battery Supply Chains

DOE on Feb. 11 also *outlined* a $2.91 billion program in the infrastructure law funding refining and production plants for battery materials, battery cell and pack manufacturing, and recycling.

Responding to Biden's *executive order* on supply chains, DOE last year recommended establishing domestic production and processing capabilities for critical materials for a domestic battery supply chain.

PSEG has said it needs additional revenues to receive production tax credits for its Hope Creek and Salem nuclear plants. | *Public Service Enterprise Group*

One *NOI* details DOE plans to support the creation of new, retrofitted and expanded domestic facilities for battery recycling and the production of battery materials and cell components.

A second *NOI* outlines DOE's initiative for research, development and demonstration of second-life applications for batteries previously used in electric vehicles. It seeks proposals for new processes for recycling, reclaiming and adding materials back into the battery supply chain. ■

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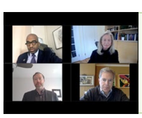

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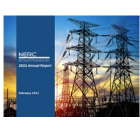

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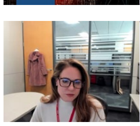

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CAISO/West News

NWPP Rebrands as Western Power Pool

By Robert Mullin

In a move that signifies its expanding reach across the Western Interconnection, the Northwest Power Pool has rebranded itself as the Western Power Pool.

What was once a member-run organization focused mainly on grid reliability in the Pacific Northwest and Intermountain regions, Portland, Ore.-based NWPP (now WPP) has spent the past two years going south — and east.

Since 2020, WPP has been developing the Western Resource Adequacy Program (WRAP), an initiative conceived to address concerns that Northwest utilities have been increasingly — and unknowingly — drawing on the same shrinking pool of reliability resources. Participants used its "matching service" for entities either long or short in the electricity market four times that year, mostly during a record-smashing heat wave in the Pacific Northwest.

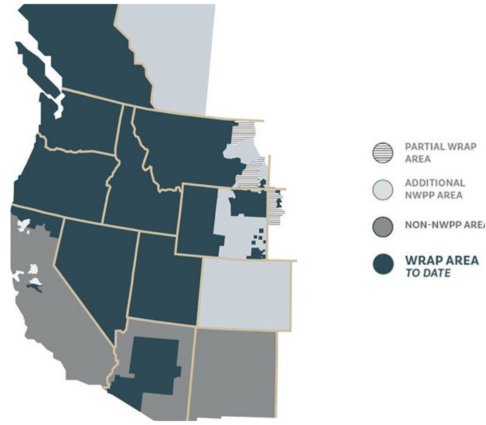
But interest in the effort spread quickly to other areas of the West. The WRAP, which is slated to launch a "nonbinding" iteration in the third quarter of this year, has attracted participants from an area spanning British Columbia, south to Arizona and east into South Dakota. Stage 1 of the WRAP will include 26 participants that together represent a summer peak load of about 67,000 MW and a winter peak of more than 65,000 MW.

"With the addition of new participants from the Southwest and the expansive footprint of our existing programs, we are excited to announce a name change that demonstrates our vision," WPP COO Gregg Carrington said in a statement Feb. 8. "The Western Power Pool will continue to offer the excellent services our customers rely on while creating a more inclusive space for Western coordination and collaboration."

In creating the WRAP, WPP has also been forced to repurpose itself as an organization. Once the WRAP enters its "binding" phase in 2023, the market — and WPP — will become subject to federal oversight and FERC rules.

Anticipating those requirements, WPP has already moved to restructure its governance and prepare to adopt some elements of an RTO, such as the appointment of an independent board of directors. WPP will also establish an RA Participants Committee as well as a Committee of States to ensure that utility regulators have a voice in discussions related to the WRAP. (See *RA Program will Require Restructuring of NWPP*.)

And while WPP has not signaled intentions to expand the WRAP's offerings beyond resource adequacy, the market looks increasingly like a possible platform for incrementally developing a Western RTO — one that would compete with CAISO's stalled regionalization efforts, the ISO's well established Western Energy Imbalance Market, and SPP's nascent RTO West and Western Energy Imbalance Service.



The NWPP has changed its name to the Western Power Pool in part to reflect the expansion of the WRAP's footprint. | *NWPP*

WPP last year selected SPP to operate the technical aspects of the WRAP, providing the market's forward-showing functions, modeling and system analytics, and real-time operations.

In December, SPP revealed plans for broader engagement with WRAP participants through its *Markets+* program, a "conceptual bundle of services" that includes day-ahead and real-time commitment and dispatch, and "hurdle-free" transmission service. Those services would be packaged in a way designed to appeal to utilities still unready to commit to a full RTO, SPP said. (See *SPP Aspires to Increase its Western Footprint in 2022*.) ■

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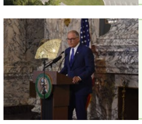

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Rate Hikes Prompt Concern in California

PG&E Residential Electric Bills Rise 19% from January to March

By Hudson Sangree

The California Public Utilities Commission is questioning how much more ratepayers can stomach after approving back-to-back $1 billion rate increases for Pacific Gas and Electric and substantial rate hikes for the state's two other large investor-owned utilities.

The increases were mostly driven by high natural gas prices and FERC transmission-rate requirements, among other factors, commissioners said.

"We've seen significant rate increases in each of the three major investor-owned utility service areas in the last few months," Commissioner Darcie Houck said Feb. 10 before "reluctantly" approving the second major rate hike to hit PG&E customers since January. "Ratepayers have justifiably voiced concerns and objections to these rate increases."

"We as a commission must carefully consider what and whether ratepayers can withstand regarding further rate increases, and we need to explore innovative methods to help curb rate increases and to protect the most vulnerable Californians," Houck said.

The CPUC has scheduled an en banc *hearing* on utility rates for Feb. 28 and March 1 intended to examine proposals to control costs and mitigate rates. The two-day session follows a similar hearing last year attended by CAISO governors, state energy commissioners and legislative leaders, all concerned with spiraling costs. (See *Calif. Worries High Rates Could Hurt Climate Efforts*.)

The increases that took effect in January and others that start in March will worsen the situation, CPUC commissioners said.

In PG&E's case, the CPUC *approved* a $769 million increase to the utility's Energy Resource Recovery Account (ERRA) and a $358 million addition for ERRA under-collection in 2021, adding more than $1.1 billion to PG&E's 2022 revenue requirement.

It will result in a nearly 11% rate hike for residential customers, averaging $16.37 per month, and larger increases for commercial and industrial users.

The changes, approved Feb. 10, take effect March 1.

"An industry and worldwide increase in natural gas commodity prices in 2021 and into 2022 has increased costs and is a main contributor to the increase approved today, which allows PG&E to recover from ratepayers the costs PG&E incurred to purchase power for customers in 2021 and forecasted costs for power in 2022," the CPUC said in a statement following the decision.

The CPUC said it could re-examine the decision later this year if gas prices fall.

The new increase came on top of an 8% rate hike that took effect Jan. 1, averaging $11.29/month for PG&E residential customers.

The main drivers were a $671 million increase in FERC-approved transmission rates and a $284 million increase in PG&E's general rate case for program costs, the CPUC said. The commission also granted PG&E $173 million in additional revenue to cover losses from unpaid bills during the pandemic and additional funds for wildfire insurance premiums.

"Ratepayers in PG&E territory have had a particularly difficult year and are questioning these increases along with safety concerns, given the many catastrophic wildfires suffered over the years," ignited by PG&E equipment, Houck said.

"In addition to energy fuel costs rising, we are also facing challenges to grid infrastructure upgrades and ensuring sufficient resources to meet our clean energy goals," she said. "All of these items require investment. All this said, ratepayers are not an unlimited source of funds to cover any and all costs."

SCE, SDG&E

For Southern California Edison, the CPUC approved a January rate increase of 2.9%, working out to an average monthly bump of $3.99 in residential bills.

The causes included the addition of $385 million to SCE's general rate case for wildfire mitigation work, including vegetation management, installing covered conductor, and upgrades to SCE's transmission and distribution grid. The CPUC also authorized an increase of $238 million for transmission capital, operation and maintenance costs in 2022, based on prior approval from FERC.

SCE's purchase of $1 billion in liability insurance, as required by state law, contributed to the rate hike, the CPUC said.

CPUC headquarters in San Francisco | *© RTO Insider LLC*

CPUC-approved increases that take effect in March reflect high natural gas prices, the recovery of $401 million in wildfire prevention costs and $77 million for unpaid bills during the pandemic.

In December, the CPUC approved $1.2 billion in rate recovery for SCE's procurement of 536 MW of energy storage for summer reliability. About $85 million of that will be collected in 2022, the CPUC said.

Starting in March, SCE residential customers can expect an additional 7.7% bill increase, adding $11.48 a month on average.

Between the January and March rate hikes, SCE residential customers will be paying nearly 11% more for electricity this year, or about an extra $12.50 per month.

San Diego Gas and Electric residential bills rose by 11.4% in January because of a $273.5 million boost to the utility's revenue requirement, mostly based on high gas prices, and $38.5 million for transmission costs authorized by FERC, the CPUC said. Insurance premiums of $65 million also contributed to the higher rates.

CPUC President Alice Reynolds and commissioners Genevieve Shiroma and Clifford Rechtschaffen also expressed concern about rising electricity costs.

Rechtschaffen said the CPUC must continue working on the issue, including at the upcoming en banc hearing.

"We're looking for innovative ideas to improve affordability, especially for low- and moderate-income customers," Rechtschaffen said. "We really need to dig deeply into some of these solutions." ■

CAISO/West News

SoCalGas Proposes Hydrogen Pipelines

Los Angeles Becoming Center of Green Hydrogen Efforts

By Hudson Sangree

SoCalGas said its Angeles Link project could reduce dependence on the Aliso Canyon underground natural gas storage facility, site of an immense methane link in 2015. | *Blade Energy Partners/CPUC*

Southern California Gas proposed plans Thursday for what could be the largest green hydrogen infrastructure in the nation, with pipelines moving hydrogen from solar farms in the Mojave Desert and other inland areas to customers in the Los Angeles Basin.

The preliminary *plan* submitted to the California Public Utilities Commission proposes "one or more trunk transmission pipelines that would run from green hydrogen generation sources," where renewable resources would be used to manufacture hydrogen, an energy-intensive process.

"The project would benefit ratepayers and the state by advancing California's net zero goals, increasing use of clean fuels" and help to "facilitate the ultimate closure of [SoCalGas'] Aliso Canyon underground gas storage facility," site of a massive natural gas leak in 2015, the utility's application to the CPUC said.

SoCalGas asked the commission only for a memorandum account to keep track of expenses, for possible cost recovery later, as it pursues early-stage research and development. It requested that the CPUC approve the account by July. But it said the proposal was significant enough, "given the innovation and broad environmental benefits … [that] SoCalGas believes it important to provide the commission and the public with information about the project and its context in this first filing."

"In one or more subsequent filings, SoCalGas expects to seek commission approval of the project and recovery of just and reasonable costs incurred," it said.

SoCalGas is the largest gas utility in the U.S., with 5.8 million customer accounts and more than $3.6 billion in sales in 2020, according to the American Gas Association.

Hydrogen Hub

The application added to the focus on Los Angeles as a center of green hydrogen development.

The Los Angeles Department of Water and Power (LADWP) is converting its coal-fired Intermountain Power Plant in Utah to an 840-MW combined cycle natural gas-fired facility. The plant will be capable of burning a fuel mixture consisting of 30% hydrogen when it opens in 2025, transitioning to 100% by 2045, the utility has said.

A *report* published last March by the National Renewable Energy Laboratory — titled "LA100: The Los Angeles 100% Renewable Energy Study" — showed that LADWP will require a large amount of dispatchable generation closer to home to reach a 100% clean-energy goal and replace four outmoded natural gas plants that need to be rebuilt or retired.

The Los Angeles City Council *voted* in September to require that 100% of the electricity used in the city be carbon-free by 2035, establishing a 2030 deadline for replacing the gas-fired plants.

And the Green Hydrogen Coalition has been leading development of a green hydrogen hub in Southern California. The goal of the HyDeal Los Angeles initiative is to deliver green hydrogen for the Los Angeles Basin at $1.50/kg by 2030.

In a probable boost to that effort, the $1.2 trillion infrastructure bill passed by Congress in November provides $8 billion for development of four green hydrogen hubs in the U.S. and $1 billion toward domestic production of the electrolyzers needed to produce hydrogen, part of the Department of Energy's Hydrogen Energy Earthshot initiative. (See *'Ecosystems' Needed to Drive Green Hydrogen Growth*.)

SoCalGas said its new plan, called "Angeles Link," could provide the green hydrogen needed to convert the four outdated gas plants to cleaner generation and displace up to 3 million gallons of diesel fuel per day, if heavy-duty diesel trucks are replaced by hydrogen fuel-cell trucks.

"As contemplated, the Angeles Link would deliver green hydrogen in an amount equivalent to almost 25 percent of the natural gas SoCalGas delivers today," the utility said in a *news release*.

LADWP praised the effort.

"We are encouraged that SoCalGas is embarking on a major project that will help make green hydrogen a reality here in Los Angeles," LADWP General Manager Marty Adams said in the SoCalGas statement. "Developing a source of safe, affordable green hydrogen is key to achieving our clean energy future by 2035, while ensuring the reliability we all need and depend on."

Spotty Record

California is legally mandated to replace all fossil-fuel generation serving retail customers with clean-energy resources by 2045 and to reduce greenhouse gas emissions 40% below 1990 levels by 2030. How a partial replacement of natural gas with green hydrogen might play out under the mandates is untested and could prove problematic.

SoCalGas said in its application that green hydrogen could help decarbonize "'hard-to-electrify industries,' electric generation and the heavy-duty transportation sector" while advancing "progress toward net zero goals."

The CPUC has yet to take any action regarding SoCalGas' application.

The utility has wrangled with its regulator in recent years, being punished for misdeeds — including a nearly $10 million fine earlier this month — that the pipeline announcement appears geared to partly offset in the public eye.

SoCalGas' past run-ins with the CPUC include the long-running *Aliso Canyon* controversy, which resulted in a CPUC investigation and continued oversight. It also generated last year's $1.8 billion legal settlement between plaintiffs, SoCal Gas and parent company Sempra Energy.

In April 2019, the CPUC fined SoCalGas $8 million for failing to send out prorated customer bills in a timely manner, resulting in higher bills and extending the billing period for many customers.

On Feb. 3, the CPUC fined SoCalGas $9.8 million for misspending ratepayer funds for advocacy work on building codes. The commission had prohibited such activities in 2018 after its Public Advocates Office determined SoCalGas inappropriately used ratepayer money to fight energy-efficient building standards.

In its proposed *decision*, the CPUC said SoCalGas had shown "profound, brazen disrespect for the commission's authority" during the investigation and deserved to be penalized.

The company said in a brief statement it was reviewing the decision and looked forward to "further engagement." It has 30 days from the issuance date to challenge the ruling, after which the proposed decision becomes final. ■

ISO-NE News

New England's Duck Curve Days Chart Solar Growth

By Sam Mintz

On two mild, sunny days in New England earlier this month, energy demand was at its lowest in the middle of the day, when the thousands of megawatts of mostly behind-the-meter solar installations in the region were at their most effective.

It's the latest example of the phenomenon first noticed in California and known as the "duck curve," named after the duck-shaped pattern that occurs from charting power demand and the availability of solar.

Increasingly common "duck sightings" in New England are a signifier of the growth of solar in the region that doesn't show any signs of slowing down.

On Feb. 11, load dipped to 11,207 MW at 12:55 p.m., according to ISO-NE. LMPs were negative for some of the mid-day period, hitting a low of $-63.83. Two days earlier, load had hit a low for the day of 11,890 MW at 12:30 p.m.

New England has seen more of these mid-day minimum load days each year since 2018, when it first occurred, according to ISO-NE data. 2019 saw three such days, with 13 in 2020 and 18 in 2021. This year has seen three so far, marking the first time the phenomenon has occurred so early.

The duck curve and solar's intermittent nature have been known to bring *operational challenges* to other regions. Grid operators have to quickly ramp up dispatchable resources when the sun goes down and solar output falls, and they might have to curtail solar generation in the case of excess capacity. ISO-NE launched an enhanced real-time fast-start pricing feature in 2017 to try to incentivize resources that can quickly ramp up their output to help address the sharp rise in demand when the sun sets.

ISO-NE spokesperson Ellen Foley said in an email to *RTO Insider* that the existence of duck curves is notable, but it "doesn't really define how the system is operated." The grid operator optimizes commitment and dispatch using the day-ahead market; it then develops an operating plan and manages the power system based on that plan, she said.

Solar Boom

Because of the distributed nature and less predictable qualities of solar, it's tricky to forecast on a day-to-day basis.

"Forecasting that [load] reduction continues to be a challenge for the ISO; going into the day, we could be forecasting high production from solar PV, only to see more cloud cover or snow lingering longer than expected, which results in the ISO using more traditional generators to replace that energy. Therefore, we are continuously working on updating and improving our PV forecasts," Foley said.

But its long-term projections, based on historical trends and state policy, show that solar production will continue to be an increasingly significant presence in New England over the next decade.

ISO-NE's latest draft forecast of solar development, *published Feb. 14*, estimates 11,298 MW of solar generation in the region by the end of 2031, nearly 2.5 times the 4,767 MW installed in New England at the end of 2021.

The RTO's changing forecast itself is another sign of the rapid solar ramp-up, with this year's projections for 2030 more than 830 MW above the 2021 forecast.

Massachusetts remains the driver of solar growth in the region, with more than two-thirds of New England's installed capacity in the Bay State. ■

A solar installation on a house in Dennis, Mass. | *DOE*

ISO-NE News

ISO-NE Asks Court for an Out as Killingly Uncertainty Balloons

By Sam Mintz

| *Shutterstock*

ISO-NE on Friday asked the D.C. Circuit Court of Appeals to undo its stay order that is keeping the Killingly Energy Center's capacity supply obligation alive and holding up the results of the Forward Capacity Auction held earlier this month.

Warning of increasing damage to New England's capacity market and its participants, ISO-NE argued that because Killingly developer NTE Energy has now defaulted on its financial assurance, the stay ordering the RTO to wait on a rehearing resolution from FERC is moot because the under-development gas plant will lose its CSO regardless of the outcome.

"The harm to the market and market participants of the delayed auction results grows with each day it continues, and the delay soon will disrupt activities necessary to the timely and orderly conduct of next year's auction. The ISO therefore respectfully submits that action by the court on this motion by Feb. 25, 2022, is justified and necessary," ISO-NE wrote in a *filing* to the court.

The grid operator has said that at the current pace, it may not be able to deliver results of the auction until mid-March, and that next year's auction may also have to be delayed by a month. (See related story, *Killingly Uncertainty Could Delay Capacity Auction Results Another Month*.)

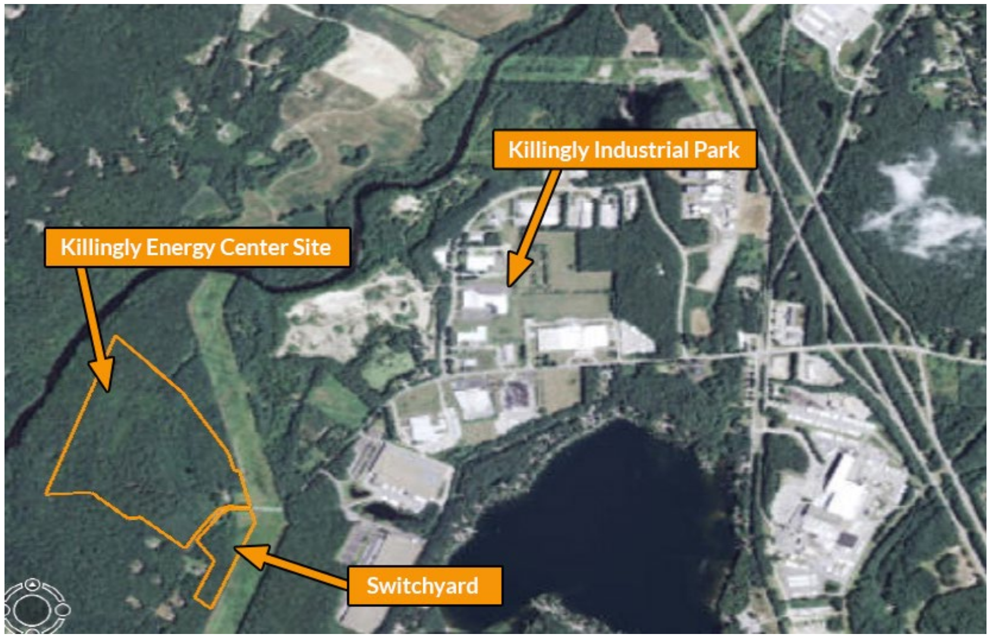
NTE was using a letter of credit for its required financial assurance with ISO-NE that will expire at the end of this month, and therefore was considered to have zero value 30 days prior (Jan. 31), according to the RTO's rules. The company failed to extend the letter of credit or provide another form of financial assurance to resolve its default and is now no longer in compliance with the financial assurance rules.

"Termination of Killingly's capacity supply obligations by operation of the tariff moots the court's stay order. With or without the stay order, Killingly's capacity supply obligations are terminated. Therefore, the ISO requests that the court dissolve its stay order because the stay no longer serves any purpose," ISO-NE said. ■

ISO-NE News

Killingly Uncertainty Could Delay Capacity Auction Results Another Month

By Sam Mintz



Killingly Energy Center is the cause of significant uncertainty in ISO New England's capacity market. | *NTE Energy*

It could be another month before stakeholders and the public in New England find out the results of ISO-NE's capacity auction from last week as the grid operator wrestles with the ongoing fallout of an 11th-hour court ruling over a Connecticut power plant.

In a *filing* to FERC on Feb. 15, ISO-NE said that the Feb. 4 D.C. Circuit Court of Appeals ruling allowing the Killingly Energy Center to temporarily maintain its place in Forward Capacity Auction 16, which took place on Feb. 14, could mean it is unable to announce the results of the auction until mid-March or later.

As of right now, there are two sets of auction results hanging in limbo, as ISO-NE calculated clearing prices and quantities both with and without Killingly participating.

That means the grid operator will also have to delay its preparations for next year's capacity auction, FCA 17, which were supposed to begin last week. For example, ISO-NE was required to provide market participants that have existing capacity resources with their qualified capacity values for those resources on Thursday.

"The definitive calculation of those qualified capacity values cannot be made for all resources without final FCA 16 results," ISO-NE said in the filing.

The grid operator considered moving forward with planning for next year's auction using both sets of results but decided that approach would not be compatible with its systems and processes and would pose "extraordinary risk to all the downstream activities."

ISO-NE is asking FERC for permission to delay establishing that and other dates as part of the FCA 17 timeline until the Killingly situation is clarified.

FERC still has an important role to play in ending the uncertainty. The agency has a rehearing request in front of it, filed by Killingly developer NTE Energy, which is appealing the agency's decision to affirm an ISO-NE decision to terminate the capacity supply obligation for the project. (See *Killingly Stays Alive After DC Circuit Halts FERC's Termination Order*.)

While FERC issued a notice denying rehearing "by operation of law" on Feb. 11, that was not sufficient to "resolve" the request, ISO-NE said.

The uncertainty could also mean that next year's capacity auction is pushed back to March instead of February.

"Based on the analysis that the ISO has conducted to date, the ISO envisions that the qualification activities for FCA 17 will begin in April 2022, and FCA 17 will occur in March 2023," the filing said. ■

MISO News

MISO, SPP Take on 2nd Interregional Planning Effort

TMEP Announcement Comes after $1.76 billion JTIQ Portfolio Reveal

By Amanda Durish Cook

MISO and SPP will begin a smaller interregional planning study this year along with their ongoing joint interconnection queue study, stakeholders learned last week.

The study will come in the form of a targeted market efficiency project (TMEP) approach instead of the usual coordinated system plan (CSP), the RTOs announced during an Interregional Planning Stakeholder Advisory Committee meeting Feb. 15. TMEPs are smaller, congestion-relieving cross-border transmission projects already in use between MISO and PJM.

The grid operators last performed a CSP in 2020. Their joint operating agreement requires an interregional study no less than once every two years.

MISO and SPP have undertaken four CSP studies since 2014. Each time, their planners have come up empty in agreeing on beneficial projects despite increasing congestion at their seams. (See *4th Time No Charm for MISO-SPP Interregional Study*.)

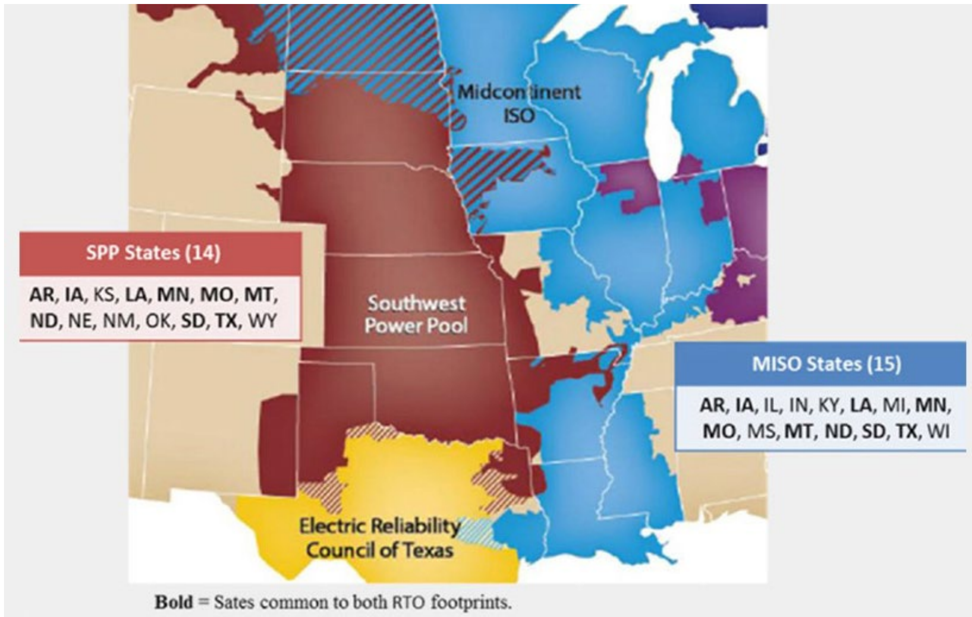
This year, however, the RTOs will juggle the TMEP study alongside the Joint Targeted Interconnection Queue (JTIQ) study, which last month rolled out a $1.755 billion portfolio of suggested projects. (See *MISO, SPP Roll out $1.755B Joint Tx Portfolio*.)

The JTIQ is meant to increase system capacity and ease the grid operators' overcrowded interconnection queues amid shifting resource mixes. It was announced in 2020, around the time that the fourth CSP failed to produce an interregional project.

Missouri Public Service Commission economist Adam McKinnie said his commission appreciated the JTIQ study's work but pointed out several congested areas remain along the MISO-SPP seam that could use more precise upgrades.

McKinnie and other state regulators have advocated for the smaller-scale TMEP study process for more than a year. (See *MISO, SPP Regulators Call for Pancaking Fix, Smaller Projects*.)

Evergy's Katy Onnen asked that the interregional study modeling contain high wind generation scenarios, something the RTOs' modeling doesn't currently consider.



The MISO-SPP seam | *Organization of MISO States*

SPP's Neil Robertson reminded stakeholders that the proposed JTIQ portfolio will likely resolve the need for some projects that might otherwise be pursued under a TMEP process.

"I want to remind everyone that we have multiple efforts working in parallel right now," he said. "With multiple parallel efforts in the interregional planning sphere in play, there's going to be some overlap."

Robertson said MISO and SPP have yet to decide how they will model the JTIQ projects in the TMEP process.

"I just really hope you don't consider the JTIQ a done deal," McKinnie said, noting that its cost-allocation discussions are not very far along and imply that disagreements might derail projects.

"I'm fine with solutions competing against each other," he said. "I just urge you to look at issues rather than say, 'It's in the JTIQ, therefore it's a third rail that we can't touch.'"

Robertson said staffs will not consider JTIQ projects as certainties to include in a base-case model for another interregional study.

Some stakeholders said MISO and SPP might want to pursue smaller TMEP fixes while waiting on big-ticket JTIQ projects' construction.

The RTOs said they opted for a TMEP study over a CSP partly because neither is performing an economic study as part of their 2022 transmission planning. TMEPs don't require staffs to conduct production cost modeling.

"We don't have that synergy this year," MISO engineer Ben Stearney explained.

Stearney said the grid operators have a framework "starting point, given the existence of the MISO-PJM TMEP." He said the RTOs and their stakeholders will settle on a TMEP study scope and criteria throughout 2022. The process will be memorialized in their joint operating agreement.

PJM's and MISO's version of TMEPs must cost less than $20 million, be in service within three years of approval and, within four years of operation, provide congestion relief equal to or greater than the construction cost. MISO's and SPP's TMEP criteria could look different.

The grid operators also said the TMEPs' targeted study style and smaller transmission projects will help ease their interregional workload, given the ongoing JTIQ. The study is not considered part of either a CSP or TMEP study.

"The reality is that developing the cost allocations around the JTIQ are going to be complex, and we don't see that happening until 2023," Stearney said.

MISO and SPP plan to schedule more joint planning meetings in the second quarter. ■

FERC Reverses Itself on NYISO BSM Exemptions

By Michael Kuser

FERC on Thursday voted 4-1 to accept revisions to NYISO's buyer-side market power mitigation (BSM) measures designed to prioritize evaluating New York state-subsidized resources, reversing its decision in September 2020 to reject the ISO's proposal (*ER20-1718-002*).

The BSM measures are designed to prevent uneconomic resources from entering NYISO's capacity market. Under Part A of the mitigation exemption test, the ISO exempts a new entrant from the offer floor if the forecast of capacity prices in the first year of a new entrant's operation is higher than the default offer floor. Its proposed revisions, submitted to FERC in April 2020, would to place "public policy" resources (i.e., renewable resources, battery storage and other zero-emission resources) ahead of non-public policy resources in its evaluations.

NYISO argued that in light of New York state legislation, including enactment of the Climate Leadership and Community Protection Act (CLCPA), subsidized resources were more likely to be completed. Unlike in 2020, under a Republican majority, the commission this time agreed.

"We are persuaded by evidence in the record indicating that NYISO's proposed resequencing of resources is just and reasonable because it will minimize artificial capacity surpluses, which, as NYISO's Market Monitoring Unit [Potomac Economics] explains, would otherwise occur 'because the current Part A test can provide inefficient incentives for investment in new resources that are not needed,'" the commission said.

In addition to the CLCPA's binding targets, the commission said that the Accelerated Renewable Energy Growth and Community Benefit Act provides for fast-track environmental review and permitting for major renewable energy facilities, and a number of nonpublic policy resources are expected to exit the market as a result of the state's new "peaker rule" limiting NO_x emissions.

FERC directed the ISO to submit a compliance filing within 30 days proposing a new effective date for the revisions no later than Aug. 1, the start of the next class year.

Reversal

FERC had approved several other of NYISO's proposed revisions to the BSM measures in September 2020, including a formula that limited the amount of renewables that could be exempted. But its rejection of the Part A changes prompted a dissent from then-Commissioner Richard Glick and rehearing requests by the ISO, Equinor, New York Transmission Owners, the New York State Energy Research and Development Authority and the New York Public Service Commission. (See *FERC Rejects NYISO Bid to Aid Public Policy Resources*.)

The Republican majority at the time said NYISO's plan was "unduly discriminatory because it does not provide sufficient justification for prioritizing the evaluation of public policy resources before nonpublic policy resources, independent of cost."

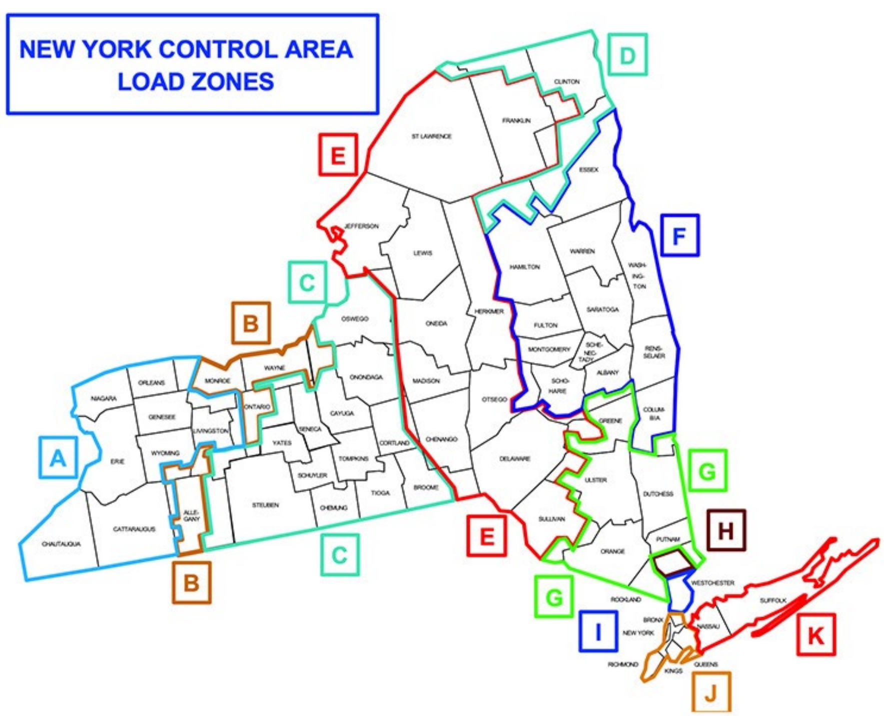
Commissioner James Danly, now in the minority, said in a dissent that "the justifications offered in this order are simply unconvincing."

"Our duty is to ensure just and reasonable rates pursuant to the [Federal Power Act], and not to determine whether NYISO's proposal is consistent with federal, state, or municipal renewable energy policies," Danly said.

Fellow Republican Commissioner Mark Christie concurred in a separate statement, taking exception to the majority's reasoning.

"New York's state law is discriminatory in its expressed preference for certain types of resources," Christie said, while noting that the FPA does not pre-empt the state from doing so. "Does this make the NYISO's tariff revisions — through which NYISO is acting necessarily to *accommodate* the reality of New York's laws — produce rates that are 'unjust, unreasonable and/or unduly discriminatory' under the FPA? Under an 'as-applied' analysis of this specific, single-state ISO filing by NYISO — and under a practical approach — I do not find it so."

Christie also said that there is no evidence that NYISO's proposal would harm consumers in other states, and "if the people and businesses of New York do not like the impacts of their new state laws, their recourse is to the ballot box," Christie said. ■



The ISO's BSM rules require new ICAP resources in New York City and zones G-I to offer at or above the default offer floor. | *NYISO*

NYISO Business Issues Committee Briefs

Updates External ICAP Rights

The NYISO Business Issues Committee on Wednesday approved *revisions* to the Installed Capacity (ICAP) Manual that update capacity import limits for the 2022/23 capability year.

The ISO completed deliverability testing and determined that all of the import rights are deliverable, said Pallavi Jain, senior ICAP market operations engineer. The update is part of an annual process to determine the maximum amount of import capacity allowed from neighboring control areas.

NYISO performed simulations to determine capacity imports allowed without violating the loss-of-load expectation (LOLE), one day in 10 years. The ties excluded were interface facilities with unforced capacity deliverability rights; controllable lines from PJM into the New York Control Area; and the NUSCO 1385 Northport-Norwalk Harbor Cable between Long Island and Connecticut.

	2022-2023 Capability Year					2021-2022 Capability Year				
Four-Control-Area-Participation	PJM	ISO-NE	Quebec	Ontario	Totals	PJM	ISO-NE	Quebec	Ontario	Totals
Initial Values (TTC Summer Ratings)	1450	1400	1690	1850	6390	1450	1400	1690	1850	6390
Grandfathered Rights*	1080	0	1110	0	2190	1080	0	1110	0	2190
Individual Limits (above GF)	218	401	17	77	713	285	459	18	80	842
Individual Limits (above GF) Delta	-67	-58	-1	-3	-129					
Simultaneous Limits (above GF)	66	122	5	23	216	149	241	9	42	441
Simultaneous Limits (above GF)Delta	-83	-119	-4	-19	-225					
Final Values **	1146	122	1115	23	2406	1229	241	1119	42	2631
*Final Values** Delta*	-83	-119	-4	-19	-225					

*Includes ETCNL for these purposes
**2022/2023 Capability Year Subject to Deliverability Study

External ICAP Rights for the 2022/2023 Capability Year, confirmed by deliverability testing, compared to the previous year's figures | *NYISO*

Concerns on Response to FERC

One stakeholder brought up the issue of NYISO responding to FERC's Feb. 9 *deficiency* letter regarding the ISO's January *filing* on its comprehensive mitigation review and capacity accreditation methodology (ER22-772).

Among other issues, FERC asked the ISO to define "marginal reliability contribution" and to "explain in detail how NYISO would calculate the marginal reliability contribution of a capacity accreditation resource class using a 'system [effective load-carrying capability] methodology.'"

"If the NYISO is responsive to FERC's questions, it will necessarily be prejudging a number of the issues that we were all to have collectively discussed over the next few months, and that is a concern to us," said Aaron Breidenbaugh of Centrica Business Solutions.

"As you know, we were not supportive of joining the two issues [buyer-side mitigation and capacity accreditation] at FERC, nor are we supportive of the marginal accreditation approach," Breidenbaugh said. "We think there's a lot of questions that remain to be answered, and obviously there's a difference of opinion on that given what was filed at FERC."

If the ISO feels pressured to answer FERC before stakeholders can discuss the issues, "it seems like in doing so they're likely to run afoul of the commitments made to the market participants that those issues be resolved in the stakeholder process," he said.

NYISO is still very focused on working with stakeholders on the many questions regarding the techniques used for calculating capacity accreditation factors, said Michael DeSocio, director of market design.

"We're going to continue full speed ahead working with you all on these issues making sure everyone understands how the calculations will work and understands the details that go into these calculations," DeSocio said. "That conversation will actually start next week, and we'll continue to move the ball forward on that as quickly as we can." ■

— Michael Kuser

Northeast news from our other channels

Vt. Maps Fast-charger Buildout for Federal NEVI Funds

Report: Challenges Ahead in Maine Power-to-Fuel Pilot Search

Advocates Seek Pathway for Biofuels in New Conn. Energy Strategy

Mass. Legislators Call for Fossil Fuel Ban in Net-zero Building Code

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

NYISO News

NYPSC Applauds Central Hudson Storm Response

By Michael Kuser

The New York Public Service Commission on Thursday lauded Central Hudson Gas and Electric and assisting utilities for their quick response to the early February blizzard that swept through its service area and cut power to more than 65,000 customers.

The Feb. 3-5 storm dumped up to 18 inches of snow across parts of the state, while freezing rain and cold temperatures lingered mainly in Ulster Duchess and Columbia counties in the mid-Hudson region, with reports of localized icing of one-half to three-quarters of an inch.

"This was the largest workforce Central Hudson has ever assembled in the over 100-year history of their company," said Kevin Wisely, director of the state's Office of Resilience and Emergency Preparedness. "The large contingent of workers moving into a concentrated area such as this does pose logistical and significant coordination challenges, particularly with housing and feeding the crews."

Central Hudson was able to house the emergency crews and has contingency plans in place, if a future need arises, to house additional workers at local universities and colleges, as well as the ability to set up large-scale tented housing units to support an incoming workforce, Wisely said.

National Grid, New York State Electric and Gas, and the Orange and Rockland utilities all provided mutual assistance to Central Hudson.

"Kudos to the utilities for working so well together, but also frankly it was really nice to see that we didn't have the administration calling for an investigation while the storm was still happening," Commissioner Diane Burman said.

The winter storm once again highlighted the need for utilities to continually reassess infrastructure vulnerabilities across their service territories to determine appropriate storm-hardening and resiliency projects to mitigate potential weather risks and adapt infrastructure to weather extremes, Wisely said.

OKs Enviro Certificate for Tx Line to NYC

The commission on its consent agenda approved a certificate of environmental compatibility and public need for the 1,250-MW Champlain Hudson Power Express (CHPE) developed by Transmission Developers Inc. and Hydro-Québec, as well as a petition for flexible financing practices (*10-T-0139* and *20-E-0598*).

The PSC will soon rule on a state *petition* to buy power from two new transmission lines being built to bring more than 2.5 GW of renewable energy into New York City, including the CHPE and the entirely in-state Clean Path NY project (*15-E-0302*).

Burman cast the lone "no" votes on both measures, saying that the commission should be looking at the transmission projects "more holistically" and that the requested flexibility in the financing arrangements is too lax.

"It's requesting flexibility to modify without prior commission approval the identity of the financing entities, payment terms and the amount financed," Burman said. "I think we should be putting in some conditions or having them come back to us if they are going to be changing some of that. I understand the need for some flexibility, [and] I think we can address that as we move forward when we get into the more thorny issues and the other items that are not before us."

The nearly $24 billion in combined CPNY and CHPE contracts fall under the new Clean Energy Standard Tier 4 category of renewable energy credits (RECs) set up to bring renewable energy into the city by the commission, which set a Monday deadline for reply comments on the contracts.

CHPE said in its financing petition that it had withheld the expected amount of financing given certain competitive concerns, including bid preparation for the New York State Energy and Research Development Authority's (NYSERDA) Tier 4 solicitation.

Given that the NYSERDA Tier 4 solicitation has concluded, with the project being one of two award recipients, CHPE said in a supplement to the petition that it "will seek to raise debt financing in an amount not to exceed $4.5 billion." ■

The New York Public Service Commission on Feb. 17, conducted its regular monthly session both in person and via teleconference. | *NYDPS*

NYISO News

Con Edison 2021 Earnings Jump 22%

By Michael Kuser

Consolidated Edison's (NYSE: ED) *earnings* rose 22.3% to $1.35 billion ($3.86/share) last year on higher electric, gas and steam revenues, the company reported last week.

The company earned $224 million ($0.63/share) in the fourth quarter, compared with $43 million ($0.13/share) in the same period a year earlier, after winding down a loss related to its investment in the Mountain Valley Pipeline.

"Once again in 2021, our employees continued to provide safe, reliable service to our customers throughout the unprecedented challenges of the pandemic, and our focus on delivering investor value remains strong," CEO Timothy Cawley said in a statement. "Our expanded clean energy commitment reflects our dedication to lead the transition to renewables, gives our customers greater control over their energy use, and builds a more resilient grid."

Con Edison said it aims to invest in, build and operate innovative energy infrastructure, advance electrification of heating and transportation, and transition away from fossil fuels to a net-zero economy by 2050.

The company last month released an investment *plan* targeting capital investments this year of about $4.6 billion, and $11 billion in aggregate capital investments over 2023-24.

Con Edison also last month submitted to the New York Public Service Commission a rate case for an 11.8% increase in electric rates and higher gas rates to become effective next January (*22-E-0064*).

The timing of the rate hike request proved awkward, as within two weeks many city customers were shocked to see sharp increases in their monthly Con Ed bills.

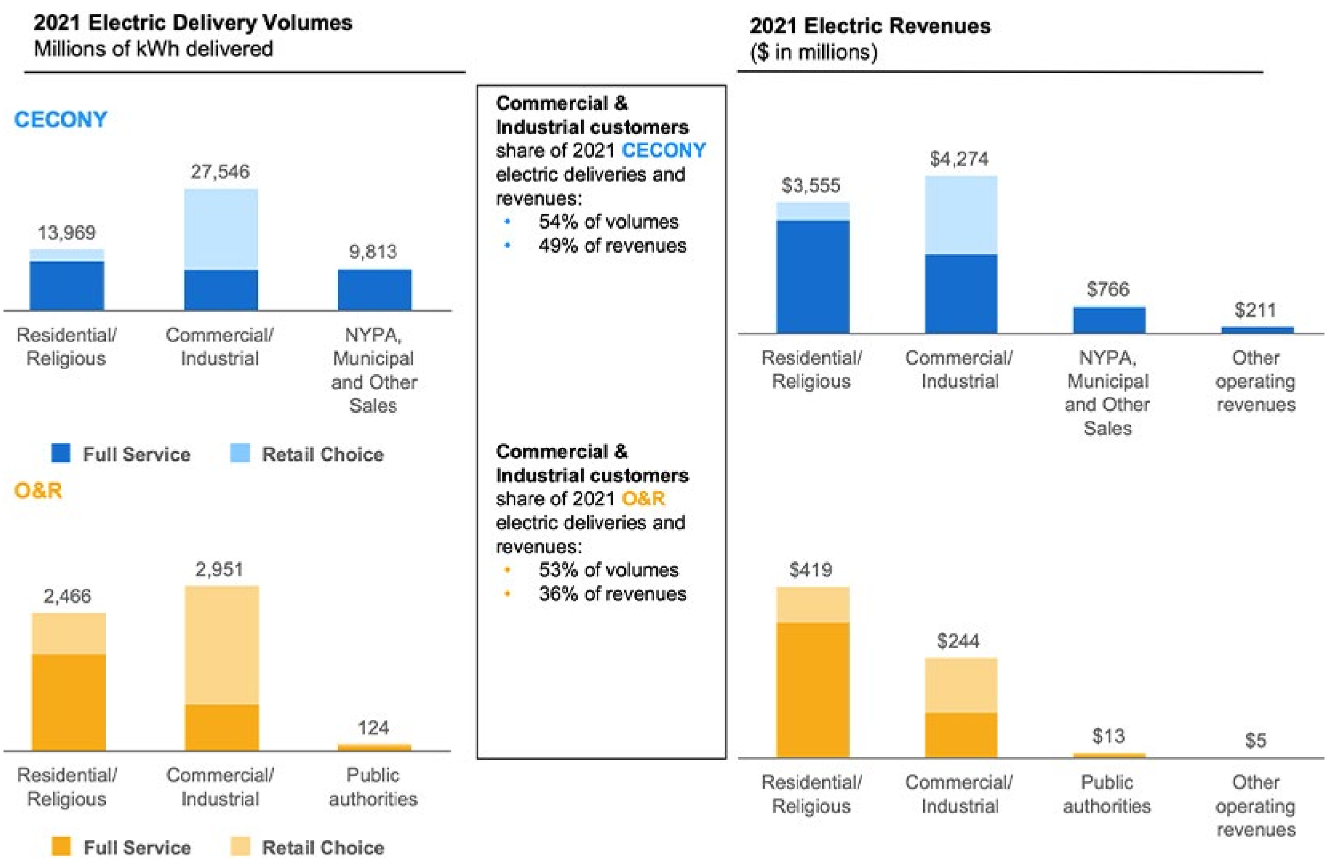
Gov. Kathy Hochul *asked* Con Edison to review its billing practices; she also announced increased relief efforts to reach low-income New Yorkers, making millions of dollars in aid available.

"Even though the spikes we are seeing in electricity, natural gas and fuel prices were predicted and are due to severe winter weather, I am calling on Con Ed to review their billing practices because we must take unified action to provide relief for New Yorkers, especially our most vulnerable residents," Hochul said.

Con Edison also must resolve several regulatory concerns before being authorized to build a new $4 billion substation complex in New York City dedicated to interconnecting offshore wind projects. (See *Con Ed to Refine $4B Offshore Tx Plan for NYC*.)

In October, Con Edison subsidiary Orange and Rockland Utilities (O&R) entered a joint proposal for new electric and gas rate plans for the three-year period through 2024, subject to regulatory approval.

Con Edison is one of the country's largest investor-owned utilities, with approximately $12 billion in annual revenues and $63 billion in assets. CECONY is its regulated utility providing electric, gas and steam service in New York City and Westchester County, New York, while O&R serves customers in a 1,300-square-mile-area in southeastern New York and northern New Jersey. ■



Con Edison's customer breakdown of electric deliveries and revenues in 2021 | *Con Edison*

PJM News

Powhatan Energy to Declare Bankruptcy

Energy Trading Company in Litigation with FERC

By Michael Yoder

Powhatan Energy Fund will file for Chapter 7 bankruptcy, a company representative said Thursday, effectively ending more than a decade of litigation and legal moves with FERC over a high-profile market manipulation case in PJM.

In an email to *RTO Insider*, Powhatan co-founder Kevin Gates said the Pennsylvania-based money management firm that once participated in PJM markets "does not have enough money to continue to litigate with the FERC over simple spread trades that took place almost 12 years ago" and decided to declare bankruptcy, unwinding the firm.

In 2015, FERC ordered Powhatan and one of its traders to pay $34.5 million in penalties and disgorged profits. The commission accepted the Office of Enforcement's findings that the company and trader Houlihan "Alan" Chen violated anti-manipulation rules by making riskless back-to-back up-to-congestion (UTC) trades to profit on line-loss rebates (*IN15-3*). (See *FERC Orders Gates, Powhatan to Pay $34.5 Million; Next Stop, Federal Court?*)

In July of that year, the commission filed suit in the U.S. District Court for the Eastern District of Virginia to request an order affirming FERC's orders assessing civil penalties, leading to several years of motions, countermotions and orders. Powhatan chronicled the legal back-and-forth on its *website*.

"We've already paid our attorneys many millions of dollars and simply do not have another million dollars to continue to defend ourselves from FERC's meritless assault," Kevin Gates said in the email.

The Case

Chen, who conducted the trades, began trading UTCs in 2007, after leaving Merrill Lynch, where FERC said he studied UTCs as a tool for physical and financial transactions.

Initially, Chen's trades were based on market fundamentals and models he developed using a "careful, low risk approach of what he called 'directional bets,'" FERC said. Most bids were under 100 MW, and his profitability depended on favorable price spreads.

In October 2009, after discovering he was receiving line-loss rebates, Chen switched to a strategy designed to capture increased volumes of rebates, FERC said.

His strategy changed again after suffering a $176,000 loss on May 30, 2010, when one leg of a trade saw an unexpected price spike. Following the loss, Chen switched to a round-trip trading strategy between the same two points (A-to-B, B-to-A) that FERC said made the underlying trades effectively riskless.

Kevin and Richard Gates | *Powhatan Energy Fund*

FERC sought penalties only for what it called the "manipulation period," from June 1 to August 3, 2010, when Chen stopped the trading after receiving a warning from PJM Market Monitor Joe Bowring.

FERC began investigating Chen and Powhatan, with Chen and the Gates brothers responding to FERC data requests and sitting for depositions while their lawyers sparred with FERC attorneys and provided affidavits from an economist and an attorney supporting their defense.

In October, FERC issued a *consent agreement* with Chen, with Chen agreeing to disgorge $600,000 to PJM.

Gates' Response

In 2015, Kevin Gates told *RTO Insider* that he rejected FERC's offer to enter settlement discussions after he, his brother and Chen had responded to data requests and sat for depositions while their lawyers continued to spar with the agency. In a Feb. 18 email, Gates said the company subsequently attended "like three court-mandated settlement discussions," none of which were productive.

The company did propose a *settlement* with FERC last June, which the commission turned down.

"Even though FERC's investigation began 4,201 days ago, we weren't even able to complete discovery as they threw up every possible roadblock they could think of to drag this case out and bleed us of resources," Gates said.

Gates said FERC "essentially has an unlimited budget" to litigate cases and is "happy to spend other people's money to promote their own agenda." He said FERC's "modus operandi" is to use litigation and their power to "extract massive, headline-grabbing settlements" from individuals and companies that don't want to engage in their defense in court.

"We suspect this will make the FERC happy," Kevin Gates wrote. "They have never sought the pursuit of justice, but rather used the administrative process and the legal system as a cudgel with which to bully us. FERC is part of the reason that citizens are losing faith in our government and a demonstration that bureaucrats sometimes deserve their worst stereotypes." ■

PJM News

FERC: PJM Right to Block Gen Stability Limit Payments

By Amanda Durish Cook

FERC on Thursday ruled that PJM is within its rights to refuse lost-opportunity cost payments to generators that must rein in output to avoid damage to themselves and keep the system stable.

The commission accepted PJM's clarifying changes to its tariff effective June 1 over protests from PJM Power Providers Group. The edits specify that the RTO doesn't need to compensate generators for temporary restrictions on output to prevent loss of synchronization and further system strain during transmission outages (*ER21-1802*).

PJM said some generators' expectation of lost-opportunity cost payments for maintaining stability limits is a "mistaken interpretation."

| © RTO Insider LLC

The RTO's tariff makes lost-opportunity cost payments when a generator's output is "reduced or suspended … at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue." PJM conceded that the "other reliability issue" language is vague and could be misconstrued by generation operators to expect payment for honoring system stability limits.

The grid operator filed the revisions in late April with its Independent Market Monitor's support. The RTO said paying lost-opportunity costs for "output limitations associated with stability limits is unnecessary because generators are already incentivized to operate within those limits."

PJM explained that if generators don't abide by generator stability limits, they risk damage to their own equipment. It said lost-opportunity costs are intended to motivate generators to forgo market revenues and voluntarily follow dispatch instructions when the transmission system is at risk.

The IMM agreed that "violating the stability limit is not rational behavior for the generator" and contended that generators have no lost opportunity to recoup.

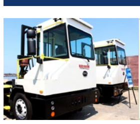
The PJM Power Providers Group argued that the RTO's edits "confiscate compensation owed to the generator for providing the reliability service of mitigating stability limits, while continuing to pay other generators for reducing output to provide reliability services" to protect the bulk electric system. The group said PJM's distinction was discriminatory and preferential and said the grid operator offered "no compelling reason for the unique treatment of generators following PJM reliability directives to honor a stability limit."

FERC said that generators "do not experience a lost opportunity when PJM directs them to back down due to a stability limit on the transmission system."

"We agree with PJM that generators are already sufficiently incentivized to operate within stability limits in order to avoid any potential physical harm to their resource, and therefore … payments are unnecessary," the commission said. "Violating a stability limit to achieve higher energy market revenues, at the risk of damaging the generating equipment, is neither rational nor economic behavior."

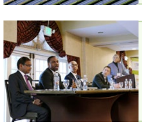
FERC agreed with PJM that its status as a NERC reliability coordinator obligate it to "prevent or mitigate damage to generating facilities" by establishing and enforcing stability limits. It added that the RTO is justified in treating different types of system limitations differently. ■

Mid-Atlantic news from our other channels



Enviros Want Faster Action on NJ Cargo-handling Emission Rules

NJ Lawmakers Push for Equity in Solar, Wind Energy Benefits



Md. Lawmakers Vow to up Climate Goals

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

PJM News

PJM MRC/MC Preview

Below is a summary of the consent agendas scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Thursday. Besides the consent agendas, the committees will not vote on any items at the meetings. The MRC will, however, hear first readings of seven different proposals, potentially teeing up as many votes at next month's meeting.

RTO Insider will be covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:15-9:20)

B. Stakeholders will be asked to *endorse* proposed conforming revisions to *Manual 27: Open Access Transmission Tariff Accounting* as a result of PJM's recent formula rate filing with FERC (ER22-26). (See *FERC Sets Hearing on Industrials' Challenge to PJM Administrative Rates*.)

C. Members will be asked to *endorse* proposed revisions to *Manual 40: Training and Certification Requirements* resulting from its periodic review. The changes were endorsed by the Operating Committee on Feb. 10. (See "Manual 40 Endorsed," *PJM Operating Committee Briefs: Feb. 10, 2022*.)

Members Committee

Consent Agenda (11:25-11:30)

C. The committee will be asked to *endorse* proposed revisions to the *Operating Agreement* and *Manual 15: Cost Development Guidelines* addressing clarifications to fuel-cost policy *standards* and Schedule 2 penalty revisions. Members unanimously endorsed the joint PJM/Independent Market Monitor proposal at the Jan. 26 MRC meeting. (See "Fuel-cost Policy Standard Clarifications Endorsed," *PJM MRC/MC Briefs: Jan. 26, 2022*.) ■

— Michael Yoder

MISO, PJM Weigh '22 Interregional Plan

By Amanda Durish Cook

MISO and PJM are assessing the need for an interregional study and transmission plan later this year, staffs told stakeholders during Thursday's Interregional Planning Stakeholder Advisory Committee (IPSAC) teleconference.

MISO engineer Ben Stearney said the RTOs are reviewing data and will announce within 45 days whether they see a need for an interregional study.

The grid operators late last year compiled and exchanged data on historical market-to-market congestion, regional issues, and newly approved projects near the seam. They said they will review their most highly congested transmission elements and possible mitigations and might pursue a "full or limited" targeted market efficiency project (TMEP) study this year.

Staff said they're also considering conducting a more specific analysis into the planning impacts of Illinois' Climate and Equitable Jobs Act, which targets 100% clean energy in the state by 2050.

For the past two years, MISO and PJM have decided against both the more involved coordinated system plan and a TMEP study, which produces smaller, congestion-relieving seams projects.

Days before the latest MISO-PJM IPSAC meeting, MISO and SPP announced they would conduct a TMEP-style study this year on some of their more heavily used flowgates. (See *MISO, SPP Take on 2nd Interregional Planning Effort*.)

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MISO isn't obligated to conduct an interregional study once every two years on its PJM seam, as it does with SPP. However, MISO and PJM have approved three small TMEP portfolios since 2017 and one larger *interregional market efficiency project* in northwest Indiana in 2020.

MISO's and PJM's TMEPs must cost less than $20 million, completely cover installed capital costs within four years of service, and be in service by the third summer peak from its approval. The projects are assessed using a shorter time horizon than interregional market efficiency projects. ■

PPL Announces Losses, Dividend Cut in Q4 Call

Acquisition of Narragansett Electric Could Happen in March

By Michael Yoder

PPL's stock price took a sharp hit Friday as the company announced during its fourth-quarter earnings call that it was cutting dividends in half and missed earnings and revenue targets.

The company announced it will reduce its quarterly common stock dividend to 20 cents/share from $41.5 cents last quarter. PPL's stock price dropped 7.25% in trading, finishing the day at $26.10.

CEO Vincent Sorgi said PPL's year was marked by a "strategic repositioning" of the company, including the sale of its U.K. utility business Western Power Distribution for 7.8 billion pounds ($10.7 billion) to National Grid and the purchase of the London-based company's Rhode Island utility, Narragansett Electric, for $3.8 billion. (See *PPL to Sell UK Business, Acquire Narragansett Electric*.)

"2021 was very much a transition year for PPL," Sorgi said. "It was about reimagining PPL and laying a firm foundation for the company's future growth and success, and I believe we achieved just that."

Narragansett Purchase

Sorgi said PPL anticipates receiving a final order from the Rhode Island Division of Public Utilities and Carriers regarding the Narragansett acquisition by March. PPL received FERC approval for the purchase in September, but the utility needs final approval from the PUC for the deal to go through. (See *FERC Approves PPL Acquisition of Narragansett*.)

Sorgi highlighted PPL's utility experience, customer satisfaction and innovation as reasons the company is confident it will ultimately win regulatory approval for Narragansett's acquisition. He said PPL has been a "clear leader" in the development and deployment of the kind of smart grid technology Rhode Island will need in achieving its decarbonization goals.

"We think we've met the standard for approval in the state, and we are looking forward to the decision coming out from the division," Sorgi said. "We are all very focused on getting this deal over the goal line and bringing real value to our line."

Infrastructure and Storm Damage

Sorgi also highlighted PPL's response to significant storm damage in its service area,

PPL headquarters in Allentown, Pa. | *PPL*

including a major December tornado outbreak in Kentucky and the remnants of Hurricane Ida in Pennsylvania in September.

More than 500 transmission and distribution poles were destroyed from the storms in Kentucky, Sorgi said, but PPL restored power to most of its customers within 48 hours. Crews were also able to restore power in Pennsylvania despite historic flooding from the hurricane, Sorgi said, and PPL was recognized with an Edison Electric Institute Emergency Response Award for its restoration performance.

"When severe weather struck either in Pennsylvania or Kentucky, we responded quickly and effectively," Sorgi said. "This performance is the result of the investments we have made in our grid and our dedicated employees who pride themselves on delivering the superior level of service each day."

CFO Joe Bergstein said the capital investments made in the states last year aided in the support of grid modernization, resilience and reliability. In Pennsylvania, the company focused on distribution reliability and advancing IT systems, while transmission investments included smart relays, equipment monitoring and automation. Kentucky investments were primarily related to replacing aging transmission infrastructure, resulting in a total rate-base growth of about 6% in the state even as rates related to coal-fired generation facilities fell.

Operating Results

Friday's lowered dividend payment was based on projected earnings per share from PPL's existing business operations in Pennsylvania and Kentucky and the company's targeted payout ratio of 60 to 65%. Because earnings from the former U.K. operation are now excluded, using the targeted payout ratio, the dividend was reduced.

The fourth-quarter earnings included special expenses of $29 million linked to the Narragansett acquisition and the sale of its U.K. utility.

The company reported a 2021 net loss of $1.48 billion ($1.93/share), compared with $1.47 billion ($1.91/share) in 2020. The earnings losses included special-item after-tax expenses of $2.29 billion ($2.98 per share) attributed to the discontinued U.K. operations, a U.K. tax rate change and a loss on the "early extinguishment" of debt.

However, earnings from ongoing operations in 2021, which excludes special items, was $806 million ($1.05/share), compared to $774 million ($1/share) in 2020. The company reported quarterly earnings of $134 million ($0.18/share), compared with $290 million ($0.38/share) in the fourth quarter of 2020.

PPL reduced its debt position by $3.5 billion, and it completed $1 billion in stock repurchases. Bergstein said the debt reduction was "one of the key financial highlights for 2021," with a significant amount of the sale of WPD proceeds going to "strengthen PPL's balance sheet."

"We had a unique opportunity to establish one of the leading credit profiles in the sector, an attribute we see is increasingly important with the growing capital needs to fund the clean energy transition and now amid the backdrop of rising interest rates," Bergstein said. ■

FERC Approves Pause of PJM Tx Constraint Penalty Factor in Va.

Line Work in Northern Neck Va. Causing 'Unjust' Rates

By Michael Yoder

FERC on Friday accepted revisions to PJM's tariff and Operating Agreement that temporarily remove transmission constraint penalty factor (TCPF) rules in Virginia's Northern Neck peninsula (*EL22-26, ER22-957*).

The peninsula, which encompasses Lancaster, Northumberland, Richmond and Westmoreland counties, is normally served by three transmission lines: a 230-kV line from Fredericksburg, a 230-kV from Lanexa-Dunnsville and a 115-kV line Harmony Village. But as part of a transmission upgrade project approved in 2020, PJM placed the Lanexa-Dunnsville line on outage at the beginning of the year.

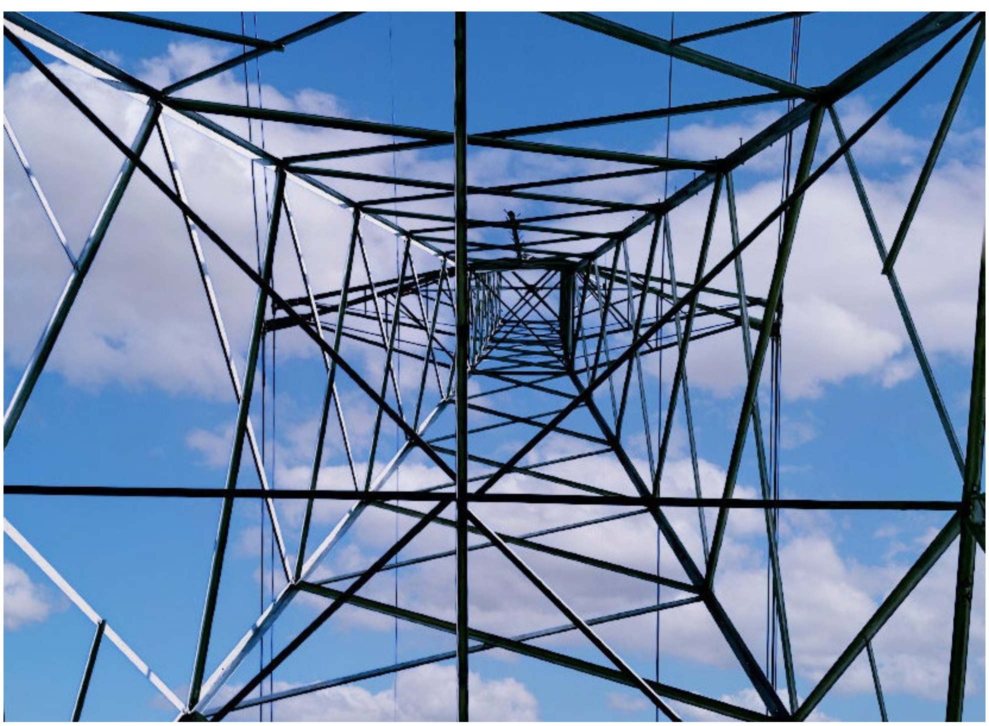
That immediately created price fluctuations of the TCPF to its default rate of $2,000/MWh in the real-time energy market. PJM on Jan. 31 told FERC that the TCPF rules were creating "unjust and unreasonable energy market rates" for consumers on the peninsula.

The RTO also said the price fluctuations contributed to the default in January of Hill Energy Resource & Services, which had portfolio positions in the financial transmission rights market in the congested Dominion zone. (See *PJM Weighs Options on Hill Energy FTR Default*.)

TCPFs provide price signals to incent more supply or demand response. But the Northern Neck has a "few relatively small" combustion turbines, PJM told FERC, and load has not "responded significantly enough." The line outage has resulted in "repeated instances" when no actions can relieve the transmission constraint on the other two lines, causing real-time energy market prices to oscillate between the offers of the CT plants and the TCPF of $2,000/MWh, even in the early morning hours, when behind-the-meter solar resources located on the peninsula are usually enough.

"PJM has shown that under the specific circumstances in the record, the transmission constraint penalty factor is not achieving its intended purpose in the Northern Neck peninsula and is resulting in an inappropriate price signal that establishes high prices without a commensurate benefit," the commission said. "We therefore agree that it is just and reasonable to stop applying the transmission constraint penalty factor in the Northern Neck peninsula for a limited time."

The RTO said the situation is expected to continue throughout the life of the project until its completion in December 2023, resulting in "significant increases in costs to load," without an "amendment to the existing transmission constraint penalty factor rules."



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To solve the pricing issue, PJM proposed setting the transmission line limit "at a level that ensures the offers of the resources being used to control the constraint are reflected in the congestion price in lieu of applying a transmission constraint penalty factor."

The RTO also proposed providing "regular informational filings" to the commission regarding congestion on the peninsula and to work with stakeholders on reforms to the TCPF rules if a similar situation happens in the future.

PJM requested an effective date of Feb. 1, 2022, one day after the date of its filings, because "recalculating energy market settlements is labor intensive, especially over an extended period of time."

Protests

Several stakeholders protested PJM's proposed changes.

Chicago-based hedge fund Citadel argued that PJM failed to demonstrate the existing TCPF rules were unjust and unreasonable. The company said PJM recorded recent scarcity pricing on the same path in August and December of 2020 and August 2021 and did not demonstrate how customers were harmed during those events and did not raise concerns at the time of those events. Citadel said there were 784 real-time intervals of prices reaching $2,000/MWh during the previous outages on the line, which "did not prompt PJM to make an emergency filing."

DC Energy also said the outages in 2020 and 2021 created "substantially similar conditions on the remaining facilities serving Virginia's Northern Neck" and argued that "emergency measures to eliminate the scarcity pricing signal were not justified in those circumstances and they are not justified now."

Citadel also argued that "PJM should focus on ways to accelerate new generation development in this location as opposed to creating uncertainty around existing, market-based price signals." The company said more than 700 MW of new solar, battery, and solar-battery facilities are planned to come online in the peninsula during or shortly after the period of the transmission outage.

Appian Way said that, because this case in-

PJM News

volves the Hill Energy default, PJM "may have responded with an excessive and unwarranted level of political sensitivity due to the historical context of the GreenHat" Energy default of 2018.

The commission said that while PJM has an existing process to temporarily relax the TCPF, the existing provisions "do not contemplate the unique scenario presented here."

"Based on the evidence in the record, we find that PJM's continued application of the transmission constraint penalty factor to congestion in the Northern Neck region resulting from the Lanexa-Dunnsville-Northern Neck line outage will not produce the intended short-term or long-term responses and, instead, will only result in higher costs to ratepayers without a commensurate benefit," FERC said.

The commission said it agreed with PJM that new generation resources sufficient to relieve the constraint "could not reasonably be expected to be sited, constructed and complete the PJM interconnection process before December 2023."

FERC also disagreed with Citadel's argument that PJM failed to provide enough evidence for its proposal. The commission said PJM provided LMP data for the Northern Neck on Jan. 14, as well as for the period Feb. 1-14. The data were "sufficient to demonstrate the link between high prices and the transmission constraint penalty factor."

The commission also disagreed with DC Energy's and Citadel's assertions that past incidences of high prices in the same area of the Dominion zone "demonstrate that PJM's current tariff is not unjust and unreasonable." It said the findings were "grounded in the unique circumstances" in the proceeding.

It directed PJM to submit an informational filing updating the commission on congestion patterns within 90 days of the date of the order and every 90 days after until the Lanexa-Dunnsville line upgrade is complete. The RTO was also encouraged to "consider modifications to its analyses of and planning for transmission outages to prevent such occurrences in the future."

Danly Dissent

FERC Commissioner James Danly provided the lone dissent on the order, saying he disagreed that PJM met its Section 206 burden to demonstrate the existing transmission constraint penalty factor tariff rate is unjust and unreasonable

"As best I can make out, the high prices required by the tariff in the face of an unresolvable constraint are both too high for PJM's liking but are simultaneously an insufficient incentive for anyone to do anything about it," Danly said. "I am suspicious that this is a case of scarcity pricing being allowed in a market tariff only until it actually occurs, and then it must be eradicated. Markets cannot work when high prices that occur by design are disallowed in practice."

Danly said it "does appear" that there may not be a short-term solution to the pricing issue, but he said he was "skeptical" that three weeks was a sufficient amount of time to make the determination. He said he was also concerned by the "regulatory uncertainty" making the change could cause.

"I cannot imagine how an existing generation resource in PJM can remain in business given the frequency of changes the commission repeatedly imposes on these markets, all tending to reduce prices for existing generation," Danly said. "Today, we reduce price again, demonstrating to everyone that the mechanisms we put in place to harness market forces will be abandoned when they work as planned." ■

SPP News

KEPCo, Xcel Rehearing Requests on Z2 Fail

FERC also Clarifies Decision in AEP Network Upgrade Cost Docket

By Tom Kleckner

FERC on Thursday rejected a pair of separate rehearing requests by SPP members related to the RTO's assignment of network upgrade charges under Attachment Z2 of its tariff.

The commission affirmed its original decisions involving Kansas Electric Power Cooperative (KEPCo) and Xcel Energy operating company subsidiary Southwestern Public Service (SPS) that SPP's assignment of network upgrade costs did not violate the utility's service agreements or the RTO's tariff (*EL17-21*, *EL18-9*).

Attachment Z2 promised transmission upgrade sponsors would receive credits from any upgrade users whose service could not be provided "but for" the upgrade. But section I.7.1 of SPP's tariff also required the RTO to invoice the charges monthly and to make any adjustments within one year. Because of software problems, it took SPP eight years to implement the attachment, during which the RTO did not invoice for the upgrade charges.

KEPCo had argued that SPP inappropriately assigned $6.2 million in upgrade costs in violation of four separate network integration transmission service agreements (NITSAs), with which FERC in November 2017 disagreed.

In its rehearing request, KEPCo maintained that SPP violated the filed-rate doctrine by assigning to the cooperative credit payment obligations (CPOs) for upgrades not listed in the NITSAs, saying FERC's holding to the contrary is "based exclusively on the finding that KEPCo had sufficient notice of possible Z2 credit payment obligations."

The cooperative also alleged the commission's order did not address the NITSAs' structure and its argument that SPP may not retroactively assess costs not specified in the NITSAs. It disputed the determination that it was on notice of possible Z2 responsibility and contends that the commission "does not explain why such notice — neither of which is contained in the [NITSAs] or tariff — is sufficient to make KEPCo liable" for CPOs not otherwise specified in the NITSAs.

FERC disagreed, saying that in 2017, SPP did not have a tariff requirement specifying Z2 upgrades must be listed in NITSAs. It noted that the attachment is the governing tariff provision and "sets forth an expectation that sponsors will receive reimbursement from subsequent users that derive beneficial use of those upgrades."

Referring to the 2017 order, the commission said the NITSAs are part of and "subject to the terms of the tariff, which bound KEPCo to the obligations imposed under Attachment Z2." FERC said the filed rate included Attachment Z2, through which KEPCo was on notice of the possibility of CPOs that occur within the tariff's billing requirements.

The commission had granted SPP a retroactive waiver of its tariff in 2016 so that it could invoice transmission service customers for Z2 credit payment obligations for 2008-2016 (ER16-1341). But it reversed course in 2019, saying its original decision was prohibited by the filed-rate doctrine and the rule against retroactive ratemaking. (See *FERC Reverses Waiver on SPP's Z2 Obligations*.)

The D.C. Circuit Court of Appeals upheld FERC's reversal of the retroactive waiver in August. (See *DC Circuit Upholds FERC Ruling on SPP Z2 Saga*.)

While saying KEPCO no longer has any CPOs during the historical period, FERC found that Attachment Z2, the filed rate, did provide notice of prospective CPOs that did not require waiver of the tariff's billing requirements.

"The fact that these charges were not specified in the NITSAs does not relieve KEPCo of its obligation under the tariff to reimburse sponsors for the costs of network upgrades from which KEPCo derives beneficial use," the commission wrote. "Accordingly, we continue to find that there has been no violation of the filed-rate doctrine for charges assessed after the historical period."

Xcel alleged that SPP's Attachment Z2 implementation violated the tariff and filed-rate doctrine because the grid operator failed to appropriately apply the "but for" test set forth in the tariff. It said the attachment "unambiguously" provides for CPOs to subsequent service requests that "could not be provided but for" the creditable upgrade.

In denying Xcel's rehearing request of a 2018 order, FERC continued to find that SPP did not violate the tariff or the filed-rate doctrine in assigning CPOs to SPS. It also rejected Xcel's contention that SPP's assignment of CPOs was not sufficiently transparent and was unjust and unreasonable. The commission said Xcel did not identify any particular payment obligation or what type of support it asserts is lacking. It noted that FERC said in its 2018 order that SPP market participants had various channels by which to examine costs, including one-on-one sessions, and noted that Xcel could and should have taken advantage of those channels.

AEP Rehearing Request Rejected

FERC also granted American Electric Power's clarification of a 2018 order accepting SPP's filing of an unexecuted NITSA while affirming its previous decision (*ER18-1702*).

SPP made the filing after AEP declined to execute the revised service agreement because of nonconforming terms and conditions in the RTO's tariff. AEP asked for a rehearing of the proceeding, alleging that the commission erred in failing to consider specific concerns regarding the applicability of completed aggregate facilities study (AFS) agreements, which the company said reflect an agreement that it need not pay for directly assigned network upgrade costs.

AEP asserted the charges included in the unexecuted NITSA were "plainly inconsistent" with its completed AFS agreement that outlined the terms under which a customer would agree to take transmission service. The company argued those terms "included a clear indication that AEP desired to make no payment for" directly assigned network upgrade costs.

It said that unless the AFS agreements' terms are binding on SPP, they serve as "a vehicle for SPP to falsely induce customers into taking service under certain terms and conditions and later changes those terms and conditions without any recourse or protection to the customer."

The commission granted AEP's clarification request that it will consider the completed AFS agreements' applicability in the ongoing proceeding to determine how SPP can unwind and resettle CPOs (16-1341).

But it also continued to find that that the issue is whether SPP "has appropriately included certain information in the service agreements pursuant to its tariff" and not administering its Attachment Z2 process during a prior period. The commission said the D.C. Circuit's decision to uphold FERC's reversal of the retroactive waiver granted to SPP rendered AEP's protest moot. ■

SPP News

SPP Briefs

SPP Reaches out to Public Interest Organizations

Faced with a rapidly evolving grid's continued focus on decarbonization and a resource mix to match, SPP is working to strengthen its relationship with public interest organizations (PIOs) and the interests they represent.

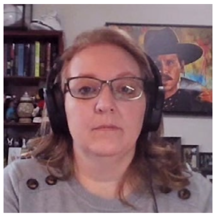
Staff told the Corporate Governance Committee (CGC) on Thursday that they have held two meetings this year with PIOs and stakeholders to discussion the grid operator's governance structure and their straw proposals.

The subjects have included expanding qualifications to sit on the Board of Directors and the Nominating Committee's search criteria; eliminating membership withdrawal deposits for PIOs; adding even more transparency to SPP meetings; and providing a role for Western regulators before their utilities become RTO members.

"I'm encouraged by the nature of the conversations that are taking place," board Chair Larry Altenbaumer said.

Staff said they find PIOs offer value to SPP because they have "an unbiased perspective" in reviewing policy and market design proposals that serve the larger interests and because they tend to be actively engaged in state, regional and interconnection-wide generation, and regional market and transmission planning forums, particularly in the Western Interconnection.

Their participation is motivated by the end state of evolving market design and rules to support future technology. SPP says a decarbonized grid is essential and the evolving grid's economics warrant change, including regional coordination of energy needs.



Kylah McNabb, Sustainable FERC Project | *SPP*

"We're very, very encouraged with the past few months and very, very encouraged by the items under consideration," said Kylah McNabb, an energy consultant representing the Sustainable FERC Project. "We do understand it's a process. Taking a look at these items is the start of a larger conversation that will take place in coming weeks."

McNabb indicated to the CGC that her organization is all but certain to soon submit its membership application to SPP. The organization, based in Oklahoma City, is a partnership of state, regional and national environmental and other PIOs working to expand clean energy's deployment and to reduce and eventually eliminate carbon pollution from the power sector.

SPP currently has only one PIO member in the Lignite Energy Council. However, that sector could grow should the RTO reclassify alternative power members Advanced Power Alliance (APA) and American Clean Power Association, the grid operator's newest and 110th member, as PIOs.

Western Resource Advocates, which spoke for consumers during SPP's failed bid to integrate the Mountain West Transmission Group, is also considering membership in the RTO. (See *Xcel Leaving Mountain West; SPP Integration at Risk*.)

Steve Gaw, Advanced Power Allliance | *© RTO Insider LLC*

APA's Steve Gaw, who helped facilitate the discussions with the PIOs, said, "There's still more conversation ahead on this. When I look at the issues that are there, I feel like the attempts to find paths forward have been very positive and help educate and understanding on both sides has been worthwhile."

SPP said it is pursuing "something more appropriate" for PIOs related to their membership withdrawal deposits. Staff have proposed three categories: $150,000 for load-serving entities, $50,000 for non-LSEs, and $12,000 for PIOs, consumer advocates and other similar groups.

CGC OKs Future Grid Group

The CGC approved the 17-person roster for the Future Grid Strategy Advisory Group, which will be responsible for providing periodic assessments of the RTO grid's future state.

"We're very pleased. … We really hit a home run with what we've got here," COO Lanny Nickell said in presenting the group's nominations, a reference to the group's wide range of expertise. Its members represent investor-owned utilities, public power and governmental agencies, and independent transmission companies, while bringing expertise in transmission and generation planning and regulatory backgrounds.

Noting 11 of the members are in upper management, Nickell said, "I think we hit the mark there, as well."

The group was approved in December and will identify gaps between future state projections and current trajectories, and increase organizational awareness of opportunities to shape the grid.

The team is chaired by Mark Ahlstrom, vice president of renewable energy policy for NextEra Energy Resources, with SPP's chief information security officer, Sam Ellis, serving as staff secretary. The advisory group's full roster can be found *here*.

The CGC also recommended:

- that Google's Will Conkling replace Jeff Riles, who recently left the company to be director of energy markets at Microsoft, as the large retail sector's representative on the Members Committee; and
- EDF Renewables' Arash Ghodsian to be chair of the Generation Interconnection User Forum.

Committee members met in executive session to discuss the board vacancy created by Graham Edwards' departure at the end of last year. The search process for his replacement didn't begin in time to be included with the selection of SPP's two newest board members, cyber expert Ben Trowbridge and utility veteran John Cupparo. (See "Members Elect 2 New Directors," *SPP Board of Directors/Members Committee Briefs: Jan. 25, 2022*.)

M2M Settlements Reach $243M

SPP accrued $29.39 million in market-to-market (M2M) settlements from MISO during November in what staff termed "a very exciting month" during Friday's Seams Advisory Group meeting.

The total was the second highest since the RTOs began the M2M process in March 2015, exceeded only by the massive $51.49 million settlement in MISO's favor last February, in large part because of that month's severe winter storm.

Staff said the M2M process also settled in SPP's favor in December at $10.25 million. It was the 10th straight month the process settlements have been in the green for SPP and the 25th time in the last 27 months. Settlements in SPP's favor now total $243.31 million.

SPP News

Permanent and temporary flowgates were binding for more than 5,700 hours in November and December, compared to 1,875 hours in October. The grid operators exchange settlements for redispatch based on the non-monitoring RTO's market flow in relation to firm-flow entitlements.

Staff's Neil Robertson told SAG members that SPP and MISO are planning a series of stakeholder meetings through midyear to discuss cost allocation for their joint targeted interconnection queue (JTIQ) study, which last month identified a $1.755 billion portfolio of suggested projects. (See *MISO, SPP Roll out $1.755B Joint Tx Portfolio*.)

The grid operators will also raise the subject during today's *meeting* of their state commissions' staffs as they look to involve the regulatory community.

"We're better off trying to get onto the front end versus waiting for a baby to be dropped on the doorstep," said Adam McKinnie, an economist with the Missouri Public Service Commission.

Robertson also said the Joint Planning Committee, comprising single representatives from MISO and SPP, will soon meet to consider suggested projects submitted during the grid operators' Feb. 15 Interregional Planning Stakeholder Advisory Committee meeting. The grid operators plan to conduct a targeted market efficiency project (TMEP) study this year, focusing on smaller projects Robertson referred to as "TMEP-like". (See *MISO, SPP Take on 2nd Interregional Planning Effort*.)

The RTOs expect to complete the study's report and recommendations in August.

In reviewing their 2022 SAG work plan, members added a placeholder for Western services expansion to account for SPP's many initiatives in the Western Interconnection. The group's work plan also includes support for the TMEP development and JTIQ cost allocation work, and supporting SPP with seams-related activities in executing the RTO's strategic plan.

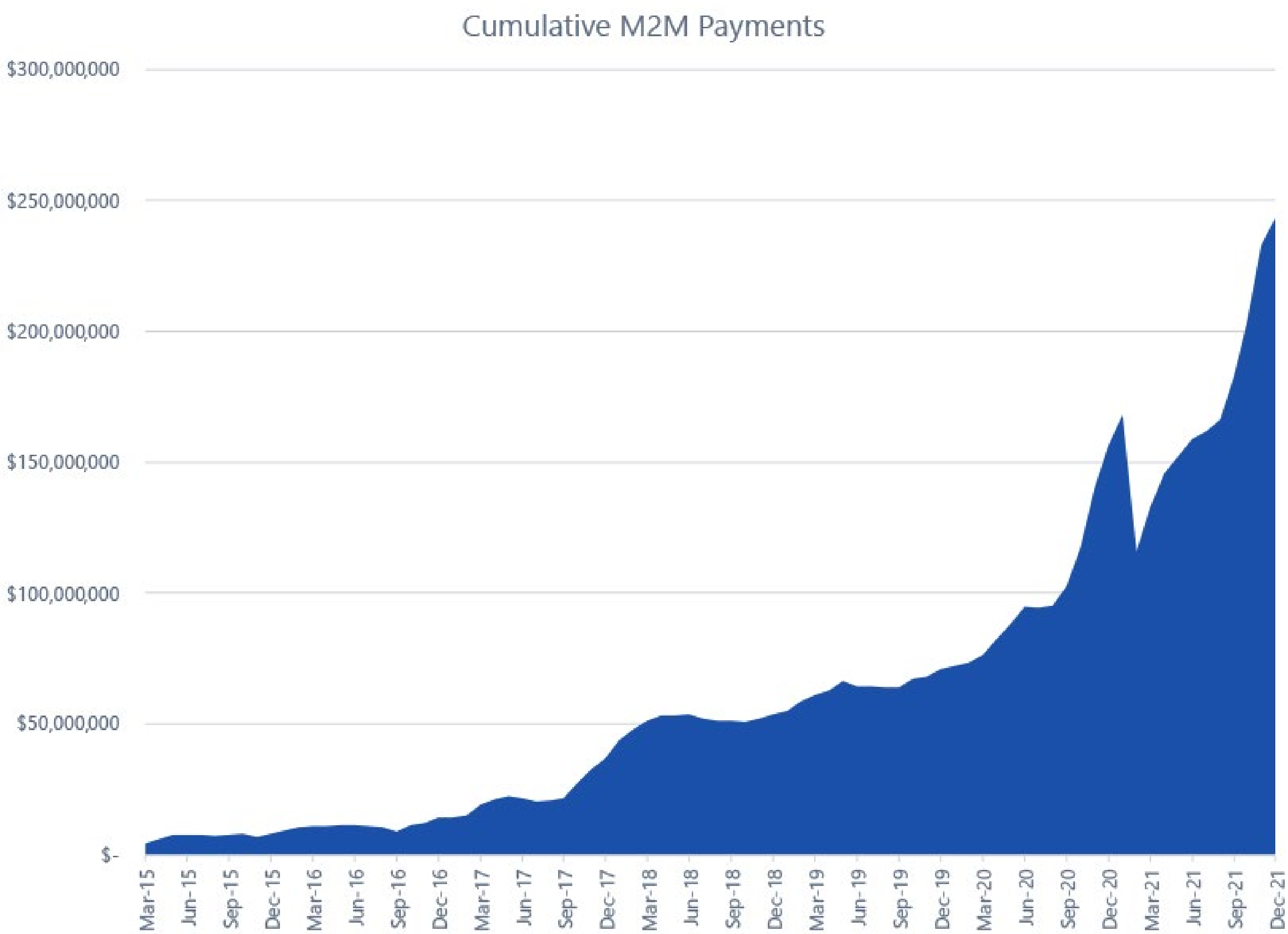
MOPC, Board Meetings Moved to Dallas

SPP has moved its April governance meetings, originally scheduled for Little Rock, Ark., and Kansas City, MO., to Dallas because of "challenges and uncertainty" its stakeholders have faced in making travel arrangements.

The Markets and Operations Policy Committee will be held April 11-12 and the Strategic Planning Committee on April 13. The Regional State Committee and quarterly joint stakeholder update is scheduled for April 25, with the board and Members Committee meeting April 26.

SPP encouraged stakeholders who are sick or who have been in close contact with someone infected with COVID to participate online. Unvaccinated attendees are "encouraged" to wear masks, but social distancing will not be enforced because of space limitations. ■

— Tom Kleckner



The accruing settlements from MISO to SPP since the RTOs began their market-to-market process in 2015 | *SPP*

Company Briefs

EV Maker Envirotech Plans Manufacturing Center in Arkansas

Electric vehicle maker Envirotech Vehicles, based in California, last week announced plans to open its first U.S. manufacturing facility in Arkansas.

The company said it has entered into a purchase agreement for a facility and expects to begin operations soon. Envirotech did not disclose the location of the facility, but an offer letter to the company's new CFO says he will be expected to work at its office in Osceola.

Envirotech is the second EV maker with plans to set up shop in Arkansas. In November, Canoo announced it would move its headquarters to the state.

More: *Arkansas Business*

GM Extends EV Bolt Production Halt

General Motors last week said it is extending a production halt of its Chevrolet Bolt electric vehicle following a recall but plans to resume retail sales soon.

GM said it plans to resume production of the Bolt at its Orion Township, Mich., plant the week of April 4. The National Highway Traffic Safety Administration also said it was closing an investigation into the Bolt fires "in view of the recall actions being taken by General Motors."

The company in August widened a recall of the Bolt to more than 140,000 vehicles to replace battery modules after a series of fires in parked vehicles, and halted production and retail sales.

More: *Reuters*

Nissan to Produce EVs in Mississippi

Nissan officials last week announced that the company will manufacture two new models of all-electric vehicles in Mississippi.

The company said it will invest $500 million in its Canton Vehicle Assembly Plant, which will produce new Nissan and Infiniti EVs beginning in 2025.

The state of Mississippi is providing assistance for building improvements, equipment installation and workforce training for Nissan's electric vehicle project.

More: *The Associated Press*

PSEG Completes Sale of Fossil Plants to ArcLight Capital Partners

The Public Service Enterprise Group (PSEG) last week completed the previously announced sale of its Fossil generating assets located in New Jersey and Maryland to ArcLight Capital Partners.

Completion of the sale concludes one of two transactions that together comprise the sale of PSEG Fossil's 6,750-MW portfolio of 13 fossil generation units in New Jersey, Connecticut, Maryland and New York. PSEG anticipates completing the sale of its New York and Connecticut assets within the current quarter.

Financials may be released during the company's quarterly earnings call.

More: *PSEG*

Federal Briefs

Courts Deal Blow to Southeastern Montana Coal Mine

In a Feb. 11 order, Magistrate Judge **Timothy Cavan** said the Office of Surface Mining Reclamation and Enforcement violated the National Environmental Policy Act by failing to take a hard look at how expanding the Rosebud Mine would impact water quantity and quality. With that, the office must redo its analysis of the 6,500-acre expansion.

Cavan also said the government should have weighed the costs of greenhouse gas emissions in its project analysis, given that it listed expected socioeconomic benefits.

The expansion of the mine, operated by Westmoreland Rosebud Mining, LLC, increases its size by 25%. If approved, the expansion is expected to yield 70.8 million tons of coal and extend its operational life by eight years, Cavan's order said.

More: *Montana Free Press*

Entergy Gets Reduced ARR on Choctaw

FERC last week approved Entergy Mississippi's settlement pertaining to the annual revenue requirement (ARR) of its natural gas-fired, 899-MW Choctaw County Generating Station.

The settlement temporarily reduces Choctaw's ARR for reactive power services by 15% from Dec. 1, 2020, until Entergy can attest through a FERC filing that Choctaw is physically disconnected from the Tennessee Valley Authority's transmission system. FERC asked Entergy to make the filing proving Choctaw's independence from TVA's system no later than Dec. 1, 2024.

Under the reduction, Entergy will receive a $1.62 million ARR instead of the $1.9 million it could collect if it proves disconnection from TVA. Entergy originally proposed a $5 million ARR for reactive service provided from Choctaw in September 2020. FERC in late 2020 said that amount could be unreasonable and set the matter for settlement procedures. Entergy proposed the settlement in November.

More: *ER20-2550-003*

Judge Declines to Toss Charges Against Madigan's Inner Circle

U.S. District Judge Harry Leinenweber last week declined to toss federal charges against four members of Illinois ex-House Speaker Michael Madigan's inner circle, saying the group allegedly "offered, or intended to offer, financial incentives as a bribe to a public official to influence state laws governing the public corporation that employed them."

Charged in a November 2020 indictment were Madigan confidant Michael McClain, ex-ComEd CEO Anne Pramaggiore, ex-top ComEd lobbyist John Hooker and Jay Doherty, the former president of the Chicago City Club. The four were accused of arranging for Madigan's associates and allies to get jobs, contracts and money in order to influence Madigan in the Legislature.

A hearing in the case against McClain, Pramaggiore, Hooker and Doherty is set for March 23. A trial in the case is set for Sept. 12.

More: *Chicago Sun-Times*

Major Banks Pledging Net Zero Still Financing Coal

Financial institutions channeled more than $1.5 trillion into the coal industry in loans and underwriting from January 2019 to November 2021, even though many have made net-zero pledges, a report by a group of 28 non-government organizations showed.

Reducing coal use is key to slashing greenhouse gases and bringing emissions down to "net zero" by the middle of the century, and governments, firms and financial institutions across the world have pledged to act. However, banks continue to fund 1,032 firms involved in the mining, trading, transportation and use of coal, the research showed.

The study said banks from six countries — China, the U.S., Japan, India, Britain and Canada — were responsible for 86% of global coal financing over the period. Direct loans amounted to $373 billion, while another $1.2 trillion was channeled to coal firms via underwriting. Institutional investments in coal firms over the period amounted to $469 billion.

More: *CNN*

Senator Blocks Biden EPA Nominees over Carbon Capture

Republican Sen. Bill Cassidy (La.) last week said he is blocking President Biden's nominees for environmental regulatory positions in a bid to win permission for his state to regulate the storage of carbon.

Louisiana, one of the top U.S. oil- and gas-producing states, has applied for the power to approve permits for and monitor wells that store carbon dioxide. Two other states, Wyoming and North Dakota, have been authorized to do that.

Cassidy's stance prevents Senate floor votes on nominees at the EPA.

More: *Reuters*

State Briefs

CALIFORNIA

Moss Landing Reports Second Malfunction in 5 Months

Firefighters last week responded to another battery meltdown at the Vistra Moss Landing energy storage facility — the second incident at the plant in the last five months.

Firefighters said roughly 10 battery racks were melted when they arrived on scene.

The facility is owned and operated by Vistra, which opened the plant in December 2020. Last month the company announced plans for an expansion project that will nearly double its capacity.

More: *KSBW*

COLORADO

Xcel Explains Reason Behind Comanche 3 Shutdown

The Public Utilities Commission last week ordered Xcel Energy, the operator of the Comanche 3 Power Generating Station, to provide a report explaining why the coal-fired generator stopped operating on Feb. 3 and whether the shutdown could affect service for customers.

In a letter to the PUC, company Vice President of Rates and Regulatory Affairs Brooke Trammell said the outage was triggered by electrical problems and will not affect the system's reliability. She said that workers would have to disassemble the generator. Commissioner John C. Gavan asked Xcel to provide an incident report as soon as possible.

Xcel is proposing to close the plant by the end of 2034 to keep in line with the state's greenhouse gas reduction targets for the company.

More: *CPR News*

GEORGIA

Plant Vogtle Reactors See Another Setback, Delayed at Least 3 Months

Further setbacks of the Plant Vogtle nuclear expansion are reportedly expected to result in delays lasting up to six months.

The operator added a $920 million charge at the end of last year.

Southern Co. and its subsidiary Georgia Power last week said the completion of the plant's third and fourth reactors are now projected to be delayed three-to-six months, with the third unit coming online in March 2023 and the final reactor ready by the end of that year.

Vogtle's expansion construction costs are expected to rise to more than $30 billion, up from an initial estimate of $14 billion in 2012. As part of an agreement with Georgia Power, the $920 million charge includes $440 million from other utilities involved in the project.

More: *Georgia Recorder*

ILLINOIS

Ameren to Buy Solar Project from Invenergy

Ameren Missouri last week announced it will acquire a 150-MW solar project being developed by Invenergy.

Located in southeastern Illinois, the solar photovoltaic plant could start commercial operations as early as 2024.

Financials of the deal were not disclosed.

More: *Renewables Now*

MINNESOTA

PUC Wants Xcel to Cut Wait Time to Connect Solar

The Public Utilities Commission last month instructed Xcel Energy to start evaluating multiple applications at once to clear its solar project backlog, which exceeds 1,700 projects totaling about 490 MW.

The PUC's instruction wants Xcel to implement a new process in which it will conduct group or cluster studies that assess the grid impact of multiple connection requests. The utility will also pilot a cost-sharing program to prevent individual projects from being overly burdened by expensive upgrades that will also benefit future applicants.

The number of requests to connect to Xcel's grid has surged in recent years. While critics blame Xcel's interpretation of the state's interconnection rules, the company claims it was prohibited from processing more than one application at a time for each substation.

More: *Energy News Network*

MONTANA

Bitcoin Miners Revive Dying Coal Plant

Marathon, a bitcoin "mining" company that purchased the 115-MW coal-fired Hardin generating station in 2020, has since revived the plant, which produced 5,000% more carbon dioxide in the second quarter of 2021 than it did the year before.

In the third quarter of 2021, an additional 206,000 tons of CO_2 was emitted, a 905% increase from 2020, EPA data shows. Hardin was operating at "near full capacity," Marathon said in a December update.

The plant was slated for closure in 2018 before being bought by Marathon. The company has since built a data center next to the facility that houses more than 30,000 Antminer S19 units, a specialized computer that mines for bitcoin.

More: *The Guardian*

NEW MEXICO

Clean Fuel Standard Act Fails on Tied House Vote

The House of Representatives last week voted 33-33, rejecting a bill aimed at reducing the carbon intensity of transportation fuels.

The will would have required a 20% reduction in carbon intensity of transportation fuels refined, blended or produced in the state by 2030 from the 2018 levels and a 30% reduction in carbon intensity by 2040. The bill also included provisions intended to increase expansion of electric vehicle infrastructure in rural and low-income communities.

Legislators can bring the bill for reconsideration, though its rejection came with fewer than nine hours left in the legislative session.

More: *NM Political Report*

PRC Approves Plan to Replace Nuclear Power

The Public Regulation Commission last week approved a plan that calls for new solar generation to replace the capacity that will be lost when the Public Service Co. of New Mexico stops buying electricity from the Palo Verde nuclear plant in Arizona in the next three years.

PNM will lose 114 MW after its Palo Verde leases expire — one in 2023 and the other in 2024. Under the plan, the company will develop more solar energy with backup battery storage.

A proposal was filed with the PRC last April, but it took months for the commission to sign off despite requests by the utility for expedited consideration. Utility officials said that because of the delay, some contracts will have to be renegotiated and that the solar power won't be available in time to help with peak 2023 summer demands. PNM was expected to submit its plan last week for meeting demands, saying a quick decision by regulators is imperative.

More: *The Associated Press*

OHIO

Regulators Block Watchdog's Requests for Info on Fund Audit

Public Utilities Commission Attorney Examiner Gregory Price last week blocked watchdog Ohio Consumers' Counsel (OCC) from obtaining a copy of any draft audit into a $458 million charge from FirstEnergy that started in 2017 called the "Distribution Modernization Rider." The OCC also sought to depose an auditor who worked on report.

Price denied both requests, saying the facts are clear that no such draft report exists in any form, and that the question of FirstEnergy's political spending is being "thoroughly addressed" in other PUC cases. Price further said the OCC's reliance on a previous text shows its "obvious interest in investigating potential wrongdoing" as opposed to matters it "actually has jurisdiction over."

The OCC has previously obtained a text message from FirstEnergy's CEO referencing former PUCO Chairman Sam Randazzo "burning the DMR final report."

More: *Ohio Capital Journal*

TENNESSEE

MLGW Board Members Acting on Expired Terms for Months, Years

The three-year terms of all five Memphis Light, Gas & Water governing board members have been expired for at least a year-and-a-half, according to MLGW records. Michael Pohlman, the most recently appointed commissioner, saw his term expire more than 18 months ago. The other four members remain seated despite last being appointed nearly six years ago. Each of their three-year terms expired in 2019.

Issuing a single-sentence statement, Mayor Jim Strickland's office said he decided not to appoint or reappoint anyone to the board until officials closed the bidding process for seeking power suppliers that might replace TVA. Repeating language in the City Charter, MLGW's communications office said that commissioners serve "until the expiration" of their terms and "until their successors are elected and qualified," which technically allows a commissioner to serve longer than three years without a reappointment.

More: *The Institute*

TEXAS

Electric Utility Board Votes to Move Forward with Competitive Market

The Lubbock Electric Utility Board last week voted to transition Lubbock Power & Light to the competitive electric market.

Under the new plan, customers would have the ability to choose an electric plan from multiple retail providers with different pricing and contract terms. Those providers would buy and sell power while LP&L would own and maintain poles, lines and other infrastructure.

If the Lubbock City Council also approves the move during its Feb. 22 meeting, LP&L says it would be on track to enter the competitive market in late 2023.

More: *Lubbock Avalanche-Journal*

VIRGINIA

House Republicans Hit Back at Democratic Decarbonization Laws

House Republicans last week voted to overturn or delay all three Democratic decarbonization laws, although the rollbacks are likely to be halted in the Senate.

Three bills to repeal the Virginia Clean Economy Act, withdraw the state from the Regional Greenhouse Gas Initiative and delay its adoption of California vehicle emissions standards all cleared the House last week on party-line votes.

Republicans have railed against the Democratic decarbonization laws, casting them as government overreach and arguing that clean energy advances need to be driven by the free market rather than mandates.

More: *Virginia Mercury*

WEST VIRGINIA

AEP Looking for Bids to Start Solar Plant

Appalachian Power last week announced the issuance of a request for proposals (RFP) for up to 150 MW of solar energy resources with the option to include a battery-energy storage system.

AEP issued the RFP as part of the provisions of Senate Bill 5833, which was passed in 2020, to further the development of renewable energy resources and facilities for solar energy.

Project bids must be at least 50 MW in size, located in the state, and interconnected to PJM. Projects must be operational by Dec. 15, 2025, and qualify for the Federal Investment Tax Credit.

More: *Bluefield Daily Telegraph*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