# RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

ISSN 2377-8016 : Volume 2020/Issue 27 July 7, 2020

## DC Circuit Rejects FERC on Tolling Orders

*By Rich Heidorn Jr.*

Rejecting more than 50 years of precedent, the D.C. Circuit Court of Appeals ruled last week that FERC can no longer use tolling orders to delay judicial review of its rulings under the Natural Gas Act.

The 10-1 *decision* June 30 concluded that the commission's use of tolling orders to stop the 30-day clock for acting on rehearing requests improperly prevents litigants from appealing FERC rulings indefinitely even as it allows gas pipeline companies to seize property under eminent domain and begin construction (*Allegheny Defense Project, et al. v. FERC*, 17-1098).

"The commission and private certificate holders use its tolling orders to split the atom of finality," Judge Patricia A. Millett wrote for the majority. "They are not final enough for aggrieved parties to seek relief in court, but they are final enough for private pipeline companies to go to court and take private property by eminent domain. And they are final enough for the commission to greenlight construction and even operation of the pipelines. Tolling orders, in other words, render commission decisions akin to Schrödinger's cat: both final and not final at the same time.

Under Section 19a of the Natural Gas Act (15 U.S.C. § 717r(a)), "unless the commission acts upon [an] application for rehearing within 30 days after it is filed, such application may be deemed to have been denied. No proceeding to review any order of the commission shall be brought by any person unless such person shall have made application to the commission for a rehearing thereon."

FERC did not respond last Tuesday when asked whether the ruling will also end the commission's ability to use tolling orders to delay appeals of orders under the Federal Power Act.

[UPDATE: On July 2, Chairman Neil Chatter-

*Continued on page 6*

## Offshore Wind Plans Take Shape in California

### *Opposition from Coastal Residents, Fishing Industry, Navy*

*By Hudson Sangree*

A floating wind turbine off the coast of Norway | *U.S. Department of Energy*

An early-stage proposal for offshore wind in California emerged last week at a state Energy Commission workshop, which also showcased the powerful opposition that could delay or stop those plans.

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## Tx Incentive NOPR Leaves Many with Sticker Shock

*By Michael Brooks and Rich Heidorn Jr.*

FERC's proposed new approach to awarding transmission incentives drew some support but also generated much sticker shock among stakeholders, who said it would increase costs in many cases without providing additional benefits (RM20-10).

Wednesday was the deadline for comments on FERC's March Notice of Proposed Rulemaking that would, among many other things, double the adder for participating in an RTO and shift from awarding benefits based on the risks and challenges of a project to one focused on economic and reliability benefits. (See *FERC Proposes Increased Tx Incentives*.)

FERC, which gained authority to issue incentives in the Energy Policy Act of 2005, implemented its policy in Order 679 in 2006 and opened a Notice of Inquiry to reconsider the policy in 2019 (PL19-3).

| *Burns & McDonnell*

### 'But For' Projects

Alliant Energy and DTE Electric, identifying themselves as "transmission-dependent utilities," said incentives should only be available for "transmission development that is not otherwise occurring or to accomplish specific policy objectives," saying bonuses are not needed in MISO's footprint, which "has experienced robust transmission development over the last 10 years without them."

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## In this week's issue

# Panelists Probe Racial Disparities in Energy Industry

*By Amanda Durish Cook*

Industry experts last week discussed the energy industry's racial gaps and how to design more equitable energy policies that address the higher bills and bad air quality often faced by the poor.

Diana Hernandez, Columbia University assistant professor of Sociomedical Sciences at the Mailman School of Public Health, said one out of three U.S. households are "energy insecure" — paying a high proportion of their earnings on utility bills, facing disconnection notices or forced to keep their homes at unhealthy temperatures to cut costs.

African Americans and Latinos are most likely to face energy insecurity and often pay more for energy bills, Hernandez said during the June 30 panel discussion, held via Zoom and sponsored by Pecan Street, an Austin, Texas-based electricity data research organization.

Hernandez said "the legacy of segregation" means that marginalized populations live in older, less energy-efficient households and are generally not able to afford new efficient appliances, better insulation or new windows.

The University of California Berkeley's Energy Institute at Haas in June *found* that Black households have higher residential energy expenditures than white households across the nation. Researchers said Black renters pay on average $273 more per year than their white counterparts, while Black homeowners pay about $408 more per year than white homeowners.

"They're paying more, and they're benefiting less from new energy technologies," Hernandez said.

"People end up making trade-offs in quality of life for high-energy burdens," said Dana Harmon, executive director of the Texas Energy Poverty Research Institute. He said that food and clothing are the most common concessions before covering high energy bills.

Hernandez used as an example Lisa Daniels, a 68-year-old Newark, N.J., resident who died in 2018 after Public Service Electric and Gas disconnected her power, leaving her without access to her oxygen mask. Her death prompted New Jersey Gov. Phil Murphy last year to *sign* a law that bars utilities from shutting off power for 90 days after nonpayment by customers who rely on electric medical devices to survive.

Pecan Street General Counsel and CFO Fisayo Fadelu said disadvantages for communities of color are evident in cities' infrastructure investments.

"We need to acknowledge that the playing field is not even. Equal investment will not work," he said.

Fadelu said that while communities of color might not recognize energy justice as a priority, energy efficiency lowers housing costs. The clean energy sector can provide much-needed well-paying jobs, he said, but cities must be willing to invest in those communities to correct racial burdens, he said.

"Race has been and is the most dominant issue in American politics," said John Hall, director of regulatory and legislative affairs for the Environmental Defense Fund. "Because racism is such a dominant force in our society, that gives rise to systemic racism. And systemic racism is in every sector and industry."

Hall said the first step organizations usually take is enacting diversity equity and inclusion plans pertaining to hiring practices, then extending those principles to their contractors.

"Overall, the energy sector, as well as the fossil fuel industry and clean energy sector, have not enacted diversity, equity and inclusion plans," Hall said. "And as a consequence, they have not afforded communities of color the opportunity to participate."

Minority communities are more likely to be located near fossil fuel plants and bear the brunt of harmful emissions, Hall said. Employees of color are often barred from blue-collar jobs in energy production, he said, expressing concern the same trend is developing in the clean-energy sector.

"We need all Americans — not most — to make being anti-racist their business," Hall said.

MISO is one organization that recently recommitted to diverse hiring practices during its June Board of Directors meeting. (See *MISO Board Addresses Racism, Social Unrest*.) A recent follow-up *letter* from Board Chair Phyllis Currie and MISO CEO John Bear acknowledged "recent events of horrific mistreatment of the African American community."

"We view these events as indicative of even broader concerns over systemic racism that unfairly discriminates against human beings throughout this community and many other diverse communities," Currie and Bear wrote.

"We stand with the African American community," the letter continued. "It is a community in pain, and we know that to have real empathy, we must do more to listen and learn from their perspectives on systemic racism and long-term disparate treatment."

Currie and Bear vowed MISO will recruit interns from historically Black and Hispanic colleges and universities.

Pecan Street said it plans to hold additional virtual panel discussions on the energy industry's racial disparities. ■

Environmental Defense Fund Director of Regulatory and Legislative Affairs John Hall | *Pecan Street*

## FERC/Federal News

# House Dems Offer Climate Package

By Rich Heidorn Jr.

House Democrats last week offered a 547-page Climate Crisis Action *Plan*, setting a goal of making the U.S. a net-zero emitter of carbon dioxide economy-wide by 2050.

Issued as a majority report of the House Select Committee on the Climate Crisis on June 30, the plan says its proposals would reduce net U.S. greenhouse gas emissions by at least 37% below 2010 levels in 2030 and 88% below 2010 levels in 2050 and provide almost $8 trillion in climate and health benefits through 2050.

Built around 12 "pillars," including investments in infrastructure, agriculture, technology and workforce development, the plan identifies "hundreds" of recommendations for legislation. While the proposals are unlikely to advance in the current Congress, they will be central to Democrats campaigning leading into the November elections.

The committee was created in January 2019. Although its plan includes just a single explicit mention of the Green New Deal proposed by Rep. Alexandria Ocasio-Cortez (D-N.Y.) and Sen. Bernie Sanders (I-Vt.), it appears to borrow from it, calling for labor protections and posing climate actions as an economic development driver.

"Environmental justice and our vulnerable communities are at the center of the solutions we propose," committee Chair Kathy Castor (D-Fla.) said in a statement. "The health of our families and the air we breathe are at the heart of our plan. We chart the course to good-paying jobs in solar and wind energy, in manufacturing American-made electric vehicles and in strengthening communities, so they are more resilient to flooding, extreme heat, intense hurricanes and wildfires."


Rep. Kathy Castor (D-Fla.), chair of the House Select Committee on the Climate Crisis | *House Select Committee on the Climate Crisis*

The plan calls on Congress to enact carbon pricing but warns it "is not a silver bullet and should complement a suite of policies to achieve deep pollution reductions and strengthen community resilience to climate impacts." It said carbon pricing should be accompanied by policies to reduce pollution from facilities located in environmental justice communities and protect domestic industries from unfair competition from foreign competitors with lower environmental standards.

The Democrats said their proposals have been *endorsed* by more than 90 organizations, including the Natural Resources Defense Council, Environmental Defense Fund, National Wildlife Federation and the Sierra Club.

Republicans on the committee issued a *statement* chiding Speaker Nancy Pelosi (D-Calif.), saying that rather than seeking a bipartisan approach, she reversed "more than 200 years of House precedent" with rule changes to limit debate.

"Working together provides the best chance of maintaining U.S. global competitiveness and emissions-reducing leadership at home and abroad — without increasing costs on working families," the Republicans said. "Policies rooted in innovation lower the cost of energy, drive economic growth and cut emissions. Our own experience with the energy renaissance in the oil and gas sector is proof. Economic growth and energy security do not have to be sacrificed in order to improve the environment. In fact, increased production of American shale natural gas helped produce the greatest emissions reduction in history. Our increased production also checks the ambitions of countries, like Russia, that wish to use energy as a weapon."

Lisa Jacobson, president of the Business Council for Sustainable Energy (BCSE), *said* the Republicans' comments on the report "show many areas of alignment for the parties."

"While the recommendations in this report begin their path through the legislative process, BCSE urges Congress to pass the American

Energy Innovation Act, which has amassed strong bipartisan support under the leadership of Senate Energy and Natural Resources Committee Chairman Lisa Murkowski (R-Alaska) and Ranking Member Joe Manchin (D-W.Va.), as a foundational first step," Jacobson said.

Among the plan's proposals are the following:

- Create a Clean Energy Standard to achieve net-zero emissions in the electricity sector by 2040 and an Energy Efficiency Resource Standard to address rising electricity demand from electrification. The plan would extend and expand clean energy tax incentives and grant programs.
- Order FERC to develop a long-range transmission infrastructure strategy to site interstate transmission lines in high-priority corridors. "Congress also should direct FERC to remove roadblocks in power markets that slow the growth of electricity generation from clean sources," it said.
- Expedite deployment of zero-emission technologies where they are already available while setting GHG emission standards for cars, heavy-duty trucks and aviation. It would seek 100% sales of zero-emission cars by 2035 and heavy-duty trucks by 2040.
- Incentivize states and cities to adopt updated model building codes, including net-zero-emission building codes, with a goal of making all new residential and commercial buildings net-zero emissions by 2030.
- Develop new standards for water infrastructure resilience that account for more frequent and damaging floods, droughts and erosion.
- Cut methane emissions from the oil and gas sector by 65 to 70% by 2025 and 90% by 2030, compared to 2012 levels, and eliminate the routine flaring of methane. Update the Federal Power Act to ensure FERC "considers climate science and public input" in siting new natural gas infrastructure. Eliminate oil and gas industry exemptions in the Clean Air Act, Clean Water Act, and Resource Recovery and Conservation Act.
- Increase funding for federal clean energy research, development and demonstration, and reorganize the Department of Energy around a climate mission.
- Establish performance standards to reduce emissions from industrial facilities, combined with border adjustment mechanisms to address foreign goods made with higher-polluting processes.
- "Dramatically increase" federal investment in carbon-removal research and development, and improve financial incentives for direct air capture technology.
- Repeal tax breaks for large oil and gas companies, and restructure the tax code to support reaching net-zero emissions by 2050. Limit new leasing for fossil fuel extraction on public lands onshore and offshore.
- Create a Climate Adaptation Program to ensure homes, businesses and critical infrastructure can withstand the impacts of climate change. Require any post-disaster rebuilding to meet "climate-informed" standards against flood, wind and wildfire threats.
- Help farmers and ranchers adopt soil health practices to improve their resilience to extreme rainfall and drought.
- Protect and restore ocean and wetland ecosystems, forests and grasslands to sequester carbon and improve resilience to wildfires and coastal flooding. ■

FERC/Federal News

# DC Circuit Rejects FERC on Tolling Orders

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jee, a Republican, and Commissioner Richard Glick, a Democrat, issued a statement asking Congress "to consider providing FERC with a reasonable amount of additional time to act on rehearing requests involving orders under both the Natural Gas Act and the Federal Power Act."

"We believe that any such legislation should make clear that, while rehearing requests are pending, the commission should be prohibited from issuing a notice to proceed with construction and no entity should be able to begin eminent domain proceedings involving the projects addressed in the orders subject to those rehearing requests," they said.]

### Precedent Overturned

Millett said the D.C. Circuit erred since 1969 when it ruled in *California Company v. Federal Power Commission* (411 F.2d 720) that issuing a tolling order meant that FERC had "acted upon" the request under the language of the statute, and that parties must wait until the commission's review of the request is complete before seeking relief from the court.

Millett said the court may overturn precedent when it decides that a previous holding was "fundamentally flawed" or when intervening developments — such as Supreme Court decisions — have "removed or weakened the conceptual underpinnings from the prior decision."

In the 1969 ruling, the court "elevated policy concerns about 'administrative and judicial problems' over the plain statutory text" of the NGA, Millett wrote. "Of course, in so doing, that panel could not have foreseen the commission's routinization of tolling orders, the unbounded length of tolling periods or, since *California Co.* involved rate setting, the severe consequences of the tolling practice for property owners. *Stare decisis* principles do not require us to continue down the wrong path."

### 'Virtually Automatic'

Millett wrote that FERC's use of "tolling orders that do nothing more than buy itself more time to act on a rehearing application and stall judicial review has become virtually automatic."

Over the last 12 years, the commission issued tolling orders in all 39 cases in which a landowner sought rehearing in a proceeding involving natural gas pipeline construction, taking about seven months on average from tolling order to actual rehearing decision.

Between 2009 and 2017, FERC issued tolling orders in response to 99% of all the requests for rehearing of pipeline certification decisions that it received, giving itself "roughly 10 times as long as the statute allots for it to act," the court said.

For the 114 natural gas pipeline cases pending before FERC from Oct. 1, 2008, through Feb. 19, 2020, in which any party requested a rehearing, the commission authorized construction to begin before ruling on the merits of the rehearing request in 64% of the cases.

### Atlantic Sunrise

The current case arose from FERC's 2017 approval of Williams Companies' Atlantic Sunrise project, an expansion of the company's existing Transcontinental Pipeline, in which the commission took an extra nine months to act on rehearing. Transco initiated condemnation proceedings for the Atlantic Sunrise project less than two weeks after FERC granted it a

Natural gas pipeline construction | *Williams*

# FERC/Federal News

certificate of public convenience and necessity on Feb. 3, 2017.

Transco told the Pennsylvania district court that, "as to this process, the eminent domain process, the [certificate] order is final" and beyond the court's jurisdiction to review. Yet Transco and FERC told the D.C. Circuit that "the very same order was 'non-final' agency action for purposes of the homeowners' effort to obtain judicial review," Millett wrote.

Although the court dismissed FERC's motion to dismiss landowner and environmental groups' appeal of the Atlantic Sunrise order on procedural grounds, it concluded FERC acted properly in approving the project.

The homeowners and environmental groups said FERC's reliance on the precedent agreements was arbitrary and capricious because those contracts only proved demand for export capacity, not domestic use of the natural gas being transported. The court said it did not need to address the homeowners' and environmental associations' objections to the reliance on precedent agreements because the commission also relied on other evidence of domestic demand.

Millett noted that Congress gave FERC four ways to act on rehearing requests under the NGA: grant or deny rehearing or abrogate or modify its order without further hearing.

The NGA requires litigants to seek appellate review within 60 days after the commission's order on rehearing.

Even after a petition for appellate review is filed, the court said, FERC has the power to "modify or set aside" its findings and orders until the administrative record is filed in court, which is typically 40 days after the petition is served on the commission. "So in practice, even if an applicant files a petition for review immediately after a deemed denial, the commission will typically still have at least 70 days total" to act, Millett said.

### New FERC Policy

The court's ruling was foreshadowed by the judges' skepticism during oral arguments on April 27. (See *DC Circuit Skeptical of FERC Tolling Orders*.)

On June 9, FERC issued a rulemaking saying it will no longer permit gas pipeline developers to begin construction until it acts on the merits of any rehearing requests (Order 871, *RM20-15*). (See *FERC Revises Pipeline Policy on Landowner Concerns*.)

However, in taking note of FERC's action, Millett pointed out that the policy change does not prevent eminent domain proceedings from going forward while a rehearing request is pending on a certificate order.

The court said that although it generally gives agencies deference in interpreting ambiguous statutes, that "deference is available only when an agency interprets a statutory provision that Congress has charged it with administering through application of its expertise," which does not apply in this case.

To "grant" rehearing "necessarily requires at least some substantive engagement with the application," the court said.

But FERC's tolling orders qualify them as being made only "for the limited purpose" of "afford[ing] additional time for consideration of the matters raised."

"That is not a grant of rehearing of the challenged order; it is kicking the can down the road," Millett said.

### Dissent, Concurrence

Judge Karen LeCraft Henderson dissented on overturning the court's previous interpretation of tolling orders.

"Section 717r(a) has not changed since [the] Natural Gas Act was enacted in 1938," she wrote. "Overruling *California Co.* and its progeny because a majority of our court now believes those cases misconstrued Section 717r(a) renders *stare decisis* meaningless and draws the judiciary into a policymaking role that is the province of the elected branches."

Judge Thomas B. Griffith filed a concurrence saying that the court had not gone far enough to address due process concerns and that tolling orders "are just one part of the legal web that can ensnare landowners in pipeline cases."

Griffith noted that the majority opinion declines to rule on orders that "grant rehearing for the express purpose of revisiting and substantively reconsidering a prior decision" and provide "further hearing processes."

"That limitation on today's decision leaves the commission free to grant rehearing by agreeing to consider the applicant's arguments for modifying or revoking its previous action — i.e., by deciding to decide. "The commission would easily satisfy the act by setting a briefing schedule or by ordering the pipeline company to respond to the claims made in the application."

While last week's ruling "rightly jettisons the commission's signature stalling tactic," Griffith said, "it doesn't alter the fact that the commission can postpone review by granting rehearing." ■

# Tx Incentive NOPR Leaves Many with Sticker Shock

Continued from page 1

The companies said incentives should be reserved for high-risk and high-reward projects such as interregional transmission. "Blanket approval of incentives does little to drive desired behaviors; instead, such actions may encourage overbuild and add unnecessary costs to customers."

Similarly, the American Council on Renewable Energy (ACORE) said incentives should be limited to projects that prove their proposals "would not be built but for the award of the incentive."

"FERC explained it has not proposed such a 'but for' provision because Congress did not clearly direct the commission to include such a provision. However, Congress did direct FERC to incentivize new transmission capacity if it benefits customers. Awarding ratepayer funds to project applicants that would be built in the absence of an incentive are not being incentivized by the award."

A coalition of consumer and environmental groups that have opposed transmission projects — including Transource Energy's Independence Energy Connection project in PJM and Central Maine Power's New England Clean Energy Connect merchant line — said the commission seemed to ignore the comments in response to its NOI "in favor of proceeding with a predetermined agenda."

The groups said Congress' legislation authorizing incentives had a dual purpose of both ensuring reliability and reducing the cost of delivered power by reducing congestion. "As written, the statute clearly intends that the cost of incentives to consumers shall be ameliorated by reduction in their power costs. In practice, the commission's incentives policy has historically taken liberty with the stated purpose of the statute and congressional intent."

### From 'Risks and Challenges' to 'Benefits'

FERC's proposal to shift from awards based on "risks and challenges" to one based on "benefits" resulting from the project drew both support and opposition.

ACORE supported the change, saying it would help ensure deployment of energy storage as transmission as well as new technologies. "Dynamic line ratings and other technological innovations can provide quantifiable economic benefits and reduced power costs by increasing the capacity of transmission infrastructure at lower costs than new wire solutions, but these innovations are not properly compensated for their benefits under the current approach."

Among FERC's proposals was a 50-basis-point (bp) adder to projects that meet a pre-construction benefit-to-cost ratio in the top 25% of projects examined over a sample period, with another 50 basis points for projects that meet a post-construction b/c ratio in the top 10% of projects.

The commission also proposed up to 50 bp for projects that show reliability benefits through quantitative or qualitative analysis.

The R Street Institute, a free-market advocacy think tank, said that the proposed 100-point economic benefits adder, "on its face, seems absurd, as any project should pass a cost-benefit analysis prior to approval. Increasing ROE [return on equity] for something that should already be happening does not incentivize transmission projects to be more cost effective."

The American Public Power Association said the ex ante economic benefit adder "would unreasonably grant incentives based on analysis of congestion cost savings that might never materialize, and the ex post economic benefit adder rewards projects that have already been built."

APPA said any reliability incentive should be limited to the portion of the project investment that is needed to produce reliability benefits above NERC reliability standards. It also said reliability incentives should not be "based on qualitative reliability benefit claims alone."

The National Association of State Utility Consumer Advocates (NASUCA) said the change "will result in the payment of costly incentives to transmission projects likely to be built anyway, with or without incentives, and thereby serves to increase the cost of transmission projects borne by customers while providing no clear customer benefit."

"The NOPR fails to provide evidence that the incentives are needed," said Paul N. Cicio, president of the Industrial Energy Consumers of America, which filed comments jointly with 37 other groups under the name "American Manufacturers."

"Transmission projects that are needed are getting built," Cicio said. "Every dollar of financial incentive would be passed onto us, the consumer ratepayer. Given today's economic uncertainty, this is a terrible time to consider increasing electricity rates on manufacturers, our nation's job creators."

### Advanced Tech

The Working for Advanced Transmission Technologies (WATT) Coalition and Advanced Energy Economy submitted joint comments noting that FERC has never implemented the requirement in EPAct 2005 that it encourage the deployment of new transmission technologies.

"For all the hundreds, if not thousands, of proceedings on energy market design, significant efficiencies lie untapped in the operation of the physical network hardware," they said.

The groups proposed "a modest, targeted incentive to support the adoption of advanced transmission technologies like dynamic line ratings, topology optimization, and similar tools that increase the capacity and efficiency of the existing grid." They said their proposal would fulfill FERC's statutory obligations.

**"For all the hundreds, if not thousands, of proceedings on energy market design, significant efficiencies lie untapped in the operation of the physical network hardware."**

—The Working for Advanced Transmission Technologies (WATT) Coalition and Advanced Energy Economy

R Street said, "The number of adders that are available to transmission projects is already quite generous and should be examined before handing out more customer dollars for these ventures." It called FERC's proposal to replace the current limit on incentives with a 250-basis-point cap on total ROE adders "a good start," but it said "there needs to be a stop to the layering of incentives, as it is not attracting new and innovative technologies."

# FERC/Federal News

It also said the proposed 100-point adder for new technologies is "not enough to retool the transmission system."

"FERC needs to be ... setting up a regulatory paradigm that can usher in new innovations and technology," R Street said. "Any enhancements to the electric grid need to include more than just ROE incentives; for new technology to be pushed forward, FERC must look to other models to properly incentivize innovation."

The Energy Storage Association said storage should be eligible for incentives because of its ability to "enhance the flexibility and efficient use" of existing transmission facilities.

"Returns for transmission owners are largely based on allowed rates of return from capital investment. Even if less expensive investments can attain operational capabilities that achieve equal or superior outcomes as a conventional transmission solution, transmission owners would face a reduction in return by undertaking the less expensive investment," ESA said. "For example, fast-acting energy storage can provide rapid injections pre- or post-contingency events to maintain reliability of the transmission system and reduce congestion on key lines or interfaces. Use of storage in this way can be far less expensive than building redundant transmission conductors, which is the standard way to handle transmission contingencies."

## Doubling RTO Adder

FERC's proposal to double the adder for participation in an RTO from 50 to 100 basis points attracted much opposition, with some critics saying it should be eliminated altogether.

"What action or decision is influenced by an incentive that rewards a continued payment years after the joining of the RTO?" the Union of Concerned Scientists asked, noting that most RTOs and ISOs already had most of their current members in 2005. "Simply rewarding continued membership seems to provide additional revenue to member utilities without commensurate increase in benefits to consumers," it said.

"No evidence has been put forth demonstrating that the existing benefits of RTO membership are insufficient incentive for TOs to join and remain in RTOs absent an ROE adder," the Maryland Public Service Commission said. "The existing 50-bps RTO ROE adder as it stands ... provides no incremental benefit to customers. Therefore ... the commission's proposed 100-bps RTO ROE adder [is] simply wholly untenable."

"The commission's proposal to double the RTO participation incentive ROE adder in perpetuity will only add costs and provide no discernable benefits to customers who have paid very expensive RTO participation adder for many years," NASUCA said.

The proposal also drew fire from the California Public Utilities Commission. (See *CPUC Calls FERC Tx Incentive Plan 'Atrocious.'*)

But the PJM Transmission Owners sector said the increased incentive is justified because "the risks to transmission owners of RTO membership are significant, such as giving up control of their system and assets to join and participate in RTOs."

The TOs said, however, that incentives are not sufficient, saying the commission must also "ensure a stable and equitable policy on transmission owners' 'base' return on equity."

## Need for Transmission Planning Reform

The Electricity Consumers Resource Council, filing with the American Chemistry Council and the American Forest & Paper Association, said they understand the need for new transmission but disagree with that incentives "should be — or can be — a key driver of that development."

"The root cause of underdevelopment, to the extent underdevelopment is pervasive and problematic, is a set of institutional barriers that should be addressed head-on instead of tangentially, expensively and ineffectively via transmission incentives policy," the groups said. "The appropriate tools available to federal policymakers to address barriers to development include improvements to transmission planning and cost allocation, as well as new legislation from Congress if it chooses to address any additional federal role in transmission siting."

ACORE also called for changes to transmission planning procedures. "The incorporation of grid optimization and advanced technologies in the planning process, more standard and broad cost allocation, and increased inter-RTO transfer capability will lead to a more robust and efficient electric grid," it said. "Where possible within its authority, FERC should enhance efforts to streamline transmission siting and enable construction of necessary transmission lines."

The group cited research from the National Renewable Energy Laboratory that increased transmission development at regional seams could save consumers more than $47 billion and return more than $2.50 for every dollar invested.

ITC also called for a broader review, saying for incentives to proceed "it is necessary to revisit other commission policies and potentially abandon them (e.g., competitive solicitation processes) or reform them (e.g., transmission planning)."

The company said Order 1000's competitive solicitation processes are "in direct conflict with the commission's incentives policy" by encouraging TOs to adopt least-cost projects to address transmission needs.

Instead, it said the commission should use a risk-sharing approach similar to that of the New York Public Service Commission for public policy transmission, which gives the developer 20% of cost savings below the targeted cost with the remaining 80% going to consumers. Developers are responsible for 80% of any cost overruns.

UCS noted that the NOPR does not include any incentives for interregional transmission projects.

"Amongst the topics under review in this process, the insufficient attention and lack of incentives for interregional transmission stands out," the group said. "The commission should acknowledge in this rulemaking that there is a problem when the borders of the ISOs/RTOs create gaps in market-based transfers of energy, increase costs due to congestion, and introduce obstacles and risks to the planning, evaluation and ultimate construction of interregional transmission."

## Eliminate Transco Adder

ITC Holdings said FERC's proposal to eliminate incentives for standalone transmission companies (transcos) "is premature and based on flawed assumptions."

"The last decade has been characterized by steady economic growth in tandem with a transformation in the energy sector once thought unimaginable, thus creating an environment that has allowed transcos and vertically integrated utilities alike to make significant investments in transmission infrastructure," ITC said. "However, the real measure of a transco's value is better captured in more challenging economic conditions when vertically integrated utilities are required to make difficult choices between investments in generation, distribution and transmission. Indeed, when one looks at the period from 2000 to 2010 — a period that includes the last major recession — transcos far outpaced vertically integrated utilities in terms of transmission investments." ■

## CAISO/West News

# Governor Signs PG&E 'Plan B' Takeover Bill

### *Utility Says Necessary Chapter 11 Financing Obtained*

*By Hudson Sangree*

Pacific Gas and Electric said it had completed its bankruptcy restructuring Wednesday, one day after California Gov. Gavin Newsom signed a bill allowing the state to take over the utility if it fails egregiously over time to obey the Public Utilities Commission's rules.

Those rules, imposed as a condition of the commission's decision to accept PG&E's bankruptcy plan in May, required the utility to submit to enhanced oversight and escalating enforcement for safety failures. Repeated and uncorrected problems could let the commission appoint a third-party monitor followed by a receiver, and eventually to rescind PG&E's license to operate as the monopoly utility for most of Central and Northern California.

If that happens, the newly enacted *Senate Bill 350* authorizes the state to seize PG&E through eminent domain and transfer its operations and assets to a nonprofit public benefit corporation called Golden State Energy, created by the legislature and governor.

"The purpose of this division is to ensure that if Pacific Gas and Electric Co. fails to emerge from bankruptcy as a transformed utility, then Golden State Energy is duly empowered to serve in that critical role," the new law says. "It is the intent of the legislature that Golden State Energy act pursuant to this division only in the event that a transformed utility does not emerge from the bankruptcy or the transformed utility fails to meet its duty to provide safe, reliable and affordable energy services."

Gov. Gavin Newsom | © *RTO Insider*

Some critics have contended the CPUC's six-step process of punishing PG&E would take so long that a takeover won't happen. Dozens of public speakers urged the commission to yank PG&E's license immediately prior to its approval of the utility's reorganization plan May 28.

"We need a public utility," one that's not motivated by profits to forgo safety upgrades and maintenance, San Francisco Bay Area resident Charlotte Quinn told commissioners.

Newsom said in a statement June 30, however, that his signing of SB 350 means there will be "no more business as usual for PG&E."

"As we head into wildfire season amid a pandemic, Californians need to have confidence that their utility is focused on customer safety, preventing wildfire[s] … and making critical safety upgrades," the governor said. "SB 350 marks a critical step in the transformation of PG&E into a utility that is accountable to those it serves."

The measure authorizes the state to sell bonds to finance the purchase of PG&E. It cleared the State Senate on June 29 and went to Newsom for his signature.

Bill author Sen. Jerry Hill (D) has called the measure a "plan B" if PG&E doesn't undergo the safety transformation it has promised. (See *Plan B for PG&E Takeover Moves Forward*.)

"As much as we push forward with that change, we must also be prepared to step in should the company not meet its obligations or commitments in the future," Hill told the State Assembly's Utilities and Energy Committee last month. "SB 350 is our preparation. I hope it's unnecessary and that it's never triggered, but we owe this preparation to the residents of San Bruno and Santa Rosa and Napa and Butte County and Paradise."

Those communities were devastated by PG&E-caused catastrophes in the past decade.

The Camp Fire, the state's deadliest and most destructive wildland blaze, wiped out most of the town of Paradise on Nov. 8, 2018, killing 85 residents and destroying more than 14,000 homes. The wine country fires of October 2017 ravaged the city of Santa Rosa and large areas of Napa and Sonoma counties. A gas pipeline explosion in September 2010 killed eight people and destroyed part of a residential neighborhood in San Bruno, a San Francisco suburb.

An estimated $30 billion in liabilities for the fires of 2017 and 2018 caused PG&E to seek bankruptcy protection in January 2019.

### 'One Step Closer to Getting Paid'

PG&E said Wednesday it had emerged from that bankruptcy after nearly 18 months by obtaining the debt-and-equity financing it needed to fund $25.5 billion in settlements with fire victims, government agencies, insurance companies and the hedge funds that bought up billions of dollars in insurance subrogation claims.

U.S. Bankruptcy Judge Dennis Montali approved PG&E's Chapter 11 plan on June 20, less than a day after it pleaded guilty to 84 charges of involuntary manslaughter in the Camp Fire. (See *PG&E Sentenced; Bankruptcy Plan Approved*.)

"Today's announcement is significant for PG&E and for the many wildfire victims who are now one step closer to getting paid," acting CEO Bill Smith said in a news release. Smith replaced former CEO Bill Johnson, who retired June 30.

"Compensating these victims fairly and quickly has been our primary goal throughout these proceedings, and I am glad to say that today we funded the fire victim trust for their benefit," Smith said.

PG&E plans to fund the victims' trust with $6.85 billion in cash in three installments through 2022 and with stock shares equal to a 22% stake in the utility, the largest electric provider in North America.

The company also said it had seated a mostly new 14-member board of directors and paid its $5 billion contribution to the state's wildfire insurance fund, created under last year's Assembly Bill 1054. (See *PG&E Names New Board of Directors*.)

Under the legal doctrine of "inverse condemnation," California holds utilities strictly liable for fires sparked by their equipment. The $21 billion fund, to be paid for equally by ratepayers and utilities, provides financial protection against devastating blazes going forward. ■

## CAISO/West News

# Offshore Wind Plans Take Shape in California

### *Opposition from Coastal Residents, Fishing Industry, Navy*

*Continued from page 1*

"The goal is that we find a path forward that allows us to potentially utilize this renewable energy resource in a way" that allays the concerns of the fishing industry, the military and others that might object, CEC Commissioner Karen Douglas said.

Under Senate Bill 100, retail load-serving entities must provide 100% clean energy by 2045. Though expensive and technologically challenging, floating deep-water turbines anchored off California's coast could provide gigawatts of renewable electricity.

Developers and offshore wind advocates pointed to the economic benefits the East Coast hopes to reap from projects in its shallower waters.

Brandon Burke, the policy and outreach director of the Business Network for Offshore Wind, cited plans in New Jersey and Virginia to invest of hundreds of millions of dollars in offshore infrastructure. New Jersey is planning to build a "*windport*" to serve OSW projects in the Mid-Atlantic region, and Dominion Energy recently announced it would build a turbine installation vessel as part of its planned 5,000 MW of offshore wind. (See *Dominion Energy Earnings Impacted by Weather, Not COVID-19*.)

These are "truly massive infrastructure investments that will drive job growth across the economic spectrum," Burke said. With 40 million Americans unemployed by the COVID-19 pandemic, offshore wind development is a chance to grow a new industry in California, he said.

"It's a once-in-a-generation economic investment and recovery opportunity," he said.

### A 6% Ocean Area

Despite the economic and environmental benefits, offshore wind in California is far from reality, experts said.

The areas where wind turbines could be placed off the California coast are relatively small, said Jean Thurston-Keller, task force coordinator with the U.S. Interior Department's Bureau of Ocean Energy Management, which controls the siting of offshore wind projects in federal waters.

State waters extend to 3 nautical miles offshore, where federal jurisdiction starts, reaching to the edge of the U.S.' exclusive economic zone at 200 nautical miles offshore.

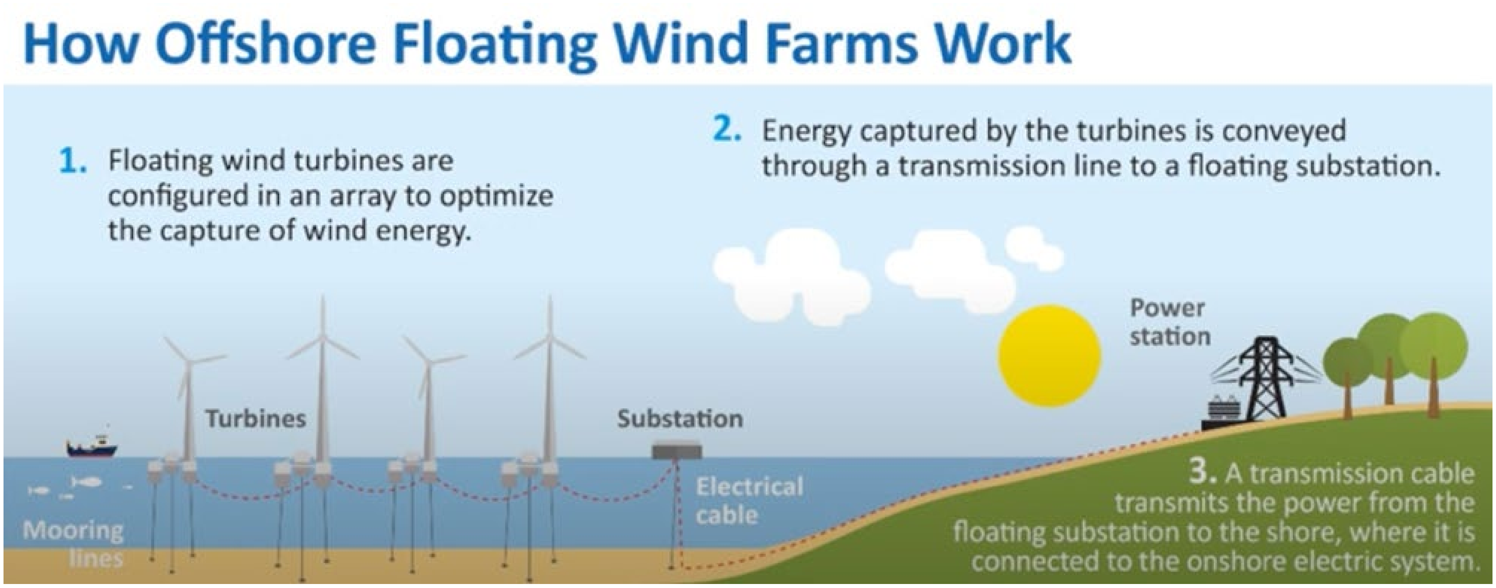
"Offshore California, this encompasses about 215,000 square miles," Thurston-Keller said in her *presentation*. "For BOEM's planning, this is where we start. Offshore wind though cannot be sited just anywhere. There are certain technical constraints that have to be considered."

Of the 215,000 square miles of federally controlled ocean area, only about 6% meets the requirements for wind farms, Thurston-Keller said. The 900-foot-tall floating turbines envisioned for the coast will need wind speeds of at least 7 meters per second and could anchor in a maximum depth of 1,100 meters, she said.

Most of offshore California is deeper, and large areas have insufficient wind speeds. In addition, vast swaths of the coast are protected as National Marine Sanctuaries, which cannot be developed, she noted.

After taking those factors into account, BOEM identified three areas — termed "calls" — where 1,000-MW wind farms might be built. Two are off California's Central Coast; the third is along the state's North Coast near Eureka and Crescent City.

Wednesday's workshop primarily dealt with the Central Coast areas. One site is near Morro Bay, Calif. The other is close to Diablo Canyon, where Pacific Gas and Electric operates the state's last nuclear generating station, which is set to retire starting in 2024.




A video showed workshop participants how offshore floating wind farms would work near the coast of California. | *Bureau of Ocean Energy Management*

Though the areas are generally suitable for offshore wind, many concerns remain, Thurston-Keller said. Planners have yet to account for underwater telecommunications cables, commercial marine traffic corridors, fishing areas and environmental issues, she said.

Under former Gov. Jerry Brown, the state and BOEM formed a task force in 2018 to begin addressing stakeholder concerns early in the process and established a data portal called the *offshore wind energy gateway*, where the public could review the information used in decision-making, Thurston-Keller said.

BOEM initiated its leasing process for its California calls in late 2018, she said, but even if a lease were granted, a developer couldn't start construction until it completed a site assessment that could take up to five years, she said.

"What does the seabed look like?" Thurston-Keller said. "Are there any hazards? Shipwrecks? Areas on the seabed that are sensitive? What frequency are avian and marine mammals occurring in the area?"

### Defense Department Concerns

The U.S. Defense Department has said wind turbines off the Central Coast could interfere with its operations. The Navy, Marines and Air Force have a large presence in Central and Southern California, regularly conducting training exercises and missile testing, among other activities.

Steve Chung, who oversees "encroachment" programs for the U.S. Navy, echoed those sentiments at Wednesday's meeting. But he said renewable energy projects that don't impede military operations might be acceptable.

"The Department of Defense is committed to working collaboratively with the state of California, BOEM, agency representatives and interested stakeholders to explore the possibilities of offshore wind that avoids adverse impacts to our military operations on testing and training requirements," Chung said.

The department's objections have led to consideration of new sites to the north and south of the current Morro Bay call and closer to shore.

### 'Bait and Switch'

Tom Hafer, president of the Morro Bay Commercial Fishermen's Organization, called the newest offshore wind proposals a "bait and switch." When employees of offshore developer Castle Wind started talking to the fishermen several years ago, they described a project with 100 wind turbines that would be 32 miles offshore. (Castle Wind still describes its project with those parameters on its *website*.)

Now BOEM is talking about putting turbines 15 to 20 miles offshore because of Navy concerns, Hafer noted.

"So, everything has changed," he said. "Bait and switch, it's called. We agreed to something and that's not going to happen anymore, so we're a little concerned about this."

He said the fishing industry stands to be harmed most by the turbines noise and electrical currents.

"This is going to screw up fishing. This is going to change the migratory habits of a lot of fish out there — albacore, salmon, black cod. Who knows what these are going to do?

"You need to talk to the fishermen — the Central Coast fishermen," he said. "We're the ones that are going to be most greatly impacted from this thing, and it kind of appears to us that you guys really don't give a ---- about fishing because you rarely talk about it.

"It's more important than this viewshed thing," he added.

The visual impact of giant wind turbines off California's scenic Central Coast is another potential pitfall.

Unsightly oil rigs have dotted sections of the coast in Southern and Central California for decades, but many areas remain relatively pristine.

Kerry O'Toole, land and resources program manager with Hearst Corp., said planners should have considered the view of the turbines from Hearst Castle, which sits on a mountain top at 1,600 feet above sea level. The heirs of publishing magnate William Randolph Hearst conveyed Hearst Castle to the state, and its conservation easements include viewshed protections, O'Toole said.

More than 600,000 people visited the castle, part of the state park system, in 2019, she said. Windmills would mar the "visitor experience," including the long and winding drive from the visitor center to the castle, she said.

Coastal residents also don't like the idea of windmills marring their view. In written comments, resident Laura Vaughn said, "Leave Big Sur alone. It's beautifully untouched by your energy-grubby fingers. The public should have a say!"

Bill Douros, with the National Oceanic and Atmospheric Administration's Office of National Marine Sanctuaries, cautioned stakeholders about getting worked up too soon. The planning process will take years, with multiple state and federal agencies involved, he said.

"This is so far away from any kind of final action," Douros said. "It's really Stage 0, or Stage 0.1, in a long process." ■


The California Energy Commission is considering areas on the North and Central coasts for offshore wind farms. | *California Energy Commission*

## CAISO/West News

# CAISO Briefs Western EIM on Hybrid Resources

### *July 29 Deadline for Tariff Revisions*

*By Hudson Sangree*


PG&E's VacaDixon solar-and-battery array was the first hybrid resource to participate in CAISO's market starting in 2016. | © *RTO Insider*

With less than a month to go before a July 29 deadline for completing tariff changes, CAISO on June 30 presented the Western Energy Imbalance Market's Governing Body with its plan for accommodating hybrid generation and storage resources.

The EIM Governing Body plays an advisory role to CAISO's Board of Governors on its hybrid resources *initiative*. With thousands of megawatts in the interconnection queue, the ISO is trying to move swiftly to develop policies to let the combined resources take part in its market, but it has concerns too.

CAISO said it adopted the tight timeline because it is trying bring more resources online in anticipation of potential shortfalls during the next three summers and to make up for the impending retirement of aging natural gas plants.

The California Public Utilities Commission required load-serving entities under its jurisdiction to procure 3,300 MW of capacity by 2023. In response, LSEs proposed integrating some hybrid resources into the market as soon as this fall. CAISO must complete its work by the end of July to allow FERC 90 days to approve tariff changes before the resources go live, the ISO said.

"This is a quick one because these things are coming online really soon, and we need to make sure we have the policy around it," CAISO CEO Steve Berberich told the Governing Body.

However, he urged the body members not to be too hasty in making any recommendations

Solar panels at PG&E's VacaDixon facility | © *RTO Insider*

that could undermine the ISO's ability to control the grid. For instance, hybrid co-located resources can operate as a single unit for dispatch purposes or be separated into battery and generation components to be dispatched separately.

Some stakeholders have urged the single-unit approach. Berberich asked for patience.

"There's a whole lot of uncertainty and debate," he said. "Keep in mind we have policy, and we have to operate the grid. And operating the grid with separate [scheduling coordinator] IDs on these things, we think, probably gives us more flexibility, but we're not certain of it.

"We need some experience in operating these things" before locking in policies that could prove detrimental, he said.

The Governing Body members said they generally supported the recommendations of CAISO staff. They agreed to take the matter under advisement and provide feedback to the ISO board at an upcoming meeting.

"I'm all for additional capacity we can get for the system," said John Prescott, who was elected by fellow members June 30 as the new chair of the Governing Body. Prescott took over from Carl Linvill in a position that rotates among the body's five members annually.

"As you know, that's kind of the No. 1 issue we really face in the system today, and it's a shame that we don't grab all this capacity now," Prescott said. "But I also hear from the experts saying that, 'You know, you got a controllability issue, and you need to think through this before you just kind of open the gates and create a problem.'"

Some stakeholders feel the process is rushed, CAISO staff said. But EIM Body Member Anita Decker, who was named vice chair, said she hoped CAISO would act "with some aggressiveness" to resolve stakeholder concerns and bring resources online.

The CAISO board is planning to take up the issue at its meetings in July, with final draft tariff language due July 29.

The integration of hybrid resources is expected to be a major issue for CAISO and other organized markets, as battery storage paired with renewables plays an ever greater role.

"The ISO anticipates the quantity of mixed-fuel resources will increase significantly in the coming years," CAISO staff wrote in their second revised *straw proposal* on hybrid resources in April. "Today, there is relatively little interconnected to the ISO grid; however, the interconnection queue includes more than 24,000 MW of mixed-fuel projects, including nearly 20,000 MW of storage. This represents roughly half of all generation in the interconnection queue currently."

Other RTOs and ISOs are dealing with similar circumstances, and FERC has called a technical conference for July 23 to discuss the issue. (See *FERC, RTOs Need to Set Hybrid Rules, Experts Say* and *FERC Sets Tech Conference on Hybrid Resources*.) ■

# Texas Public Utility Commission Briefs

### Commission OKs New Generation Recovery Rule

The Texas Public Utility Commission last week approved a new *rule* that allows utilities operating solely outside the ERCOT region to apply for a generation-cost recovery rider (GCRR) for capital investments in individual generation facilities (*55031*).

The rule applies primarily to El Paso Electric, Entergy Texas, Southwestern Electric Power Co. and Xcel Energy's Southwestern Public Service. It stems from a bill passed (*HB 1397*) in last year's state legislature.

PUC Chair DeAnn Walker, pointing to the abundance of renewable facilities already installed and coming online, modified the rule in a *memo* before the July 2 open meeting to clarify that a utility may include "more than one discrete generation facility" in the rider. Utilities will be allowed to amend their GCRRs to request inclusion of additional generators.

"I feel like where we are with our future generation, most are going to be smaller projects, where you may need to have more than one included in the rider," Walker told her fellow commissioners.

The commission agreed that if the rule is not working, they can always revisit the issue. Walker said the PUC's earnings-monitoring process would allow them to determine whether any utilities were taking advantage of the rule.

Walker was the only commissioner present in the PUC's meeting room. Commissioners Arthur D'Andrea and Shelly Botkin both called in from remote locations.


Texas PUC has granted Lower Colorado River Authority a CCN for a Hill Country transmission project. | © *RTO Insider*

### PUC Extends Customer Relief Program

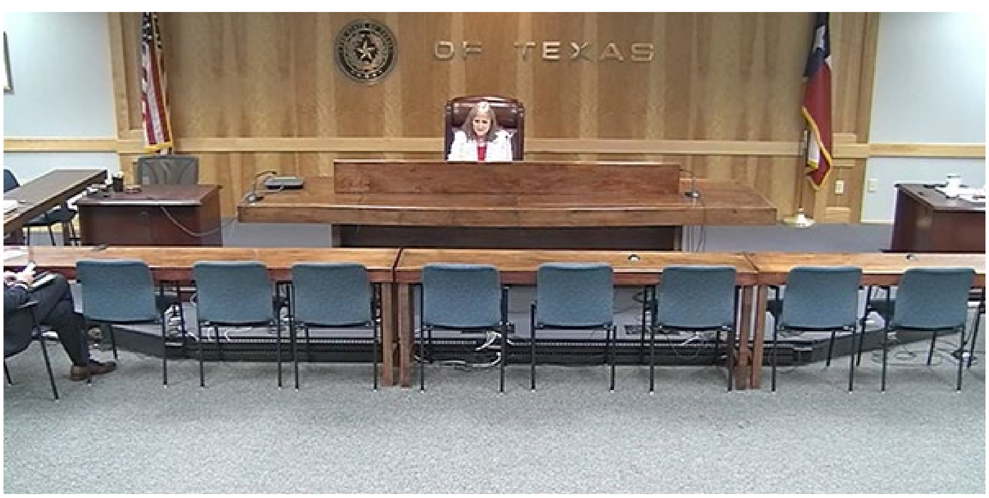
The commissioners agreed to extend the state's Electricity Relief Program from July 17 to Aug. 31, citing Gov. Greg Abbott's decision to curtail certain economic activities in the face of rising coronavirus diagnoses and hospitalizations. An order will be drafted for the commission's approval during its July 16 open meeting.

The PUC created the program in March to help retail providers' unemployed customers by shielding them from disconnections for nonpayment and offering bill payment assistance.

"While we certainly wish we could snap our fingers and make this virus go away, it's clearly with us for the long haul and we need to reflect that in our decisions," Walker said.

The state reported a record 8,258 COVID-19 confirmed cases on July 4, bringing its total to 195,239. A record 8,181 Texans were hospitalized on Sunday. The state has reported 2,637 deaths.

The program is funded by a rider charge applied to customer bills within the ERCOT region.




PUC Chair DeAnn Walker, the sole commissioner present, leads July 2's open meeting.

### Entergy, LCRA Get CCNs

In other actions, the PUC:

- *Granted* Entergy Texas a certificate of convenience and necessity (CCN) to build, own and operate a 230-kV line and substation north of Houston that is needed to accommodate future load growth. Entergy has reached a settlement with all intervenors on a 9-mile route that is projected to cost $34.1 million. The substation is expected to cost an additional $23.3 million (*49715*).
- *Approved* Lower Colorado River Authority's request for a CCN for a new substation and a 138-kV line connecting the facility with the grid in the Texas Hill Country north of San Antonio. The 22.5-mile project, costing an estimated $64.3 million, is needed to address congestion and voltage issues, LCRA said (*49523*). ■

*— Tom Kleckner*

# Developers Seek 1-Mile Spacing for Vineyard Wind

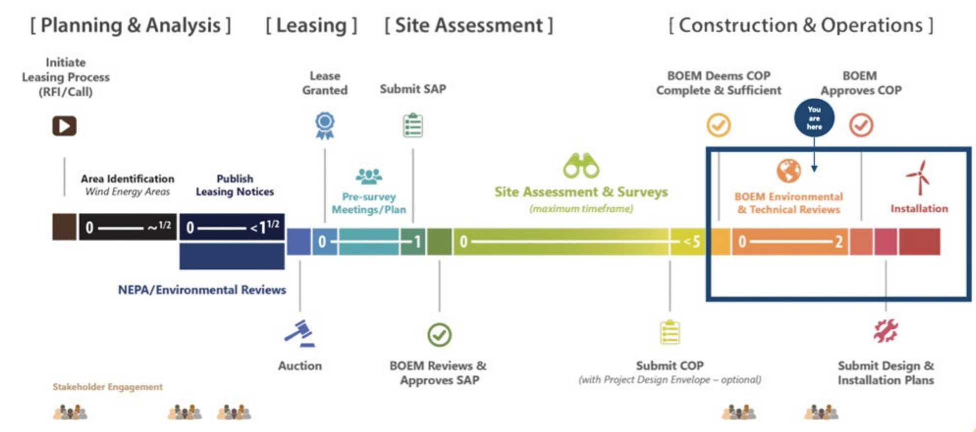
## *BOEM SEIS Includes 4-Mile Proposal*

*By Michael Kuser*

Stakeholders at a virtual public hearing on Thursday praised the Bureau of Ocean Energy Management for working through the pandemic and urged the agency to approve the 800-MW Vineyard Wind offshore wind project along with the 1-nautical-mile turbine spacing advocated by developers and recommended by the U.S. Coast Guard.

"I'd like to go on record in supporting the 1-mile distancing between towers," said Brad Lima, recently retired as chief academic officer of the Massachusetts Maritime Academy. "There was one statement in the [May 14] Coast Guard *report* that stood out: 'Anything that can be done to reduce traffic scenarios is a prudent decision.' ... It's quite evident based on the number of companies which have won leases for the Atlantic Coast sites that offshore wind is where power generation wants to be."

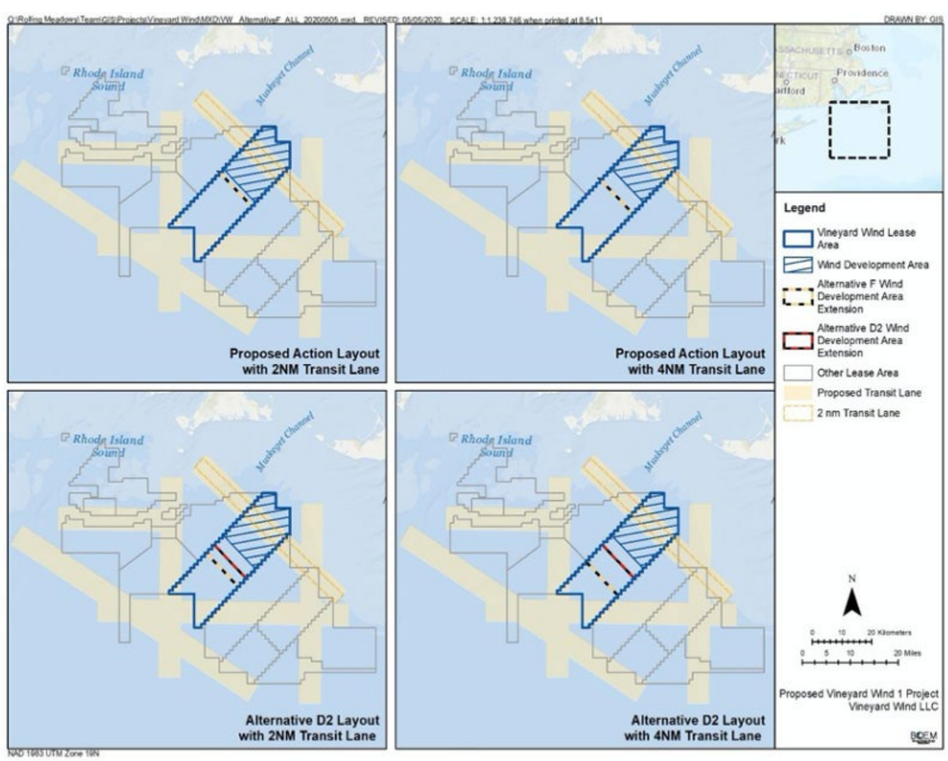
BOEM's supplemental environmental impact statement (*SEIS*) for the Vineyard Wind project, released June 9, included a proposal by the Responsible Offshore Development Association (RODA), a fishing industry group, calling for six "transit lanes" at least 4 nautical miles wide for




Vineyard Wind process progression | *BOEM*

a projected 22 GW of projects from the coasts of New England to Virginia. (See *BOEM Issues Revised EIS for Vineyard Wind*.)

The proposed transit corridor would provide a path for vessels traveling from New Bedford, Mass., and other southern New England ports to fishing grounds in Georges Bank, east of Cape Cod. Only one of the lanes intersects the Vineyard Wind 1 wind development area in federal waters south of Massachusetts.




Alternative layouts as proposed by the Responsible Offshore Development Alliance | *BOEM*

The report also reflects changes to the Vineyard project since the draft EIS: replacing 696-feet-tall, 10-MW turbines with 837-feet-tall, 14-MW turbines. The SEIS found that the cumulative effect of the 22 GW of projects could have major impacts on navigation and vessel traffic, commercial fisheries, and military and national security uses.

### Cumulative Impacts

"Global climate change presents a serious threat to the commonwealth's environment, residents, communities and economy," said Lisa Engler, director of the Massachusetts Office of Coastal Zone Management (CZM). "Gov. [Charlie] Baker has expressed the need for action. The magnitude of the impacts from climate change requires all of us to put politics aside and act together quickly and decisively.

"We still have the ability to check the severity of future impacts by aggressively reducing greenhouse gas emissions and adapting to the changes," Engler said. "The cumulative analysis included in the SEIS ensures that potential impacts beyond this individual project are evaluated."

Engler said the state's review, which included the Department of Environmental Protection, Energy Facilities Siting Board, Environmental Policy Act Office, Department of Public Utilities and the CZM, is complete.

The total project capacity still remains at 800 MW, and a change to the turbine capacity would not result in a change to the footprint or to the 8-MW minimum turbine capacity, said BOEM environmental coordinator Jennifer Bucatari, who presented the agency's *summary*

# ISO-NE News

of the SEIS. The project will comprise up to 100 wind turbines.

Vineyard Wind also submitted changes expanding the onshore substation, with a total area of ground disturbance of 7.7 acres, which is 1.8 acres greater than the area analyzed in the draft EIS, she said.

As for the various transit lane proposals and the turbine locations they would displace, "under the current cumulative scenario, displacement of all these turbine locations is not feasible, and therefore the addition of all six transit lanes would lead to the elimination of some of the turbines that could have occurred within these lanes," Bucatari said.

## Competitor Concerns

David Hardy, COO of Ørsted North America Offshore, praised BOEM's work on the supplemental EIS. "It is no small feat to forecast the myriad impacts the development of a new ocean-based resource will have on the human and natural environment, both positive and negative," he said.

Ørsted has been awarded more than 2,900 MW of offtake rights, with the states of Connecticut, Maryland, New Jersey, New York, Rhode Island and Virginia having all awarded their first offshore projects to the company.

Hardy said Ørsted "strongly" supported the developers' consensus proposal of 1-nautical-mile turbine spacing, with an east-west layout for simpler navigation.

He said RODA's proposed 4-mile spacing "would result in the loss of over 50 wind turbine locations from our current three projects: South Fork, Revolution Wind and Sunrise Wind. ... This equates to a nearly 25% loss in the total wind turbine locations for our state" power purchase agreements.

The SEIS should reflect a more favorable rating of offshore wind as a domestic economic development engine consistent with ongoing and planned investments, Hardy said, noting Ørsted is planning to spend $15 billion over the next decade in the U.S.

"For many of the cumulative impact parameters considered in the SEIS, BOEM chose not to incorporate widely accepted or legally mandated mitigation strategies; thus the bottom-line impact of the 22-GW buildout must be considered a worst-case scenario and not as representative of as-constructed impacts," Hardy said.

Where BOEM comes out on the Vineyard project will likely determine the fate of offshore wind in the whole country, said Joe Martens, director of the New York Offshore Wind Alliance and former commissioner of the New York Department of Environmental Conservation.

"A plain reading of the SEIS could lead to the conclusion that if the Vineyard Wind project is not advanced, other projects in various stages in the pipeline inevitably will," Martens said. "I don't think this is the case. ... The [Vineyard] developers have gone above and beyond the extensive federal, state and local requirements for offshore wind."

The Vineyard project is in effect a "litmus test" for the industry, he said, urging its approval on both environmental and economic grounds. "All eyes are on this project."

## Communities Supportive

The project has been thoroughly vetted by all the "top notch" environmental groups and should be approved to provide more renewable energy for the state, said Eileen Mathieu, board member of Sustainable Marblehead, a volunteer community organization in the town of Marblehead, Mass.

"In Marblehead, our municipal light department ... is eager to be able to purchase reasonably priced electricity from renewable sources," Mathieu said. "However, local resources are very constrained, so that right now we only have 12% renewable energy in our portfolio and 26% nuclear."

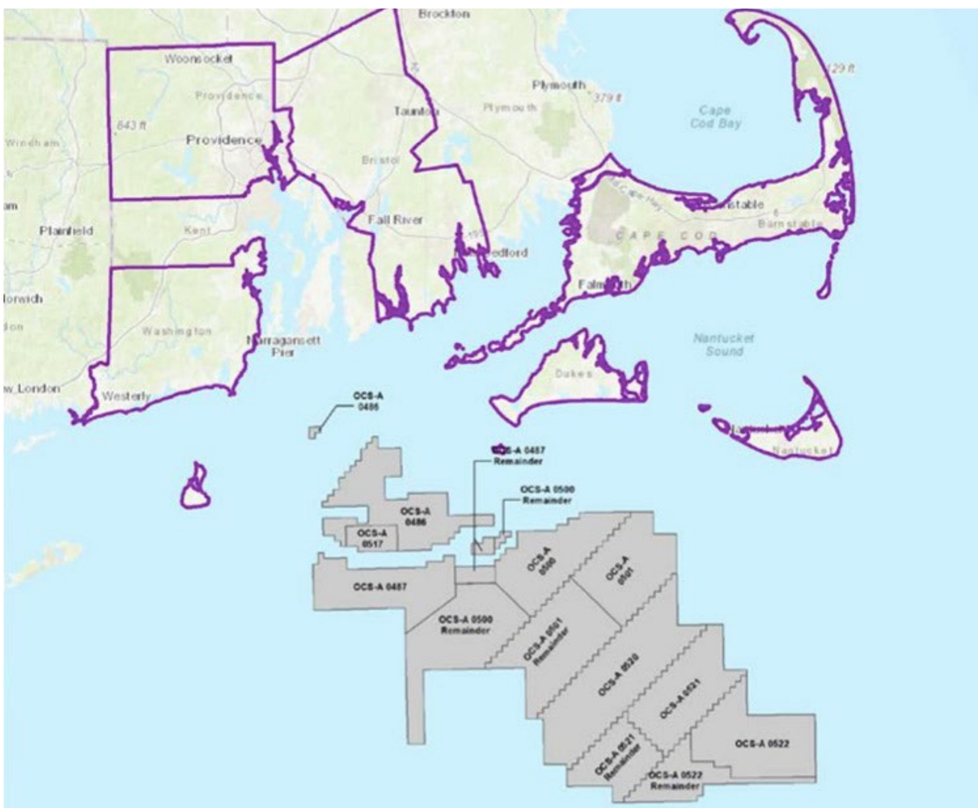
Marblehead buys its power through the Massachusetts Municipal Wholesale Electric Co., which "needs wind options to provide its 22 municipal light plant members, and currently it has none," Mathieu said.

"We strongly support this project as the first large-scale OSW project in the region," said Kai Salem, policy advocate for the Green Energy Consumers Alliance.

Fred Hopps of Beverly, Mass., founder of the town's clean energy advisory committee — and a former resident of Copenhagen, Denmark — gave "a thousand thanks to the Danes for practically single-handedly keeping offshore wind energy alive."

BOEM will hold two more web-based public hearings on the SEIS for Vineyard Wind, on July 7 and 9, with the public comment period open through July 27 on a dedicated *website*. The agency expects to publish its final EIS in November and to issue a final decision in December.

Vineyard Wind is a joint venture between Copenhagen Infrastructure Partners and Avangrid Renewables. ■




Economic and environmental justice geographic analysis area for the Vineyard Wind project | *BOEM*

## ISO-NE News

# FERC Opens Proceeding on ISO-NE New-entrant Rules

By Michael Kuser

FERC last week established a paper hearing to explore the justness and reasonableness of ISO-NE's new-entrant rules for its Forward Capacity Market (EL14-7-002, EL15-23-002, EL20-54).

The June 30 decision came on remand from the D.C. Circuit Court of Appeals, which ruled in February 2018 that the commission failed to adequately explain why it approved capacity market rules for ISO-NE in 2014 like those it had rejected in PJM for suppressing prices. (See DC Circuit Orders FERC to Review ISO-NE Auction Orders.)

The court ruling granted petitions for review by Exelon and the New England Power Generators Association on rules allowing new suppliers to lock in their first-year clearing prices for six additional years while requiring them to offer at $0 in years 2 through 7 (15-1071).

"In light of the time that has passed since the NEPGA and Exelon complaints were filed and the changes to the ISO-NE Forward Capacity Market during that time, we believe it is appropriate to provide parties an opportunity to refresh the record on which we will address the issues raised in the court's remand," the commission said.

It noted that capacity prices have been trending downward in ISO-NE auctions and that it has approved several changes to the FCM, including Tariff revisions to implement the Competitive Auctions with Sponsored Policy Resources construct, it said. (See ISO-NE Capacity Prices Hit Record Low.)

The commission issued a set of questions to guide the paper hearing and said it was instituting a new Section 206 proceeding "because certain of these questions may not have been directly presented in the original NEPGA and Exelon complaints."

### Relevant Questions

At the inception of the FCM in 2006, the commission accepted Tariff provisions that allowed a new resource to lock in for five years the capacity price that it receives in the first Forward Capacity Auction in which it participates. Under that rule, a new resource receives that initial clearing price for the four subsequent annual auctions (the lock-in period), even if the actual clearing price for those subsequent auctions is higher or lower.

Exelon and NEPGA had complained that the commission's approval of the rules was at odds with its 2009 ruling rejecting a similar construct in PJM. The D.C. Circuit agreed, saying that FERC had "failed to square its decision with its past precedent."

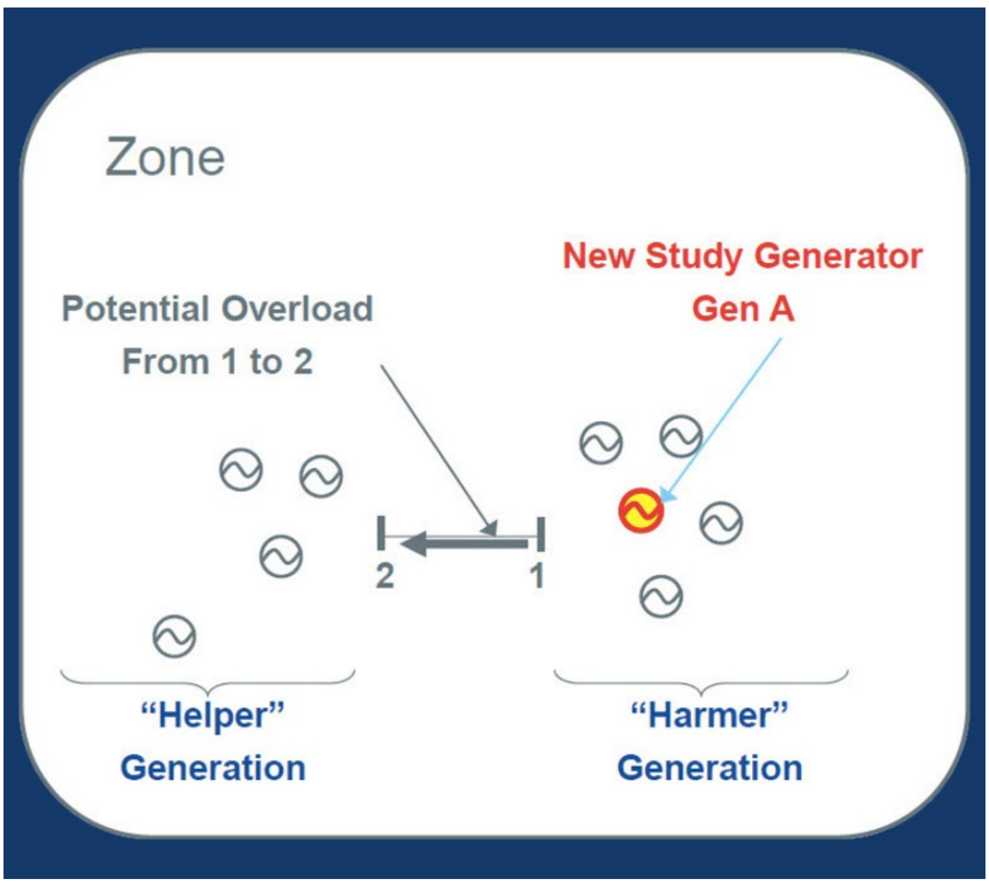
In last week's order, FERC said it was concerned that any potential effects that the current new-entrant rules could have on the FCM clearing price may outweigh the certainty and other benefits that the commission considered when approving those provisions.

To evaluate the need for the price lock in its entirety, the paper hearing will first pose the following questions:

- How many resources have taken advantage of the price lock to date?
- Is a price lock still needed to incent new entry in ISO-NE?
- Does the price lock lead to unreasonable price suppression in the entry year?
- Does the price lock with the zero-price offer rule result in unreasonable price suppression in years 2-7?
- Is the price lock unduly discriminatory?
- If the price lock is retained, should the term be shortened and, if so, what would be a just and reasonable term?

Second, to evaluate retaining the price lock and adding an offer floor, the commission will ask how an offer floor would be implemented, whether it would require significant market redesign, and what the timeline would be for implementation.

Third, to evaluate whether to impose an alternative replacement rate, the commission seeks to address whether there are alternative approaches to the current price lock that would be sufficient to incent new entry, and how these alternative approaches would address any concerns related to unreasonable price suppression, undue discriminatory or preferential treatment. ■




Before accepting a new generating resource for its FCM, ISO-NE tests to ensure they do not cause overloads that cannot be fixed in time for the capacity commitment period. | *ISO-NE*

## ISO-NE News

# NEPOOL Markets/Reliability Committee Briefs

### Mapping Future Grid Study

Concluding "less is more," stakeholders looking to shape a planned grid transition study for New England opted Wednesday to create a smaller, more manageable committee to oversee the hiring of consultants and conduct of the analysis.

A joint meeting of the New England Power Pool Markets and Reliability committees opened with a *memo* from the officers of both committees, which noted the sentiment of several stakeholders favoring adapting modeling and assumptions from existing studies or those currently underway rather than starting from scratch, as was discussed at the joint meeting in May. (See *NEPOOL Markets/Reliability Committee Briefs: May 27, 2020*.)

"We also need to consider how detailed workflow will be managed between meetings. For example, some have suggested hiring an independent consultant to manage these efforts, designating a small representative working group of individuals willing to commit time towards managing study details, or similar," the memo said.

It included a draft template for collecting proposals of scenario assumptions. The final template will be distributed soon; responses are due to the MC *secretary* by July 17 for the Aug. 4 joint meeting, at which a presentation will be made on a grid study underway now by Energy Futures Initiative and E3.

### Eversource Offers Preliminary Results

Vandan Divatia of Eversource Energy *presented* his company's Grid of the Future study methodology and preliminary results, with modeling and analysis performed by London Economics International.

"I agree that this approach — with a 10- to 15-person smaller group … with representatives from each sector participating and then bringing back information for alignment — makes a lot of sense," Divatia said.

[Note: Although NEPOOL rules prohibit quoting speakers at meetings, those quoted in this article approved their remarks afterward to clarify their presentations.]

Economy-wide $CO_2$ emissions reduction will result in major changes to the electricity industry. Increased demand from electrification of heating and transportation will shift the peak from summer to winter, leading to deployment of energy storage resources and new technologies, as well as market support for reliability services, transmission expansion and operational infrastructure, the report said.

The study said that electric vehicles could account for 48% of emission reductions from 2020 to 2040, which led Ben Griffiths of the Massachusetts attorney general's office to ask if the study authors had "a sense of how much decarbonization will then be occurring from the power sector, or from converting gas heating customers to electric heat pumps, or something like that?"

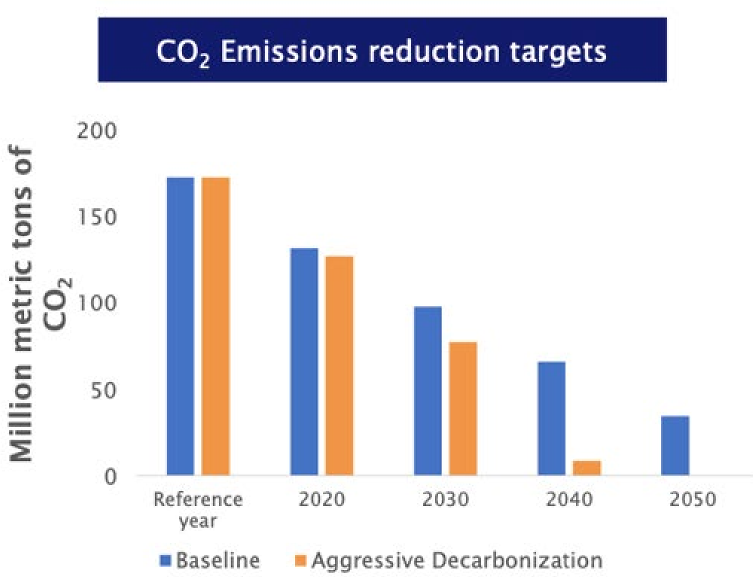
Divatia said Eversource and LEI had assessed what would be required from each sector to achieve near total decarbonization by 2040 but had not included that level of detail in the study.

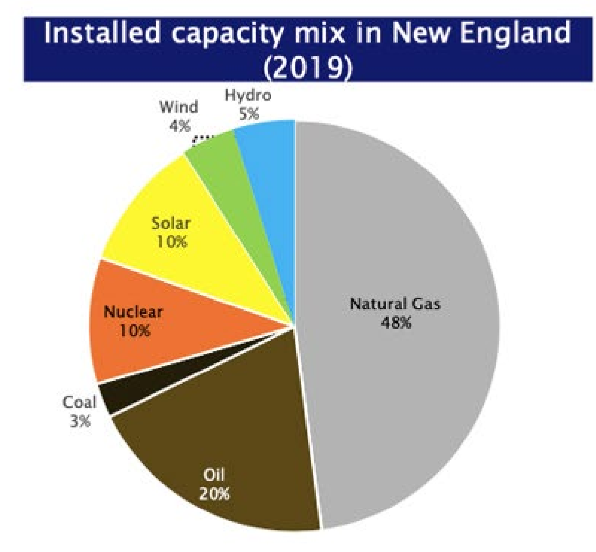
"Transportation accounts for 42% of the carbon footprint of New England, and the electric sector accounts for only 14%, so if we want to go from here to there in a strategic fashion, the approach we've taken is that each sector needs to do its job," Divatia said.

On how the study planners got from emissions to modeling, Julia Frayer of LEI said, "We made a starting assumption that we wanted to look beyond just the power sector, so we could actually reflect the intentions of policymakers, which is to decarbonize the economy."

Because it is a long-duration study going out to 2050, the analysts incorporated a capacity expansion model with two objective function goals, she said. "One was to achieve the carbon emissions reductions, and the second criterion was to meet electricity demand reliably."

The capacity expansion model built out a




Source: ISO-NE Regional Energy Outlook 2020, LEI analysis

The Grid of the Future Study is designed to understand changes in all sectors of the economy and their impact on the grid. | *ISO-NE, LEI*

# ISO-NE News

plan for resources that could meet the 2050 carbon emissions goals. "Through backwards induction, we could back into interim goals that we've created for 2040 and 2030 ... for transformation of the electricity sector from the demand side and the supply side," Frayer said.

## National Grid 2020 Economic Study Details

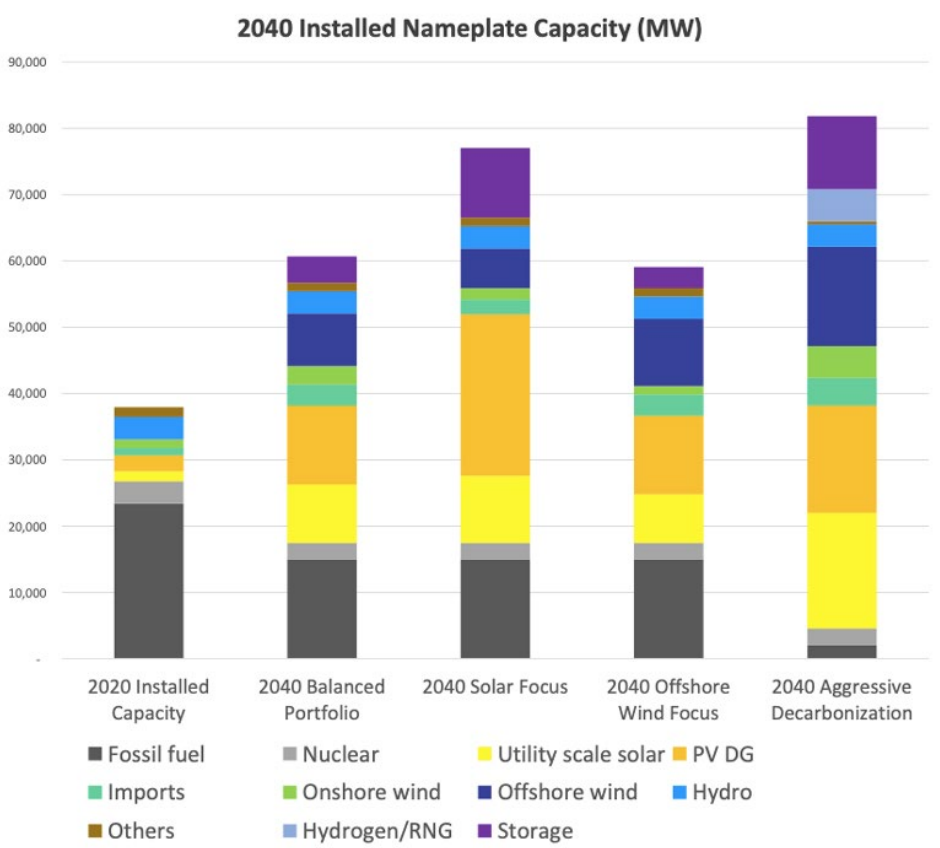
Engineer Julia Grasse of National Grid *presented* the firm's 2020 Economic Study request, including a pathway emphasizing the role of exchange with Québec, which previous studies indicated may be utilized as a balancing resource in a future system with a large amount of intermittent renewables. (See "2020 Economic Study Scope, Assumptions," *ISO-NE Planning Advisory Committee Briefs: May 20, 2020*.)

Two recent studies in particular drove the company's request, the first being a 2019 offshore wind *study* by the New England States Committee on Electricity (NESCOE) that showed high levels of renewable resource spillage, and the second being MIT's 2020 *study* on deep decarbonization of the Northeastern U.S., which demonstrated that bidirectional transmission with Québec complements high intermittent resource mixes in New England.

Specifically, National Grid wants to evaluate the role that large-scale "dispatchable reservoir" hydro in the north could have in meeting the state goals, the presentation said.

ISO-NE will analyze three scenarios: the base case, with varied offshore wind, solar and thermal retirements; bidirectional transmission capability, with use of existing and new interties to explore up to 3,600 MW of export capability to Québec; and varied amounts of in-region battery storage, the lowest at 2,000 MW as used in the NESCOE study.

Stakeholders will discuss the study at the Planning Advisory Committee meeting July 22, with further refined RTO assumptions. The draft results expected, and sensitivities identified will come in the third quarter, with sensitivity results and draft ancillary services results in the fourth before the draft and final reports in Q1 2021.




| LEI

## Bay State Net-zero Overview

Participants also heard an overview of a Massachusetts decarbonization study to guide the state's effort to achieve net-zero greenhouse gas emissions reductions by 2050, an initiative that boasts its own *website*.

"Overall, our approach is backcasting, which is an exercise to understand what is needed today to get to where we want to be in 2050," Massachusetts Undersecretary for Climate Change David Ismay said. (See "Modeling the Future," *Overheard at 166th NE Electricity Roundtable*.)

The state's net-zero policy requires at least an 85% reduction in emissions below 1990 levels by 2050, plus carbon sequestration to make neutral the remaining emissions, he said.

"We're modeling the mega-region of the Northeast from New York to Maine, together with Québec and New Brunswick ... for a 90% emissions reduction from 1990 levels, which we think is valuable, since there are different dynamics when you go past an 80% reduction," Ismay said.

The study will entail more than a half-dozen complete scenarios, including detailed total cost analyses, and the state will work through NESCOE this summer to share full results with colleagues in all New England states ahead of a planned full public release in the fall, he said.

When asked if Massachusetts was planning to request an economic study by ISO-NE based on the analysis, Ismay said, "We will be bringing a lot of data to ISO-NE and NEPOOL for this discussion, rather than asking ISO-NE to do it themselves."

"At some point soon, the grid operator will need to get into the details at least at this level, though I'm not exactly sure how or when that's going to happen," he added.

## Stakeholder Perspectives

Brian Forshaw of Energy Market Advisors proposed an analytical *framework* for the future grid study on behalf of the Connecticut Municipal Electric Energy Cooperative (CMEEC).

ISO-NE currently lacks a Forward Capacity Market pricing model for planning studies, which can often make it more challenging to interpret study results, the presentation said.

CMEEC recommended development of a capacity optimization tool to reflect the current market construct and develop estimates of what capacity market prices would be under various scenarios, he said.

# ISO-NE News

Caitlin Marquis of Advanced Energy Economy presented *input* that asked whether the markets, as designed today, meet future needs in a technology-neutral way. She said that AEE views analysis of the transition to the future and discussion of potential market reforms as being just as important as the planned operational and reliability assessment.

With respect to the reliability analysis, "we're really most interested in understanding what grid services and operational tools are needed to address reliability gaps," Marquis said. "We see the resources of the future as requiring more flexibility, see the heightened importance of resource availability and not just adequacy, and certainly a different range of reliability services."

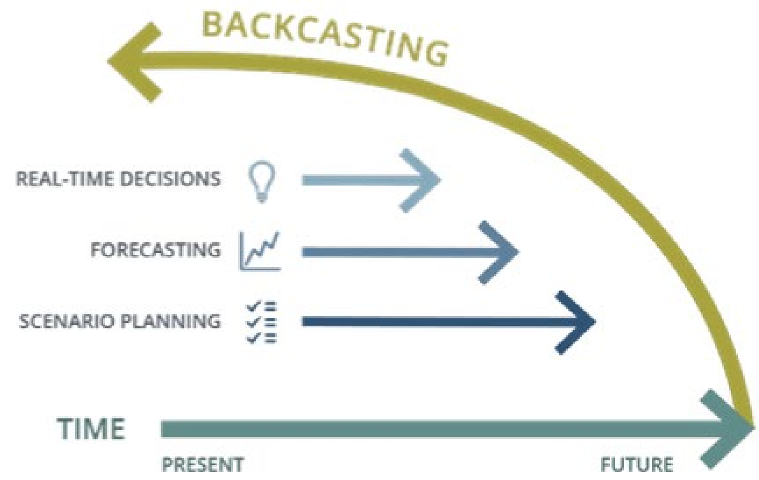
One side of that assessment should be looking at whether markets are equipped to make full use of demand flexibility and demand-side resource participation, she said.

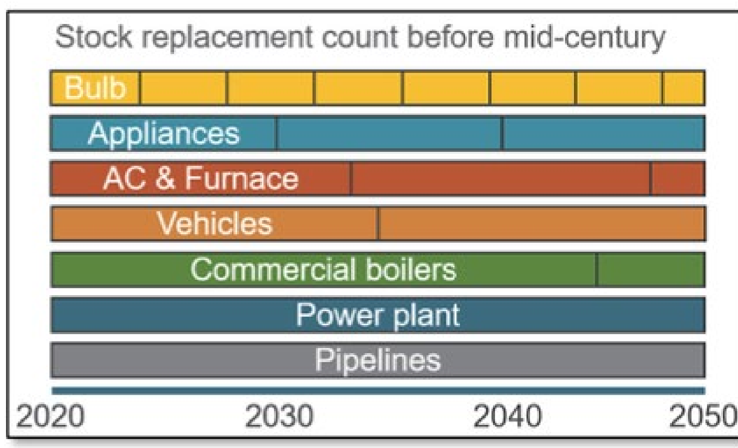
Peter Fuller of Autumn Lane Energy presented further *thoughts* on the evolving grid study, made with the endorsement of NEPOOL members NRG Energy and Sunrun.

Today's markets do not include a value for carbon commensurate with the value that state policies imply for it, the presentation said. It also asks where system inertia and stability will come from in a system with more distributed, digital and inverter-based resources.

The presentation asked what other aspects of system operability and reliability are being taken for granted that will need to be explicitly valued in the future and said the sponsors hope to address that and other questions at the August joint meeting. ■

*— Michael Kuser*




The Massachusetts 2050 Roadmap study is using "bottom up" backcasting to explore a range of compliant scenarios and taking into account the varying replacement timelines for appliances, vehicles and infrastructure. | *Mass EEA*

# Stakeholders Split on Potential MISO RA Requirements

*By Amanda Durish Cook*

Stakeholders appear torn over whether MISO should proceed with a potentially controversial effort to develop reliability guidelines that could establish uniform resource adequacy criteria across its footprint, stepping into territory currently reserved for the states.

With its own studies showing an emerging wintertime loss-of-load risk, MISO has recently signaled that it may define its own system reliability criteria, possibly as part of its ongoing resource availability and need project.

"The transition to a different portfolio is happening, and happening quickly, I would say," Jessica Harrison, MISO director of research and development, said during a virtual stakeholder workshop June 30.

Harrison said MISO faces interconnection of a growing number of gigawatts from intermittent resources.

"There's a lot more management that has to happen throughout the year," she said. "There are strong indicators of change, and there are strong indicators that we need to do something."

While MISO has yet to define what would be the objectives and outcomes of such an effort, officials have said load-serving entities need the RTO to provide more direction on reliability in order to make resource investment decisions.

"People are asking us now, 'I have a billion-dollar investment. It's a decade-long asset. Will we need this?'" Executive Vice President of Market and Grid Strategy Richard Doying said at MISO's Board of Directors meeting last month.

"We need MISO to provide forward-looking guidance," Xcel Energy's Kari Hassler said. She said the MISO footprint should operate according to a single set of reliability criteria instead of several disjointed sets established by state regulators.

But other stakeholders said such a requirement would tread on states' jurisdiction over resource adequacy and their prerogative to create their own resource mixes.

Mississippi Public Service Commission consultant Bill Booth said Mississippi is only looking to MISO to provide annual local clearing requirements and planning reserve margins, which the state adopts only when it agrees with the RTO's assessment.

"I don't think Mississippi is looking to MISO for anything beyond those," Booth said.

But Gabel Associates' Travis Stewart said inaction by MISO could result in some states developing insufficient resource mixes and enjoying "free ridership," where one state relies on ratepayers in other states for resource adequacy.

"This is very much the dynamic in some loads," he said, adding that if loads decide to go 100% solar, they should include reliability mechanisms.

Stewart said MISO can help by developing market rules that send economic signals that incent jurisdictions to build or retire reliably. ■

Jessica Harrison, MISO | © *RTO Insider*

## MISO News

# CapX2050 Prompts MISO Focus on Midwest Tx

*By Amanda Durish Cook*

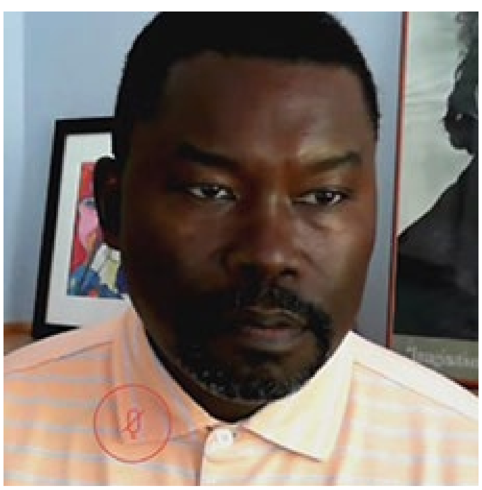
MISO says it will conduct a more thorough study of transmission capacity needs in the Upper Midwest after being approached by the utilities behind the independent CapX2050 planning study.

The move means the RTO will expand and protract an existing transmission study it's carrying out under its 2020 Transmission Plan (MTEP 20). Executive Director of System Planning and Competitive Transmission Aubrey Johnson announced the study expansion at a virtual June 26 planning meeting of the Minnesota Public Utilities Commission, where CapX2050 and Clean Grid Alliance representatives urged commissioners to make new transmission a priority.

Johnson said the RTO made the call to expand the profile of its current North Region Economic Transfer informational study in response to a May *letter* from — and discussions with — the 10 Minnesota utilities that produced CapX2050.

MISO's study focuses on the increasing non-thermal limitations of the Minnesota-Wisconsin export interface, which is experiencing bottlenecks as renewable-rich northwestern portions of the RTO's footprint seek to transport power to load centers in the Upper Midwest. (See *MWEX Study Could Elicit New Tx Planning for MISO*.)

Johnson said work on an expanded study will begin later this year. Unlike the original informational study that served to explore non-thermal constraint modeling and is unlikely to result in a project, the expanded phase of the study could result in a project recommendation in the fall of 2021. MISO has never before included non-thermal constraints in its planning modeling.



MISO's Aubrey Johnson appears at a June 26 virtual planning meeting of the the Minnesota PUC | *Minnesota PUC*

The CapX2050 group has been requesting for a few months that MISO explore more long-range transmission planning. (See *CapX2050 Calls for More Tx, Dispatchability in Midwest*.)

"We're already seeing resource-choice limits … from a lack of transmission capacity," Clean Grid Alliance Executive Director Beth Soholt told the Minnesota commission. "Whether we're going to have that resource choice directly bears on whether we have the transmission to do that in a timely manner."

Soholt invoked the findings in MISO's own 2020 *Interconnection Queue Outlook Report*, which concluded that the RTO needs billions of dollars in new transmission to accommodate proposed generation projects in the MISO West planning region, which includes Minnesota, Iowa, parts of the Dakotas and western Wisconsin.

"Recent interconnection studies for new generation resources in MISO's West subregion have indicated the need for network upgrades exceeding $3 billion to accommodate the initial queue volume, and a similar trend is expected to occur in other areas with high wind and solar potential, including MISO's Central and South subregions," the RTO wrote.

### Meeting New Needs

Great River Energy Chief Vice President and Transmission Officer Priti Patel said that while MISO's planning processes guarantee reliability projects are routinely built, the RTO puts little emphasis on planning for states and utilities to meet decarbonization and renewable generation targets.

"But what we asked ourselves is, 'Are those planning processes producing efficient longer-term projects that accommodate this wholesale grid change?'" she said. "What we see is the system is changing faster than the processes can keep up.

"We are unified on the need to act and the need to act now," Patel said of the CapX2050 utilities.

Clean Grid Alliance's Natalie McIntire agreed that MISO transmission planning is simply not

| © *RTO Insider*

keeping up to accommodate utilities' decarbonization goals.

McIntire also said near-term fixes such as using dynamic line ratings and net-zero interconnections — which allow a wind generator and gas-peaking resource to split use of an interconnection site — could help free up some capacity to keep fleet transformation uninterrupted while new transmission is built.

Minnesota PUC Commissioner Matt Schuerger, who also serves as president of the Organization of MISO States, said the RTO's transmission line ratings are overly conservative, inconsistent and not transparently formed.

"Let's get some consistent, transparent line ratings," he said. "We're not fully utilizing the transmission that ratepayers have paid for."

In the meantime, MISO has made no indication that it's preparing to embark on another long-term transmission package like 2011's Multi-Value Project (MVP) portfolio.

Speaking at MISO's virtual June Board Week, Vice President of System Planning and Chief Compliance Officer Jennifer Curran observed that there was a "fair amount of agreement" in 2011 that the MVP was necessary to facilitate state renewable portfolio standards and attract investment in wind generation. Now, however, opinions are mixed among the stakeholder community, she said.

This time around, new transmission seems to be driven by "consumer preference rather than state laws," making beneficial long-range transmission more difficult to pin down, Curran said. ■

MISO News

# FERC Orders More Detail in Affected Systems Compliance

*By Amanda Durish Cook, Rich Heidorn Jr. and Tom Kleckner*

MISO, PJM and SPP are within a hair's breadth of meeting FERC's transparency requirements around affected-system studies, but both their joint and individual filings on seams issues still need fine-tuning, the commission ruled in a series of orders last week.

The commission last September ruled that the three RTOs' joint operating agreements do not provide enough clarity on how they handle the study of generator interconnections along their seams. (See *FERC Denies Rehearing on Affected System Order*.)

FERC's June 30 orders repeated that theme, directing the RTOs in their joint compliance filings to provide clearer descriptions of how they analyze each other's systems during respective interconnection studies (*ER20-942*, *ER20-940*). The commission found both the MISO-PJM and MISO-SPP joint operating agreements lack indexes that point interconnection customers to business practice manuals that explain the circumstances under which the RTOs will perform an affected-system analysis under an energy resource interconnection service (ERIS) or a network resource interconnection service (NRIS) modeling standard.

FERC gave the RTOs 60 days to add references to the rulesets.

The commission approved other aspects of the seams filings, including details on how the RTOs determine the queue priority of projects and select the ERIS or NRIS modeling standard, as well as how they exchange affected-system information and determine study criteria.

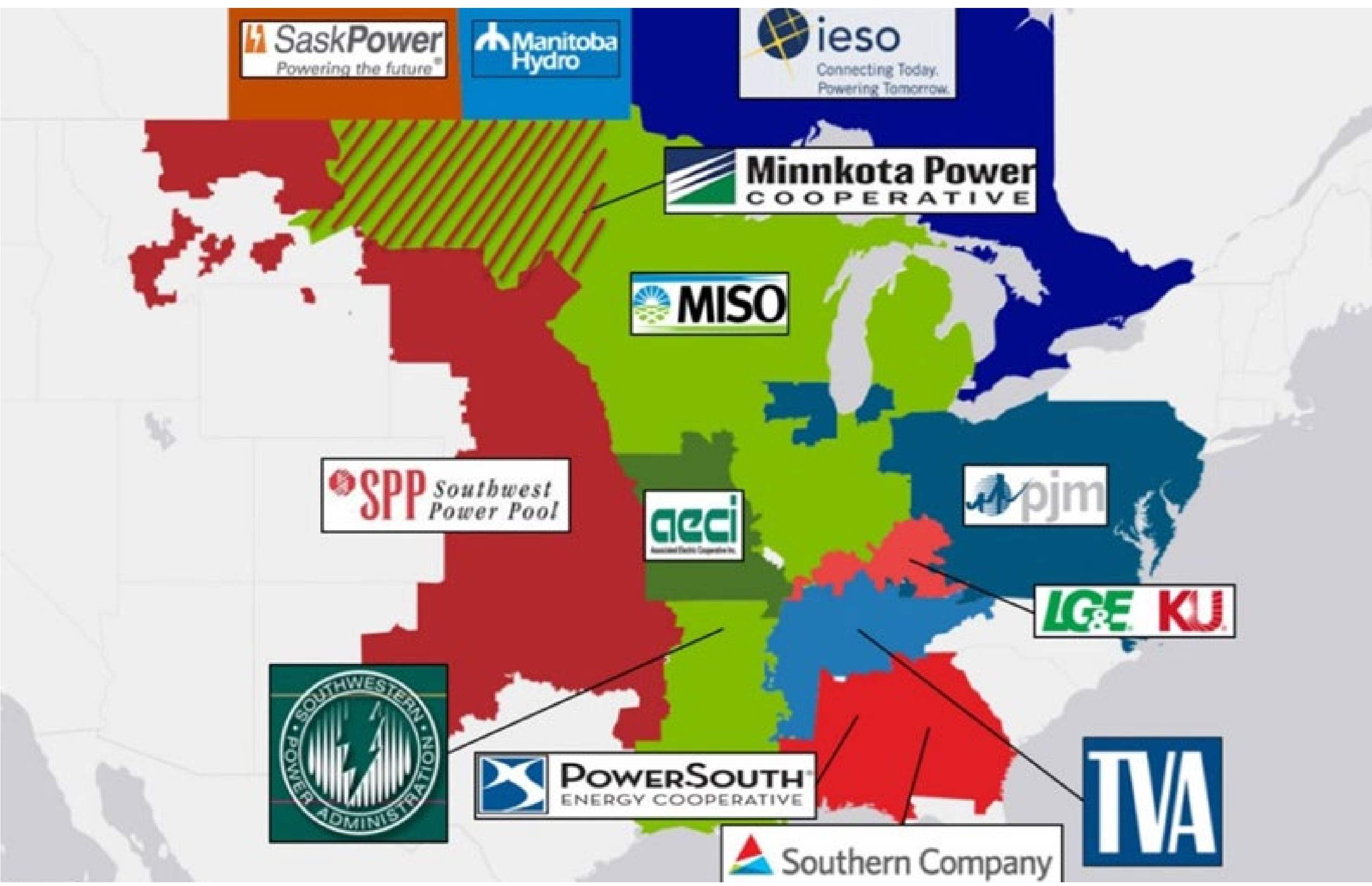
## Another Compliance Filing for SPP

The commission found SPP's proposed revisions partially complied with its 2019 order and directed the RTO to submit a further compliance filing within 60 days. FERC said the RTO's "Guidelines for the SPP GIP Process and Business Practices" document was not sufficiently detailed, as it lacked the specific section number containing the ERIS and NRIS modeling information (*ER20-945*).

## PJM in Partial Compliance

FERC said PJM had complied with the commission's directive to detail in its Tariff the time allowed interconnection customers to review affected-system study results and said the 30-day period is consistent with the time given to the RTO's interconnection customers for reviewing system impact and facility studies.

But it ordered the RTO to make another compliance filing within 60 days, saying it had failed to include where in its manuals or other documents interconnection customers can find details of the modeling PJM uses in studies of ERIS and NRIS requests on its own system (*ER20-939*). ■




MISO seams neighbors | *MISO*

## NYISO News

# NYISO Q1 Energy Prices Hit 11-Year Low

*By Michael Kuser*

NYISO energy prices sank to 11-year lows during the first quarter, ranging from $15 to $35/MWh, stakeholders heard last week.

"This is the lowest quarterly average level in more than a decade, so it's pretty exceptional," Pallas LeeVanSchaick of Potomac Economics said as he presented the Market Monitoring Unit's State of the Market report for the first quarter to the Installed Capacity/Market Issues Working Group on June 30.

Natural gas prices also dropped to their lowest quarterly average since 2009, along with electricity loads, LeeVanSchaick said.

"That was really attributable to a combination of factors, including mild weather conditions, the growth in energy efficiency and behind-the-meter solar, as well as in March we saw the effects of the COVID-19 pandemic, which many of you have heard about reducing load 8 to 9%," he said.

### Congestion Patterns and Revenues

Lower load levels and natural gas prices led to relatively low levels of transmission congestion, supplemental commitment for reliability and imports from PJM, he said.

While congestion was generally mild, the pattern was typical, with the most significant congestion observed on the Central-East interface, which accounted for about 60% of the day-ahead congestion revenues in the first quarter, LeeVanSchaick said. The pattern is typical because gas spreads tend to be largest between western and eastern New York; however, the difference dropped from 32% in the first quarter last year to only 11% in the same period this year, he said.

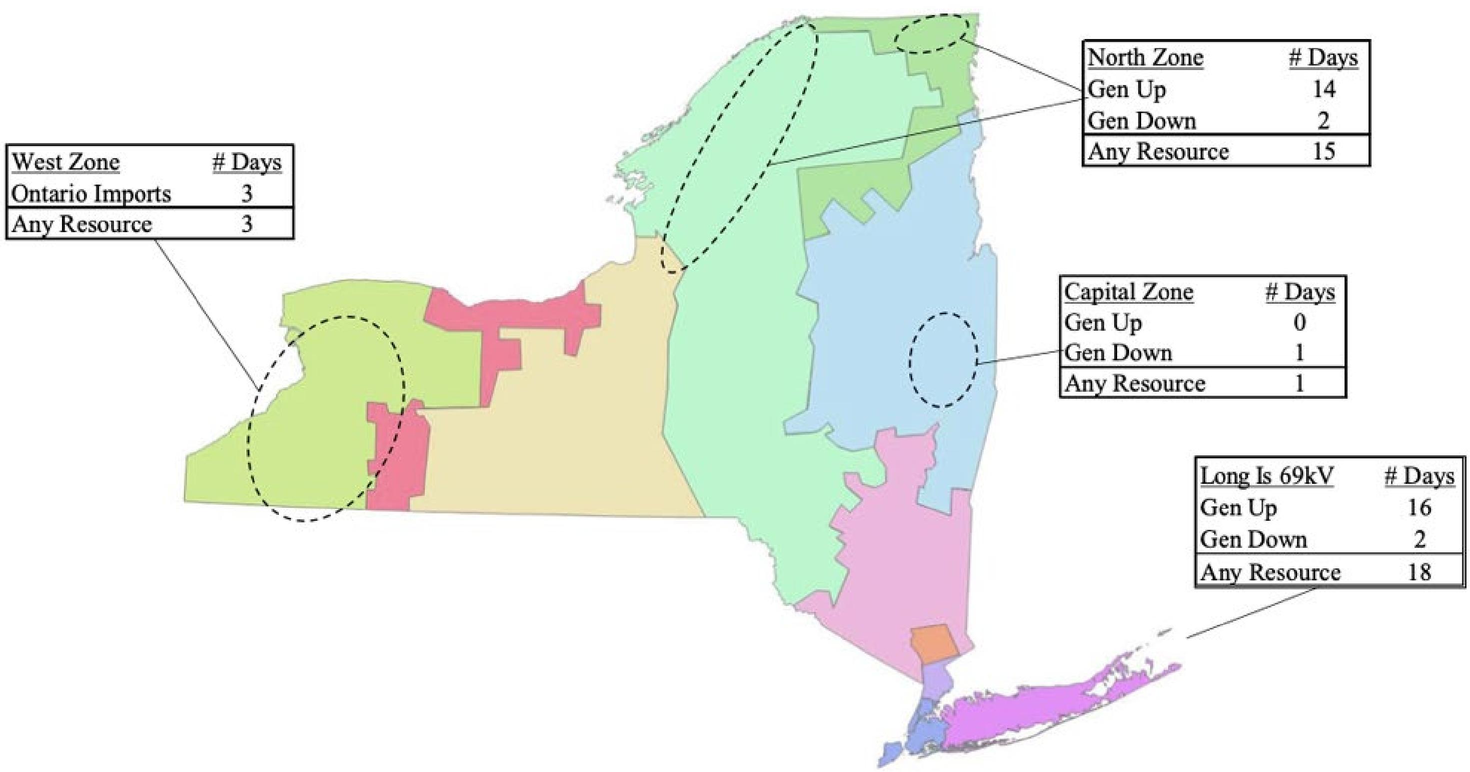
Day-ahead congestion revenues totaled $56 million, down 49% from the first quarter of 2019, primarily because of lower gas prices and load.

"We also saw New York City [Zone J] constraints account for the second largest share of congestion in the first quarter of 2020, but it was mainly localized to the Greenwood load pocket, because a 138-kV Gowanus-Greenwood line was out of service for a lot of January and February, which reduced transfer capability into the Greenwood load pocket," LeeVanSchaick said.

While congestion fell by more than 40% in other regions, congestion in Zone J fell just 16% in the day-ahead market and rose 135% in real time. "So that pocket accounted for most of the New York City congestion, which otherwise would have been relatively small," he said.

### Out-of-market Actions

"In this quarter, we saw a significant reduction in the amount of out-of-market actions to manage low-voltage constraints in New York. Not so much a reduction quarter over quarter, but over the last two years we've seen big reductions," LeeVanSchaick said.




Map shows the number of days in the quarter when various resources were used to manage constraints | *Potomac Economics*

# NYISO News

The ISO achieved the reductions by modeling most 115-kV constraints in the day-ahead and real-time market models, the report said.

"In the West Zone, there were just three days of out-of-market actions where Ontario imports were curtailed to manage Gardenville-to-Dunkirk constraints," LeeVanSchaick said.

Fifteen days of out-of-market actions in the North Zone were predominantly times when the Saranac unit was subject to a supplemental resource evaluation to provide congestion relief as well as operating reserves, while big reductions in the Capital Zone were driven by transmission upgrades, he said. Long Island had 18 days of out-of-market actions, the frequency of which was reduced by low load levels.

"We did see big reductions in the amount of supplemental commitment for reliability ... which was obviously way down both in terms of local reliability rule [LRR] commitments and day-ahead reliability unit commitments," LeeVanSchaick said.

On LRR commitments in New York City, where the ISO is modeling specific load pockets, he showed how the hourly requirement often came in below the static daily requirement, usually because of thermal and voltage constraints that required certain amounts of resources to be committed in certain areas, as the LRR path determines the quantity of resources that are needed on a given day.

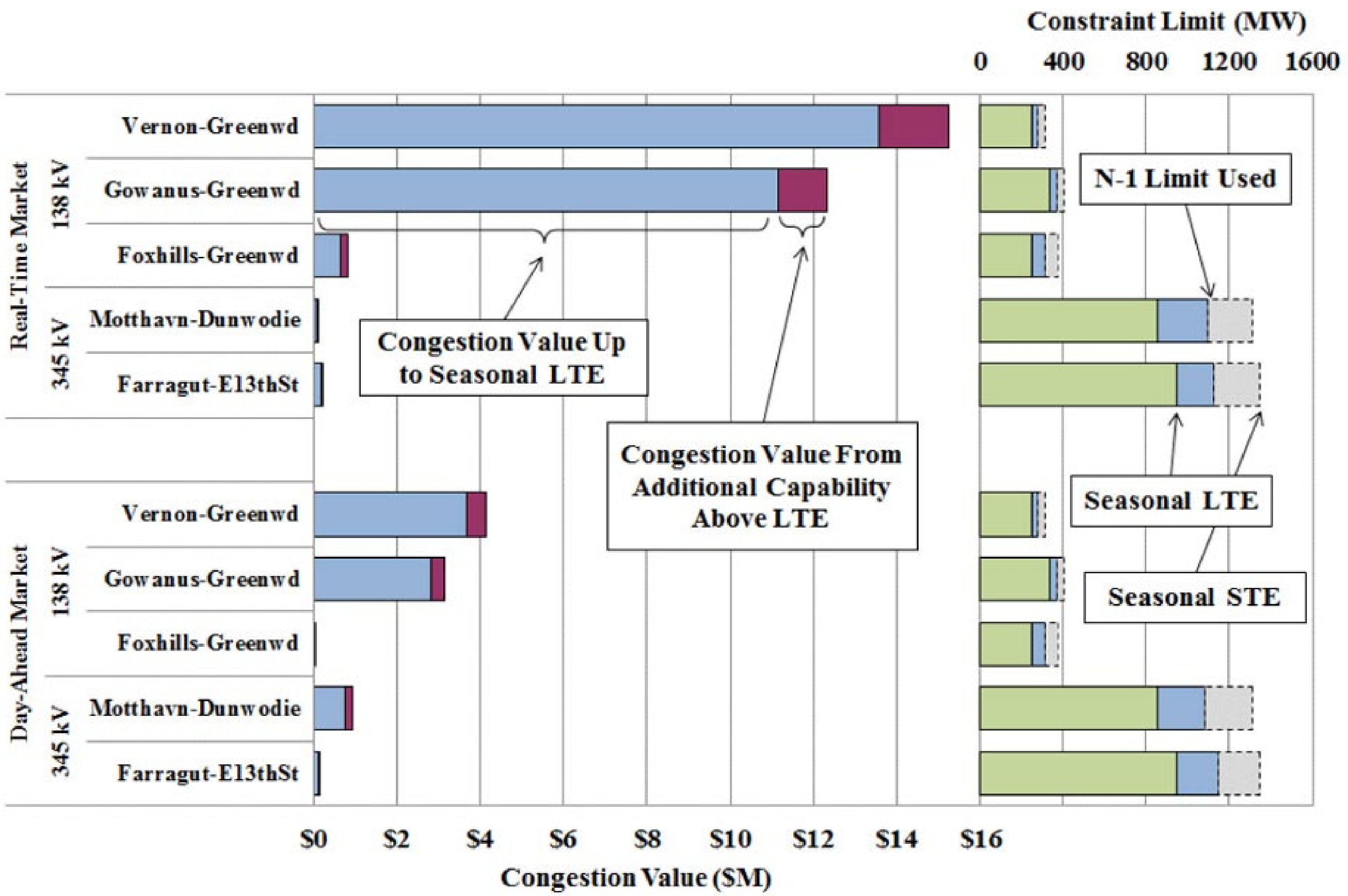
"If we look in the places where commitments occurred ... in terms of the hourly requirement for resources, in [these pockets] you probably need a little over 100 MW in the overnight, but over the peak you need something that averages more like 280 MW," LeeVanSchaick said.

"One thing to note is the actual requirement that's used in the day-ahead software is a static, 24-hour requirement, so if at the peak, 280 MW is needed, even though that's a subset of the hours, the static requirement is essentially imposing that in all 24 hours. So in this quarter, we did see that that led to additional hours of commitment," he said.

The MMU did recommend the ISO examine whether it's possible to represent the requirement only in the hours where the resource is needed in order to avoid excess commitment of generation.

One stakeholder asked whether different resources would be selected if NYISO could better tailor the hourly requirements.

"In principle that could definitely happen," LeeVanSchaick said. "I don't recall that being something we observed in this quarter, but of course it would vary over time and under some conditions that could change the selection." ■




Select N-1 constraints in New York City. The left panel summarizes their day-ahead and real-time congestion values in the quarter, while the right panel shows the seasonal long- and short-term emergency ratings (LTE, STE) for these facilities, compared to the average N-1 constraint limits used in the market software. | *Potomac Economics*

PJM News

# PJM Files EOL Proposal over TO Protest

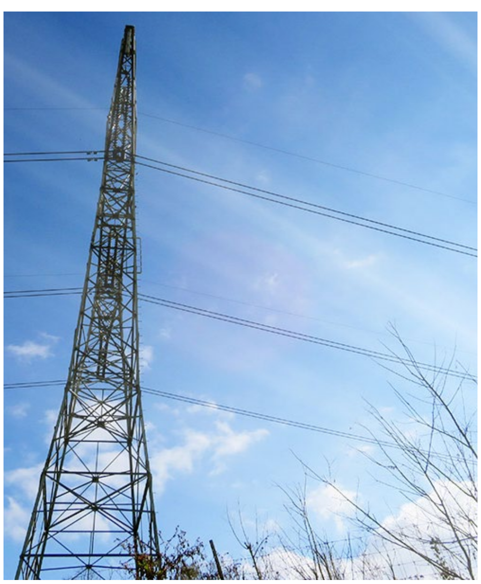
By Rich Heidorn Jr.

PJM filed the joint stakeholders' end-of-life (EOL) proposal with FERC on Thursday, turning aside the protests of most of its transmission owners, who claim moving EOL projects under the RTO's planning authority violates their rights.

The 279-page filing notes that the Operating Agreement amendments, initiated by American Municipal Power (AMP) and Old Dominion Electric Cooperative (ODEC), were approved by 69% of the Members Committee on June 18 despite the RTO's opposition (*ER20-2308*). (See *PJM Stakeholders Endorse End-of-Life Proposal*.)

"While PJM did not support these amendments in the stakeholder process, PJM submits them as the party assigned responsibility under the Operating Agreement to 'administer and implement' the Operating Agreement and to file changes to the Operating Agreement under [Federal Power Act] Section 205."

The filing leaves FERC to decide between the stakeholders' proposal and PJM's plan, which was endorsed by the Transmission Owners Agreement-Administrative Committee (TOA-AC) in a June 12 filing proposing amendments to Tariff Attachment M-3 (*ER20-2046*). It would require TOs to have a formal program for EOL determinations and to identify potential EOL projects five years in advance. Projects that "overlap" with Regional Transmission Expansion Plan (RTEP) violations would be included in a competitive window seeking regional solutions. The RTO's proposal failed to win consensus, with a sector-weighted vote of 36% at the May 28 Markets and Reliability Committee meeting.



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ODEC and AMP have filed a motion to have the TOs' filing dismissed on procedural grounds.

In filing the joint stakeholders' proposal, PJM rebuffed the TOs, who argued in a June 26 *letter* that the proposal violates their rights under the Consolidated Transmission Owners Agreement. (See *TOs Demand PJM Reject EOL Proposal*.)

However, the RTO also filed comments detailing its objections to the joint stakeholders' proposal.

The TOs and PJM contend the stakeholders' proposal also violates FERC precedents and Order 890's rules regarding transmission asset management. PJM has said decisions on when a facility is at the end of its useful life or otherwise needs to be replaced "are the sole responsibility of the transmission owner."

PJM asked FERC to act within 61 days and proposed Jan. 1, 2021, as the effective date for the OA changes, if it accepts them. The RTO said the date would coincide with the beginning of the next cycle of the RTEP.

The joint stakeholders say their proposal complies with commission precedent by continuing to give TOs exclusive authority to determine whether a transmission asset has reached its EOL while making the replacement of such assets PJM's responsibility through the RTEP.

The proposal would:

- modify OA Schedule 6 to create a process for evaluating and replacing EOL assets under the RTEP, removing the planning from Attachment M-3 of the Tariff;
- require TOs to develop an EOL program, including criteria, for facilities approaching their EOL and submit a binding notification to PJM of facilities that will reach their EOL within six years;
- require TOs to provide PJM a 10-year, forward-looking list of facilities' EOL conditions;
- exclude the planning of EOL facilities from the RTEP reliability exemption for transmission facilities under 200 kV; and
- amend the OA definitions and Schedule 6 to remove EOL assets from evaluation as supplemental projects under Attachment M-3 and evaluate all EOL facilities as a separate category under Schedule 6.

PJM told FERC the changes "should be implemented prospectively … as there are no transition provisions in the joint stakeholder proposal for current EOL determinations less than six years out."

### PJM Comments

In separate *comments* filed later Thursday afternoon, PJM said the joint stakeholders' proposal violates its governing documents and commission precedent on the RTO's and the TOs' roles in the planning of supplemental projects, including EOL facilities, and the planning of asset-management projects.

It noted that the stakeholder process "was markedly dominated by legal debates, including debates as to the meaning of certain governing documents and the scope of authority ascribed to PJM and the PJM transmission owners under those documents."

"These legal issues, as well as related policy issues, are not ones that necessarily lend themselves well to final resolution in a stakeholder process," PJM continued. "It is for this reason that PJM is filing these comments and urges the commission to provide clear resolution on the legal and policy issues raised by the joint stakeholder proposal."

The RTO said the proposal that the EOL notifications be binding on the TOs "unreasonably restrict transmission owners' flexibility regarding their end-of-life decisions over their transmission assets. More specifically, this lack of flexibility potentially impedes a transmission owner's ability to modify its end-of-life decisions due to changes to system conditions or unforeseen circumstances that can impact an asset's life. Instead, the proposal assigns the responsibility to PJM to determine whether to escalate or delay replacement of the transmission owner's asset."

It said although the proposal says that "'determination of EOL is still a TO determination,' the proposed revisions specific to EOL conditions seem to effectively assign that responsibility to PJM."

PJM also cited an apparent inconsistency between exempting from the competitive window process EOL notifications on substation equipment while exempting facilities below 200 kV. ■

## PJM News

# PJM Responds to IMM Market Report

By Michael Yoder

PJM has responded to the Independent Market Monitor's annual State of the Market Report, highlighting five different areas of focus out of hundreds of recommendations.

In its response released June 29, PJM said it met with representatives from Monitoring Analytics, the RTO's Monitor, on several occasions in the leadup to the March release of the report to discuss areas of prioritization for 2020. Discussions led to prioritizing five different issues out of 213 recommendations contained in the report, including:

- a holistic review of the auction revenue rights (ARRs) and financial transmission rights markets design;
- five-minute pricing and dispatch;
- a capacity market default market seller offer cap;
- the future of up-to-congestion transactions; and
- energy market power mitigation.

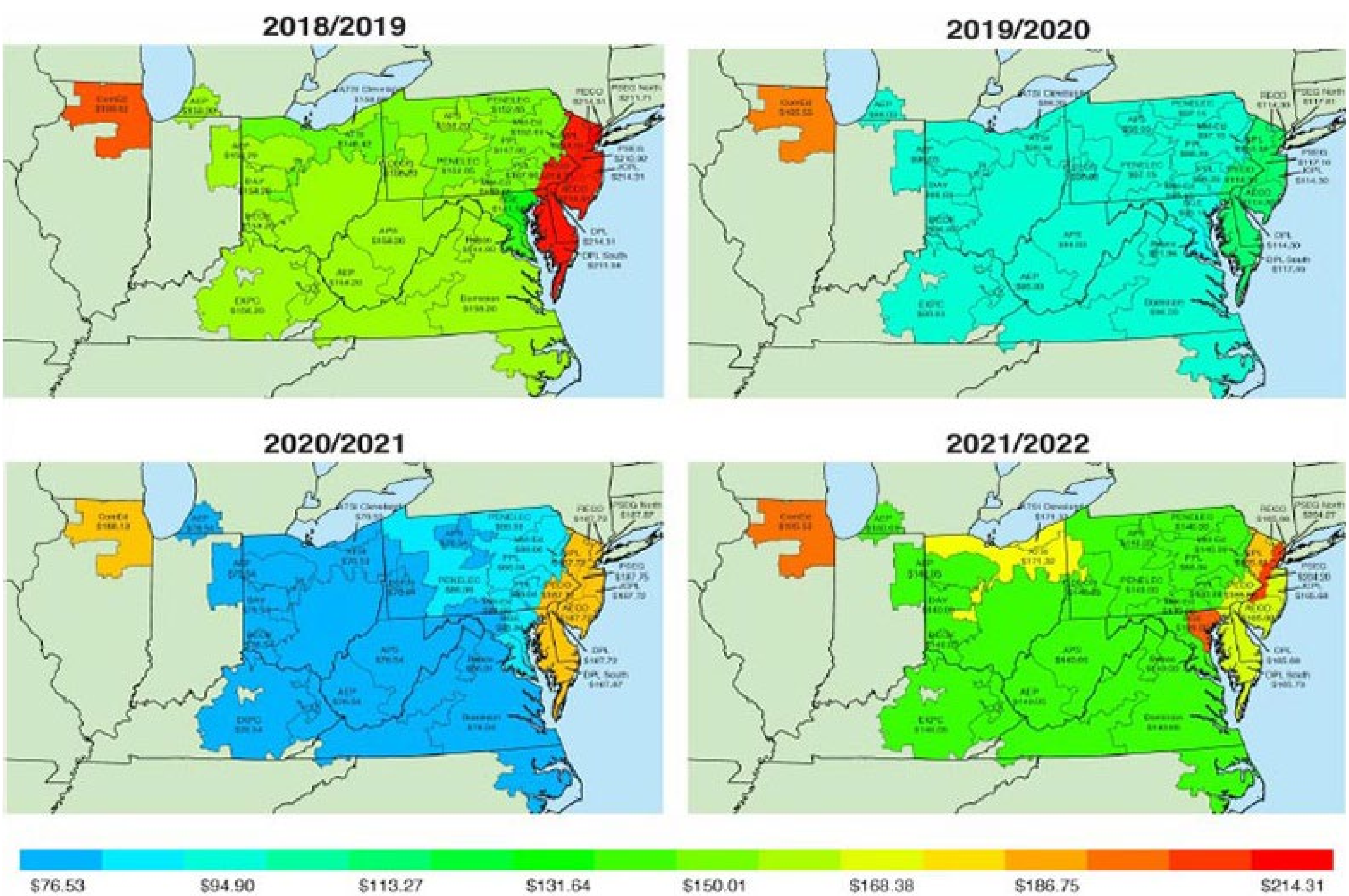
"Some of the recommendations in these areas propose solutions that may require additional analysis by PJM and Monitoring Analytics; stakeholder discussion and vetting; or are recommendations on which PJM and MA have not yet agreed," PJM said in its response.

### ARR/FTR Market Design

The ARR/FTR products have been a major area of focus for PJM, the Monitor and stakeholders in recent years, the RTO said, going back to 2017 when PJM filed changes to comply with a FERC order removing the use of historic source points in the ARR allocation process and shifting the allocation of balancing congestion from FTR owners to load. (See *FERC Accepts PJM's FTR Plan, Rejects Rehearing Requests*.)

The issue took on greater importance after the 2018 GreenHat Energy credit default, PJM said, calling into question the credit requirements for FTRs and the value of the long-term FTR auction. Subsequent discussions at the ARR/FTR Market Task Force have resulted in movements to alter the auction structure.

As a recommendation contained in the independent consultant report on the GreenHat default released last year, PJM is conducting a "holistic review" of the ARR/FTR products and procedures and is in the process of hiring a consultant to conduct a review. PJM reviewed the final scope for the holistic review to be done by the consultant at the June 26 task force meeting. (See *PJM Revises Consultant Scope for ARR/FTR Review*.)




Capacity prices | *Monitoring Analytics*

# PJM News

"PJM is engaging in this holistic review with an open mind and looks forward to working with Monitoring Analytics and stakeholders on the consultant's final report," PJM wrote in its response. "The current structure that is implemented in PJM has been in place for over 20 years. That length of time, in addition to questions raised by stakeholders on the effectiveness of the current structure, necessitates such a review."

## 5-Minute Dispatch and Pricing

In May 2019, the Monitor presented a *problem statement and issue charge* to the Market Implementation Committee addressing transparency and process improvements for real-time energy price formation.

Since then, stakeholders have discussed market rule changes and areas to increase transparency in the governing documents. Several key changes remain under discussion, including: the alignment of energy and reserve prices with the target time of the dispatch instructions; the configuration and periodicity of the dispatch algorithm; the formulation of the real-time dispatch and pricing; and the transparency of the LMP verification process performed by PJM.

Members gave a nearly unanimous endorsement of PJM's short-term *proposal* to resolve issues in *five-minute dispatch and pricing* at the June 3 MIC meeting, while urging the RTO to continue seeking intermediate and long-term solutions. (See *PJM 5-Minute Dispatch Proposal Endorsed*.)

PJM said changes in the alignment of prices and dispatch instructions and frequency and configuration of the dispatch algorithm are "beneficial" and will increase incentives to follow dispatch. The RTO said it cannot currently support proposed changes to the formulation of the real-time dispatch because no analysis is available determining the benefits, costs or operational impacts related to the proposal.

PJM said it appreciates the Monitor raising issues regarding transparency and process improvements around real-time energy price formation.

"The real-time dispatch and pricing of the PJM system is complex," it said. "Taking time to identify where those processes may be improved and where more transparency would be beneficial is important to PJM."

## Default Market Seller Offer Cap

Stakeholders discussed changes to the capacity market's default market seller offer cap (MSOC) at the MIC in 2017 and 2018, advancing a proposal by PJM before it ultimately failed to pass at the October 2018 Members Committee meeting. (See "Market Seller Offer Cap Balancing Ratio," *PJM MRC/MC Briefs: Oct. 25, 2018*.)

The default MSOC is defined as the net cost of new entry multiplied by the average balancing ratio for all performance assessment intervals in the prior three years. The *proposal* would have calculated the balancing ratio used in the default MSOC and nonperformance charge rate formulas by averaging the balancing ratios from the three delivery years that immediately preceded the capacity auction.

Despite lengthy discussions on the issue, consensus was not reached on changes. In February 2019, the Monitor filed a complaint with FERC explaining the problems it believes exist with the current default MSOC (*EL19-47*). (See *Monitor Asks FERC to Cut PJM Capacity Offer Cap*.)

The complaint has yet to be resolved at FERC. PJM said it understands the IMM's justification for the complaint and recognizes that it has resulted in uncertainty in capacity market rules but would have preferred to address the issues outside of FERC rather than waiting for an answer.

| Section | Actionable | Assessment | Archived | Section Percentage |
|---|---|---|---|---|
| Ancillary Services | 11 | 11 | 6 | 13% |
| Capacity Market | 1 | 3 | 25 | 14% |
| Demand Response | 0 | 1 | 26 | 13% |
| Energy Market | 4 | 4 | 36 | 21% |
| Energy Uplift | 1 | 5 | 18 | 11% |
| Environmental | 0 | 1 | 5 | 3% |
| FTRs & ARRs | 2 | 11 | 6 | 9% |
| Interchange Transactions | 3 | 1 | 8 | 6% |
| Net Revenue | 0 | 0 | 1 | 0% |
| Planning | 0 | 3 | 20 | 11% |
| **Total Recommendations** | **22** | **40** | **151** | **213** |
| **Status Percentage** | **10%** | **19%** | **71%** | |

PJM categorization of recommendations from the 2019 State of the Market Report | *PJM*

## UTC Transactions

As a result of changes in market behavior and stakeholder questions on the value of up-to-congestion (UTC) transactions, PJM wrote a *paper* in 2015 providing background and education on their value and highlighted concerns with their use. Recommendations included altering the biddable locations for UTCs to generation buses as source only, trading hubs, load zones and interfaces and allocating uplift to UTCs consistent with increment offers (INCs) and decrement bids (DECs).

The recommendations were discussed at the *Energy Market Uplift Senior Task Force* and culminated in two separate FERC filings, the first of which was accepted in February 2018 and decreased the bidding nodes for virtual transactions in PJM. (See *FERC OKs Slash in Virtual Bidding Nodes for PJM*.)

The second filing, which was rejected by FERC in January 2018, proposed to allocate a portion of the uplift in PJM to UTCs as if they were an INC at the injection point and a DEC at the withdrawal point. PJM and stakeholders chose not to propose an alternative in response to FERC's invitation to do so in its order. (See *FERC Queries PJM on Virtual Transaction Rules*.)

PJM said it believes inconsistencies in the allocation of uplift costs existing between UTCs and other virtual transactions is "inequitable" and should be addressed. The RTO is currently working with the Monitor on UTC analysis.

## Energy Market Power Mitigation

PJM said its energy market power mitigation rules have been the frequent focus of stakeholder discussions and "have presented challenges," including debate over the fuel-cost policy (FCP) process, the lost opportunity cost calculator and parameter-limited scheduling.

In September 2018, stakeholders approved a *problem statement and issue charge* focused on enhancing the FCP process and to explore potential alternatives to PJM's cost-based offer rules. Discussions on the topic are currently taking place within the stakeholder process, as members approved rule changes at the March MC meeting. (See *Revised Fuel-cost Policy Approved by PJM MC*.)

PJM said it supports working with stakeholders and the Monitor to investigate ways to "simplify and streamline the current rules without weakening them" but wants to consider several different components of energy market power mitigation rules to make sure they work together.

"PJM firmly believes that strong market power mitigation mechanisms are critical to maintain an efficient, competitive market," the RTO said. "To ensure those rules remain strong and that they all function cohesively, PJM believes that substantive changes to the calculation of cost-based or mitigated offers should not be considered in isolation." ■

## PJM News

# Hearing Ordered on $154M ATSI Rate Bid

### *Seeks Recovery of MISO 'Legacy' Costs*

*By Rich Heidorn Jr.*

American Transmission Systems Inc. is a unit of FirstEnergy. | *FirstEnergy*

FERC last week ordered hearing and settlement judge procedures on American Transmission Systems Inc.'s (ATSI) request to recover deferred and ongoing legacy costs related to the company's move from MISO to PJM in 2011 (*ER20-1740*).

ATSI's proposed revisions to its transmission formula rate, filed by PJM in May, sought $154 million in additional rates, including legacy MISO Transmission Expansion Plan costs, costs of ATSI's integration into PJM and deferred vegetation management costs.

In 2011, the commission rejected ATSI's first request for recovery of PJM integration costs and MISO exit fees, saying the company had failed to "provide sufficient information or support that would enable the commission to find that it is just and reasonable for ATSI's transmission customers to bear the costs arising from the decision to switch RTOs."

FERC upheld the denial on rehearing in 2016. It said its ruling was without prejudice, allowing ATSI to file a new request that included a detailed cost-benefit analysis showing that the benefits to wholesale transmission customers exceed the costs of the switch to PJM. (See *FERC Rejects ATSI Bid for Cost Recovery on Switch from MISO to PJM*.)

In justifying its new rate request, ATSI, a unit of FirstEnergy, said its move to PJM has generated about $4 billion in benefits, dwarfing the $154 million it seeks to recover.

But American Municipal Power (AMP), Buckeye Power, Industrial Energy Users of Ohio (IEU) and the federal energy advocate for the Public Utilities Commission of Ohio protested the request.

AMP and Buckeye said the request should be rejected because of the four-year delay in refiling for the RTO transition costs since the commission's 2016 rehearing order. AMP said utilities should not have unlimited discretion on how long it will carry deferred costs on its books. AMP, Buckeye and IEU also contended that ATSI's cost-benefit analysis did not accurately calculate the impact on Ohio retail customers.

IEU and AMP also challenged ATSI's request for $18.7 million in deferred vegetation management costs incurred from 2013 to 2016, saying the company failed to demonstrate that they were "enhanced" or prudently incurred.

Citing the disputes, the commission's order accepted ATSI's proposed Tariff revisions and suspended them for five months to become effective Dec. 1, subject to refund. ■

## PJM News

# PJM to Work with States on Policy Goals in New Group

*By Michael Yoder*

Asim Haque, PJM | © *RTO Insider*

PJM has created a new group to work with states to advance energy initiatives like offshore wind and grid security.

The State Policy Solutions group will combine PJM's knowledge of planning, markets and operations with its interpretation of state laws and regulations to help government bodies implement energy policies.

PJM officials said the new group will lend the RTO's "subject matter expertise" to help states reach energy goals and to help facilitate discussions among states or regional groups if efficiencies in policies make sense across multiple government bodies.

"Our states are key stakeholders, and we're committed to partnering with them whenever possible as they contemplate and execute their policy goals," CEO Manu Asthana said in a statement.

The State Policy Solutions group is initially focusing on five areas at its launch, PJM said, including offshore wind, resource adequacy, grid modernization, clean energy targets and grid security. The RTO said the areas were chosen because of their overlap with its main functions.

Tim Burdis, PJM's lead strategist for state government policy, will manage the group, reporting to Asim Haque, the RTO's vice president of state policy and member services.

Haque, who served as chairman of the Public Utilities Commission of Ohio before coming to PJM in 2019, said the group is a response to evolving state energy policies.

PJM CEO Manu Asthana | © *RTO Insider*

Although the RTO has given technical assistance to states in the past, Haque said the new group will provide a more "holistic, end-to-end approach" through the RTO's understanding of state laws, regulations, related cases and FERC orders.

"PJM will always champion its primary duties of keeping the lights on and running efficient markets," Haque said. "At the same time, PJM can utilize its expertise in carrying out those functions to assist our states as they advance their policy objectives. This is an opportunity for us to innovate and partner together in an evolved RTO/multistate dynamic."

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said what the group will be tasked with doing is not totally clear to him or his organization, but he said the group "seems very promising" and that states' access to PJM's expertise will be helpful in decision-making on complicated issues.

"Over the past few years, there have been complaints that PJM has not been responsive to the concerns of the states," Poulos said. "I'm hoping this ushers in a period where PJM works to repair and develop those important relationships."

State regulators and other stakeholders were dismayed when PJM announced last year that Denise Foster had unexpectedly resigned as head of the RTO's State and Member Services Division and that her unit would be realigned. (See *Stakeholders, States in Dark over PJM Personnel Moves*.)

PJM has frequently found itself in the middle of state-federal jurisdictional disputes over energy policy. Illinois and New Jersey officials are considering pulling their utilities from the RTO's capacity market because of FERC's 2019 order expanding the minimum offer price rule.

The RTO is currently considering how it could incorporate carbon pricing for only some of its 14 member states (including D.C.). (See related story, *PJM Carbon Pricing Group Talks RPS, ZECs, RGGI*.) ■

Greg Poulos, CAPS | © *RTO Insider*

PJM News

# Energy Harbor Settles with Solar Co. for $66M

*By Rich Heidorn Jr.*

Energy Harbor will pay almost $66 million to cancel a solar power purchase agreement signed by its predecessor, FirstEnergy Solutions (FES), clearing away another legal battle as it continues to emerge from bankruptcy.

On Saturday, Judge Alan M. Koschik, of the Bankruptcy Court for the Northern District of Ohio, *approved* a stipulation outlining the settlement between Energy Harbor and Maryland Solar Holdings.

The judge's order came three days after FERC granted Energy Harbor's request to hold in abeyance for 90 days a docket the commission had opened to consider whether FES could abrogate its contracts with Maryland Solar and the Ohio Valley Electric Corp. (OVEC) (*EL20-35*).

The commission said it agreed with Energy Harbor that the proceeding would be moot if the bankruptcy court accepted its settlements with Maryland Solar and one announced in May with OVEC.

Energy Harbor agreed to pay Maryland Solar $65.9 million less $1 million in cash collateral held by the solar company for the PPA signed by FES in 2011 for the purchase of renewable energy and related credits. Maryland Solar, which owns a 20-MW solar farm in Washington County, Md., had sought $79.8 million in the dispute.

FES changed its name to Energy Harbor upon emerging from bankruptcy in February, with former bondholders owning 50% of the equity.

Energy Harbor also assumed FES' obligations with OVEC and agreed to pay the company $32.5 million in a settlement approved by the bankruptcy court on June 15. (See *Energy Harbor to Pay OVEC $32.5M in Settlement*.)

In March, FERC ordered a paper hearing to consider FES' attempt to void the OVEC contract and PPA with Maryland Solar as part of its bankruptcy proceeding. The commission acted after the 6th U.S. Circuit Court of Appeals issued a mandate overruling the bankruptcy court's May 2018 injunction preventing FERC from issuing any order requiring FES to continue complying with the contracts. The appellate court also reversed the bankruptcy court's ruling allowing FES to reject the contracts.

In holding the proceeding in abeyance, FERC ordered Energy Harbor to file a report by Sept. 29 updating the commission on the status of the court proceedings.

FERC's order opening the docket said the "jurisdictional contracts" included several wind PPAs signed by FES in addition to the OVEC and Maryland Solar contracts. But Energy Harbor's June 15 motion to hold the FERC docket in abeyance said Maryland Solar and OVEC were "the sole counterparties to the jurisdictional contracts at issue in this proceeding."

A company spokesman clarified that FES had entered into stipulations with all of the other counterparties during the Chapter 11 restructuring proceedings. ■

# PJM Carbon Pricing Group Talks RPS, ZECs, RGGI

*By Michael Yoder*

PJM stakeholders continued their talks last week over integrating carbon pricing while focusing on the impacts of states looking to join regional environmental collectives like the Regional Greenhouse Gas Initiative.

Jen Tribulski of PJM led a discussion of stakeholders' interests during the June 30 *Carbon Pricing Senior Task Force* meeting.

Neal Fitch of NRG Energy gave a *presentation* noting that carbon pricing is being expressed in direct programs through states that have already joined RGGI and also indirectly through renewable portfolio standards and zero-emission credits (ZECs). Fitch said the indirect carbon pricing programs involve a "fairly significant amount of money" that needs to be addressed, including $4.4 billion in total RPS costs from 2014 to 2018 compared to $1.4 billion raised in RGGI auctions over the same time period.

Fitch said PJM must ensure it considers all programs at the state level that are driving carbon costs while addressing the possibility of direct carbon pricing in the RTO. He said NRG would like to see debates on ways PJM could utilize existing state programs to transform them into a vehicle to achieve carbon-reduction goals at a lower cost through greater efficiency.

"We don't want to lose sight that there are a lot of levers already in play regarding carbon pricing," Fitch said.

Border adjustments and leakage have been some of the most hotly debated issues regarding carbon pricing. (See *PJM Panel Weighs Impact of Pa., Va. Joining RGGI*.) But Fitch said as more states decide to adopt carbon pricing, border adjustments become less of an issue because they are "remedied as states migrate toward a consensus position on carbon regulation."

"As the progress and expansion of carbon regulation goes beyond one or two states, the need to address leakage and border adjustments remedies itself," Fitch said.

Jason Barker of Exelon asked Fitch if NRG is asking that the task force not address border adjustments or leakage in future discussions.

Fitch said border adjustments and leakage remain "something to contemplate" and that he would want them fully addressed and vetted before moving too far ahead. He said stakeholders who find border adjustments to be a "constraint" when discussing carbon pricing may be more comfortable with carbon pricing as the borders go away with more states adopting environmental standards.

Barker said one of the interests Exelon has for the task force is seeing how stakeholders can both enhance the value of the carbon programs states are undertaking while also recognizing time is an element in the discussions. Barker said Exelon doesn't want to lose sight of what can be accomplished in the short term while pursuing broader solutions over the longer term.

"There have been decades of talk about carbon pricing, and it hasn't happened other than in a state-by-state basis," Barker said.

Michael Borgatti of Gabel Associates spoke on behalf of the American Wind Energy Association, the Solar Energy Industries Association and 27 other organizations who were signatories of a *letter* sent to the PJM Board of Managers on June 26 calling for continued discussions on carbon pricing. ■

# Md. PSC OKs Independence Energy Connection Deal

*By Michael Yoder*

The Maryland Public Service Commission last week approved a settlement allowing Transource Energy to move forward with its controversial Independence Energy Connection (IEC) transmission project.

In its *order* issued June 30, the PSC said Transource can build the 4.5-mile western portion of the 230-kV overhead transmission line from Washington County, Md., to a substation in Franklin County, Pa.

Baltimore Gas and Electric will build the 6.6-mile eastern portion of the project, comprising two segments from substations in Harford County, Md., to a substation across the border in York County, Pa. (Case No. *9471*).

Signing the settlement in addition to Transource were the Maryland Power Plant Research Program, the commission's technical staff, BGE, Harford County and landowner parties, including the group STOP Transource Maryland.

The Harford County segment of the project, which also crosses portions of Baltimore County, was redesigned from the original proposal to avoid greenfield construction through the utilization of BGE's existing utility infrastructure and rights of way. Transource filed the second configuration for the IEC East project with Maryland and Pennsylvania regulators in October after settling with landowners and state officials opposed to the original route of a nearly 16-mile-long new transmission line. (See *Transource Files Reconfigured Tx Project*.)

The PSC directed Transource and BGE to minimize all construction activities and additional construction-related costs until the project wins the approval of the Pennsylvania Public Utility Commission and final approval by PJM. It concluded that portions of the proposed transmission line in Maryland will "address existing and future regional congestion issues," while reducing impacts on the environment, agricultural activities and natural resources.

"The commission finds that this project will provide benefits to Maryland ratepayers, including enhanced reliability of electricity service and greater access to least-cost energy from elsewhere within PJM, while also accommodating future development of renewable technologies such as offshore wind," PSC Chair Jason Stanek said in a statement.

In 2016, PJM identified the IEC project as a solution to relieve congestion on the AP South interface. Transource filed its initial applications with the Maryland and Pennsylvania commissions in 2017.

The Harford County segment of the project, which also crosses portions of Baltimore County, was redesigned from the original proposal to avoid greenfield construction through the utilization of BGE's existing utility infrastructure and rights of way. Transource filed the second configuration for the IEC East project with Maryland and Pennsylvania regulators in October after settling with landowners and state officials opposed to the original route of a nearly 16-mile-long new transmission line. (See *Transource Files Reconfigured Tx Project*.)

PJM's analysis of the new IEC East configuration determined it will cost $496.2 million and realize $844.8 million in congestion benefits. The analysis ran into protests by PJM stakeholders last year, who said the project did not meet the RTO's cost-benefit test. (See *PJM Analysis of Transource Alternative Challenged*.)

Nils Hagen-Frederiksen, press secretary for the Pennsylvania PUC, said the proposed settlement regarding the Pennsylvania portions of the IEC project is pending *regulatory approval* before the commission. Hagen-Frederiksen said additional evidentiary hearings are scheduled for July 9 and 10 before the PUC administrative law judges, with briefs from all parties due in mid-August and reply briefs due for a yet-to-be determined date.

"At some point, after all the briefs have been filed and the record has been closed, the administrative law judges will review all of the case materials and issue a recommendation for the full commission to consider as part of their final decision, but there is no specific schedule for that," Hagen-Frederiksen said. ■


Transource's proposed alternative plan for the eastern segment of its Independence Energy Connection project | *Transource Energy*

## SPP News

# Regulatory Setback Doesn't Stop AEP Wind Project

## *Texas PUC Again Rejects SWEPCO Bid for Rate Recovery*

*By Tom Kleckner*

Texas regulators Thursday rejected their ratepayers' participation in an American Electric Power wind project for the second time in three years, denying a plan by subsidiary Southwestern Electric Power Co. (SWEPCO) to add 810 MW of wind energy (*49737*).

The Public Utility Commission's denial will not affect AEP's $2 billion North Central Wind Project, comprising three wind farms in Oklahoma that will provide 1,485 MW of capacity. Arkansas, Louisiana and Oklahoma regulators have already approved the project, as has FERC. The Arkansas and Louisiana approvals included "flex up" provisions that increase capacity allocations in case of a state's rejection. (See *AEP a Go with $2B North Central Wind Project*.)

An estimated 464 MW of capacity will now be allocated to SWEPCO's Louisiana customers and 268 MW to Arkansas customers. SWEPCO sister company Public Service Company of Oklahoma's (PSO) share will remain at 675 MW. SWEPCO wholesale customers will receive an additional 78 MW.

SWEPCO President Malcolm Smoak reiterated that the PUC's order does not affect North Central's "full viability."

Invenergy is building the three North Central wind farms. | *Invenergy*

"It is disappointing that our customers in East Texas and the Panhandle will not have access to this major wind project, missing the opportunity for long-term cost savings and making it more difficult for businesses, residents and communities to meet their renewable energy goals," he said in a *statement*.

AEP says the North Central wind facilities will save its SWEPCO and PSO customers $3 billion over the next 30 years.


AEP's North Central Wind Project will involve three wind farms in Oklahoma. | *AEP*

The Texas commission rejected that argument in approving administrative law judges' *proposed decision*. The ALJs said the North Central wind facilities "will significantly increase SWEPCO's rate base, with some of the financial risk placed on the customers rather than the shareholders."

SWEPCO's request was opposed by most intervening Texas consumer groups. They pointed out that the wind generation is not needed for SWEPCO's capacity needs. PUC Chair DeAnn Walker agreed, noting the utility is projected to have excess capacity until 2026.

"How this has been laid out is not something that I can go with," she said.

"There are features of the project that I really like, but if you bring us a project [that benefits consumers], yet all consumer groups are opposed," Commissioner Arthur D'Andrea said, "it makes it difficult to grant that."

"It seems like the quantification of benefits … did not become, to me, convincing," added Commissioner Shelly Botkin.

Invenergy is developing the three wind farms. One is expected to be completed this year, the other two by the end of 2021. SWEPCO and PSO will acquire the facilities upon their completion.

In 2018, the PUC similarly denied SWEPCO's attempt to acquire a 70% interest in AEP's proposed $4.5 billion Wind Catcher Energy Connection. AEP canceled the project the day after the commission's rejection. (See *AEP Cancels Wind Catcher Following Texas Rejection*.) ■

## SPP News

# Tri-State, Delta Officially Part Ways

## *Cooperatives End 28-Year Power Relationship*

*By Tom Kleckner*

Tri-State Generation and Transmission Association and Delta-Montrose Electric Association (DMEA) officially parted ways last week, wishing each other well after 28 years of partnership.

The two cooperatives in April entered into a membership withdrawal agreement in which DMEA agreed to pay an $88.5 million exit fee in accordance with a July 2019 settlement agreement. (See *Tri-State G&T, Delta-Montrose Reach Withdrawal Deal*.)

FERC approved the breakup last month (*ER20-1541, et al.*). The Colorado Public Utilities Commission accepted the settlement agreement last year.

In a *joint press release* June 30, each of the cooperatives' CEOs extended best wishes to the other organization and its members. It was a friendly ending to a relationship that had turned acrimonious over the last 15 years. DMEA refused Tri-State's 2005 request of its members to extend their contract from 2040 to 2050 to help pay for a coal-fired plant in western Kansas. Tri-State eventually pulled out of the Holcomb project and has begun a shift to renewable power as part of its *Responsible Energy Plan*. (See *Tri-State to Retire 2 Coal Plants, Mine*.)

In 2016, DMEA served notice to Tri-State that it planned to leave the partnership, saying it wanted to pursue cheaper renewable power and escape rates that had risen 56% since 2005. Tri-State initially asked for a reported $322 exit fee but settled with DMEA on the final amount.


DMEA's headquarters in Montrose, Colo. | *Delta-Montrose Electric Association*

DMEA CEO Jasen Bronec | *Delta-Montrose*

Wholesale provider Guzman Energy, which has entered into a contract with DMEA, will pay Tri-State $72 million for DMEA's contract while the co-op will pony up $26 million to Tri-State for transmission assets. DMEA also forfeited another $48 million in patronage capital to depart.

Tri-State and DMEA have also entered into new contracts for the continued operation of transmission and telecommunications systems.

"This separation marks a new chapter for both DMEA and for Tri-State, and as cooperatives, we both know it's important to look forward for the benefit of our members," DMEA CEO Jasen Bronec said. "We recognize our ongoing partnership with Tri-State in various areas, such as transmission, and appreciate the importance of our continued cooperation."

DMEA, a rural distribution cooperative that serves about 28,000 member-owners in western Colorado, is the second member to leave Tri-State in recent years. Kit Carson Electric Cooperative left in 2016, with Guzman paying its $37 million exit fee.

Westminster, Colo.-based Tri-State is a not-for-profit cooperative with 45 members following DMEA's exit. It has 42 member utility distribution cooperatives and public power districts in four states, with more than a million customers in nearly 200,000 square miles of the West.

Two of Tri-State's three largest remaining cooperatives, United Power and La Plata Electric Association, are seeking their own early exits through proceedings at the Colorado PUC.

FERC last month set hearing and settlement judge procedures on Tri-State's proposal for computing member exit fees (*ER20-1559*). The commission accepted Tri-State's methodology but said it raises issues of material fact that cannot be resolved based on the existing record and has not been shown to be just and reasonable. (See *FERC Sets Tri-State's Exit-fee Rules for Hearing*.) ■

## SPP News

# FERC Approves SPP's 2nd Go at Dropping Z2 Credits

By Tom Kleckner

FERC last week approved SPP's second effort to eliminate revenue credits for sponsored transmission upgrades under Tariff Attachment Z2 and replace them with incremental long-term congestion rights (ILTCRs), effective July 1 (*ER20-1687*).

The commission in January rejected an earlier attempt to eliminate the revenue credits, giving SPP an opportunity to file a revised proposal that "does not impose a cap that limits the term and potential value of ILTCRs." (See *FERC Order Keeps Z2, Aids EDF's Sponsored Project*.)

The RTO responded in April with a filing that proposed to remove the cap on the amount recoverable through the candidate ILTCRs and revert back to current provisions allowing those ILTCRs a term of at least 10 years and up to 20 years.

The June 30 order was a defeat for renewable developers, who contended that SPP's proposal would violate FERC's cost allocation policies because upgrade sponsors — generally wind and solar facilities — would no longer receive direct payments from third parties who benefit from an upgrade. They argued SPP could not remove Z2 credits without trying to replace them with another mechanism "that considers whether others benefit from these directly assigned network upgrades."

The commission disagreed, saying upgrade sponsors receive ILTCRs as a form of compensation for being directly assigned network upgrade costs. Third-party beneficiaries of incremental network upgrades "will continue to indirectly pay for such upgrades through congestion payments," it wrote.

"To the extent that an upgrade is utilized at its full capacity in the day-ahead energy market and thus generates congestion rent … a load-serving entity whose power consumption contributes to congestion on the upgraded facility will fund ILTCRs associated with the upgraded facility through its congestion payments," FERC said.

Under Attachment Z2 of SPP's Tariff, transmission customers that fund network upgrades can be reimbursed through transmission service requests, generator interconnections or upgrades that could not have been honored "but for" the upgrade.

SPP has been trying to replace Z2 credits since 2016, when controversy arose after the grid operator identified eight years of retroactive credits and obligations that had to be resettled after staff failed to apply credits. (See *SPP Invoices Lead to Confusion on Z2 Payments*.)

In a separate proceeding related to the retroactive Z2 payments, FERC in February denied SPP's request for a rehearing of a 2019 order that the RTO provide refunds of credit payment obligations (*ER16-1341*). (See *FERC Denies Rehearing in Z2 Remand Order*.) SPP and Oklahoma Gas & Electric have appealed the decision to the D.C. Circuit Court of Appeals, where the matter is expected to be set through a briefing process, according to the RTO.

### FERC Accepts Generator-replacement Proposal

FERC on June 30 also accepted SPP Tariff revisions that create procedures for expedited replacement of existing generating facilities when the replacement is not a material modification, effective July 1 (*ER20-1536*).

The commission said SPP's procedures will avoid duplicative study costs and operational costs that otherwise would occur when the replacement request must proceed through the interconnection study queue process, delaying the addition of more efficient and cost-effective resources. FERC said the proposal will prevent generator owners from losing their existing interconnection service and potentially incurring "significant costs" to obtain replacement service at the same location.

"We find that SPP's proposal will allow for more efficient use of the transmission system by streamlining the current replacement process," the commission said.

FERC found SPP's proposed process complies with Order 2003, which requires public utilities that own or operate transmission to file generator interconnection procedures for facilities with capacity greater than 20 MW. The order provides for pro forma large generator interconnection procedures (LGIP) but allows for variations consistent with or superior to the standard LGIP.

In its April filing, SPP said its proposal will encourage owners of existing facilities to upgrade to newer, more efficient technology.

### Multiday Minimum Run Time OK'd

FERC's Office of Energy Market Regulation on June 30 issued a letter order accepting SPP's Tariff revisions that allow market-committed resources with a minimum run time extending beyond initial reliability unit commitment or day-ahead commitment periods to be eligible for make-whole payments after their initial commitment period (*ER20-1782*).

Z2 credits for transmission upgrades will soon be a thing of the past for SPP members. | *Apex Clean Energy*

The RTO's stakeholders approved the change in January. It is intended to minimize potential gaming opportunities identified by the Market Monitoring Unit. (See "Members Pass 12 Revision Requests," *SPP MOPC Briefs: Jan. 14-15, 2020*.)

### FERC to Examine Roughrider's Formula Rate

FERC on June 30 also accepted SPP's Tariff revisions that add a formula rate template and implementation protocols allowing Roughrider Electric Cooperative to recover its annual transmission revenue requirement (ATRR) as a transmission-owning member of the RTO, effective July 1 (*ER20-1750*).

However, the commission said its preliminary analysis indicates the proposed revisions may be unjust and set them for hearing and settlement judge procedures. Missouri River Energy Services had protested the filing, arguing that it lacked adequate detail about the source of certain construction costs.

Roughrider, embedded in the Integrated System as a Basin Electric Power Cooperative member, joined SPP on April 30 and has been placed in the RTO's Upper Missouri pricing zone. The North Dakota distribution cooperative serves more than 8,000 members in six counties. It purchases power through Montana's Upper Missouri Generation & Transmission Cooperative and also sources energy from SPP members Basin Electric Power Cooperative and Western Area Power Administration.

FERC did not suspend and subject Roughrider's ATRR to refund obligations because the co-op is not within the commission's jurisdiction under Section 205 of the Federal Power Act. However, it noted that Roughrider voluntary agreed to issue refunds should it change under the hearing and settlement judge process. ■

# Company Briefs

### AEP Signs PPA for 400 MW

AEP Energy announced last week that it has signed a long-term power purchase agreement with an affiliate of Copenhagen Infrastructure Partners for 400 MW of renewable energy from Panther Grove Wind Energy Facility in Illinois.

AEP will use the power to serve customers, such as Google, who want clean energy for their retail supply. Construction is scheduled to begin in early 2021, with commercial operation expected in late 2022.

More: *AEP*

### Berkshire Hathaway to Buy Natural Gas Assets from Dominion

Berkshire Hathaway said last week it is purchasing natural gas transmission and storage assets from Dominion Energy in a deal worth nearly $10 billion. Berkshire will pay $4 billion in cash for the assets in addition to assuming $5.7 billion in Dominion debt.

As part of the deal, Berkshire will acquire full ownership of Dominion Energy Transmission, Questar Pipeline and Carolina Gas Transmission, as well as a 50% operating interest in Iroquois Gas Transmission System and a 25% operating interest in LNG shipping facility Cove Point.

The deal, pending regulatory approval, is expected to close in the fourth quarter of this year.

More: *CNN Business*

### CenterPoint Names New CEO

CenterPoint Energy last week announced it has named the former head of Halliburton, David J. Lesar, as its new president and CEO. Lesar, whose appointment became effective July 1, succeeds John W. Somerhalder II, who stepped in as interim president and CEO in February.

CenterPoint will pay Lesar an annual salary of nearly $1.4 million with an additional $1 million in stock as a signing bonus.

Lesar was chairman and CEO of Halliburton, a top three oil-field service, from 2000 to 2017 before retiring in 2018 after spending a year as executive chairman.

More: *Houston Chronicle*

### CPS Energy Puts Workers Under Quarantine

CPS Energy last week said it has put 246 workers under quarantine after 32 of its employees tested positive for COVID-19. In all, 8% of the company's 3,083 employees are now under quarantine.

Spokeswoman Melissa Sorola said many of the quarantined employees were working from home.

More: *San Antonio Express-News*

### ENGIE, Hannon Armstrong Form Renewables Partnership

The North American arm of European energy giant ENGIE and climate-focused investor Hannon Armstrong announced last week they will partner on a 2.3-GW portfolio of U.S. wind and solar projects slated for completion this year.

The two will split equity ownership of the portfolio, with ENGIE maintaining a 51% majority interest and managing the projects. The portfolio includes wind installations in South Dakota, Kansas, Oklahoma and Texas, as well as solar projects in Texas and Virginia. By the end of 2020, ENGIE hopes to have constructed 2.3 GW of renewables in the U.S.

Hannon CEO Jeff Eckel said the investment will help the company diversify and scale its own investment portfolio, which has recently tilted toward solar. Behind-the-meter projects in energy efficiency, storage and distributed solar currently make up most of its $2.1 billion portfolio.

More: *GreenTech Media*

### SPP Reports Staff's First COVID-19 Case

SPP last week announced its first confirmed case of COVID-19 among employees but said no other employees were exposed. In a *message to stakeholders*, CEO Barbara Sugg said the RTO's contact-tracing protocols determined the employee had not been on its Little Rock, Ark., corporate campus throughout the pandemic.

"SPP's minimal exposure to COVID-19 is a testament to the precautions our organization has taken and the dedication our staff have to each other's safety and health," Sugg said. Arkansas reported a record 878 positive cases on July 2, more than double the cases reported the day before. The state has record 279 deaths.

Most SPP employees have been working from home since March, when the RTO also suspended in-person meetings. Sugg said Sept. 8 remains its target date for a phased return to its corporate campus, but that depends on "measures of community health and safety."

# Federal Briefs

### Dominion, Duke Back out of Atlantic Coast Pipeline

Dominion Energy and Duke Energy, which spent $3.4 billion trying to get the Atlantic Coast Pipeline off the ground, officially abandoned their six-year bid to build it on Sunday, saying it had become too costly and the regulatory environment too uncertain to justify further investment.

Company officials said other recent federal court rulings linked to the Keystone XL pipeline have heightened the litigation risk, extended the project's timeline and further ballooned the cost of the project from an estimated $5 billion in 2014 to $8 billion today. The companies also cited a May 28 ruling by a Montana district judge when a ruling threw into question the Army Corps of Engineers' permitting program (Nationwide 12), which allowed gas and oil pipelines to traverse wetlands and bodies of water.

The 600-mile pipeline would have tunneled under the Appalachian Trail on its way from West Virginia through Virginia and into North Carolina.

More: *The Washington Post*

### EPA to End Suspension of Pollution Monitoring

EPA last week said it will rescind its policy that allowed companies to skip monitoring their pollution by Aug. 31.

The policy, unveiled in a March 26 memo in an effort to help companies reduce regulatory burdens during the COVID-19 pandemic, told companies they would not face penalties for failing to monitor pollution emissions as required under environmental laws. Lawmakers quickly pressured EPA to end the policy, saying the agency had no way of knowing how much pollution might be emitted without sufficient monitoring.

More: *The Hill*

### Federal Judge Orders Dakota Access Pipeline to Close

D.C. District Court Judge **James Boasberg** on Monday ruled that the Dakota Access oil pipeline in North Dakota must be emptied while the Army Corps of Engineers conducts the environmental impact review. Boasberg claims the review should have been completed before it granted an easement that allowed Energy Transfer Partners to build the pipeline in the first place.

The court said the corps violated the National Environmental Policy Act when it granted an easement to the company to construct and operate a segment of the pipeline running beneath Lake Oahe because it failed to produce an adequate environmental impact statement.

The company must close the pipeline within 30 days.

More: *POLITICO*; *Reuters*

### House Sends Infrastructure Bill to Senate

The House last week voted 233-188 to pass a $1.5 billion infrastructure bill that would cover everything from roads to broadband, however it is expected to have little chance of being signed into law as written.

Senate Majority Leader **Mitch McConnell** (R-Ky.) ridiculed the bill, calling it "nonsense," "absurd" and "pure fantasy," saying it will die in the Senate. Furthermore, the White House has indicated it would veto the bill.

Though the bill in its current form is not likely to go anywhere, the core of the bill (transportation-specific functions) are almost guaranteed to survive, though the chambers may not agree on what the final form will be until next year.

More: *POLITICO*

### Senate Nixes Proposal Limiting DOE's NNSA Budget Control

The Senate last week nixed a provision in the National Defense Authorization Act that would have limited the Department of Energy's control over the National Nuclear Security Administration's (NNSA) budget.

The original proposal included a stipulation that would have given the Nuclear Weapons Council, which includes personnel from both the Defense and Energy departments, review power over Energy Secretary Dan Brouillette's proposed budget for the NNSA. However, the chamber unanimously adopted an amendment giving DOE final say.

The NNSA is an agency within the Energy Department that uses nuclear science for military purposes and is charged with maintaining the nuclear weapons stockpile and responding to nuclear emergencies.

More: *The Hill*

### US Solar Plants Expected to Run at Least 30 Years

The assumed useful life of solar projects now averages 32.5 years, up from 21.5 years in 2007, according to a plethora of developers, sponsors, owners and consultants conducted by the Lawrence Berkeley National Laboratory.

At the same time, the industry has slashed operations costs by half, with levelized lifetime expenditures falling from an average of $35/kW-year for projects built in 2007 to $17/kW-year for projects built in 2019. Also, the levelized cost of energy of utility-scale PV projects declined from an average of $305/MWh for projects built in 2007-2009 to $51/MWh for projects built in 2019. The cost reduction was attributed to lower upfront capital expenditures.

More: *GreenTech Media*

# State Briefs

## CALIFORNIA

### Channel Islands' RMR Gets Tentative FERC OK

FERC last week tentatively accepted a reliability-must-run contract between CAISO and Channel Islands Power, a 27.5-MW combined cycle gas-fired plant operated by California State University Channel Islands in Camarillo.

The commission established hearing and settlement judge procedures to further explore issues raised by Southern California Edison, the Public Utilities Commission and six municipal utilities, who each contested various aspects of the cost estimates CSU used to calculate compensation under the agreement. CAISO sought the RMR to help meet a 288-MW local capacity requirement in the Santa Clara subarea. (See *CAISO Board OKs $141.7M Tx Plan, RMR Contracts*.)

The plant previously operated under a resource adequacy agreement with SCE, which expired in March.

More: *ER20-1708*

### San Francisco Advances New Building Gas Ban

San Francisco Board of Supervisors member Rafael Mandelman and the Department of the Environment are moving forward with a new draft ordinance they announced on June 30 that would prohibit the city from issuing construction permits for new buildings that include natural gas hookups. After Jan. 1, 2021, the city would only issue permits for residential and commercial buildings with all-electric heating systems, stoves and appliances.

The draft says San Francisco's geography, topography and population density put the city at increased risk of gas infrastructure fires and explosions caused by earthquakes and landslides.

Since 2019, 30 local governments have

passed restrictions on gas use in new construction.

More: *S&P Global Market Intelligence*

## INDIANA

### IURC Rejects Utilities' Request to Collect Lost Revenue

The Utility Regulatory Commission last week unanimously voted to deny a request from 10 utilities who said they needed to recover millions of dollars in lost revenue as businesses and factories used less electricity the last few months because of the COVID-19 pandemic.

The ruling followed an uproar from ratepayers and elected officials, who called the request "undeserved special treatment" and unfair to businesses who are dealing with lost revenue. The utility consumer office said the utilities did not present evidence they were facing financial emergencies.

In related news, the IURC prohibited utilities from disconnecting any customers, or collecting late fees, convenience fees, deposits and reconnection fees, through Aug. 14.

More: *Indianapolis Business Journal*

## MAINE

### Judge Says Anti-NECEC Question Can Go to Ballot

Superior Court Judge Thomas Warren last week dismissed a challenge to a pending ballot question opposing Central Maine Power's $1 billion New England Clean Energy Connect transmission line, saying any ruling prior to the question being voted on in November would be pre-emptive.

Warren said that while CMP's parent company, Avangrid, raised legitimate questions about whether the citizens' initiative to overturn the Public Utilities Commission's approval of the project would violate the state constitution, such a ruling is not necessary before the issue is put to a vote. He said the question of constitutionality "must be reserved for future litigation if the proposed initiative is enacted."

More: *Bangor Daily News*

### FERC Accepts Emera Maine Settlement

FERC last week accepted a settlement between Emera Maine, the Public Utilities Commission, the Office of Public Advocate and several municipal utilities over Emera's transmission rates in the northern portion of its service territory.

The state agencies and utilities had challenged Emera's annual transmission rate update in 2018 for the Maine Public District, which includes Aroostook County and a small portion of Penobscot County. FERC decided on four of the eight issues the groups raised but ordered hearing and settlement judge procedures on the other four. (See *FERC Orders Settlement on Emera Maine Tx Rate Dispute*.)

As part of the *settlement*, filed in March, the parties agreed to numerous provisions regarding Emera's rates, such as formulas, values, expenses and accumulated deferred income taxes. For example, the parties agreed on how much of the costs of rebuilding Line 6901 that Emera can recoup from ratepayers.

FERC staff *said* in April that the settlement "reflects thoughtful and reasoned negotiations undertaken by all participants in good faith, and resolves all four issues set for hearing and settlement judge procedures by the commission." There were no other comments either for or against the settlement.

More: *ER15-1429-012*

## MICHIGAN

### Enbridge Allowed to Reopen Portion of Damaged Line 5

An Ingham County judge last week overturned a June 25 restraining order that prevented Enbridge from using its Line 5 oil pipeline beneath the Straits of Mackinac, allowing some oil to resume flowing.

The judge's ruling allows flow to resume through the west leg while the company conducts an in-line investigation, which involves sending a device into the pipe to determine if there is evidence of internal damage. Enbridge must provide state attorneys "all obtained data and all conclusions" within seven days after the west leg is reopened.

A restraining order on reopening of the east leg remains in place until the U.S. Pipeline and Hazardous Materials Safety Administration lifts it.

More: *MLive*

## NEBRASKA

### Plum Creek Wind Project Completed on Schedule

Ørsted last week said it has officially completed the 230-MW Plum Creek wind farm in Wayne County.

The facility, which is the company's first in the state, consists of 82 turbines. Ørsted has already entered into agreements with companies to purchase the power, including Vail Resorts, The J.M. Smucker Co. and Avery Dennison Corp.

More: *North American Windpower*

## OHIO

### PUCO Fines Dominion for Pepper Pike Explosion

The Public Utilities Commission last week fined Dominion Energy $1 million for a November gas pipeline explosion in Pepper Pike, saying the cause of the explosion was the "failure of a 30-inch steel distribution main that released natural gas into the atmosphere, which subsequently ignited."

Under an agreement reached with Dominion, the commission can impose an additional $500,000 if it finds that the utility does not fulfill the terms of the settlement or implementation plan. The agreement also requires Dominion to create a plan to improve its gas safety program.

More: *Cleveland.com*

## OREGON

### Portland General Electric Launches Virtual Power Plant Pilot

Portland General Electric last week announced it will aggregate 525 residential batteries into a virtual power plant. The program will launch in the fall, with the batteries being managed and dispatched to "optimize the use of renewable energy and our grid capabilities."

PGE will study the benefits of the batteries as distributed energy assets. Each system will be between 12 and 16 kW and together form up to 4 MW of dispatchable resources.

Some participating households were offered $5,000 in rebates on battery system purchases, as well as money off their monthly bills.

More: *Energy Storage News*

### Portland Declares Climate Emergency

The Portland City Council last week adopted a climate emergency declaration, acknowledging that the city is in the middle of an environmental crisis and committing to a series of steps to mitigate impacts.

The resolution has more than 30 commitments, including adopting a new target for carbon emissions (50% below what the region's emissions level were in the 1990s) and becoming a net-zero emitter by 2050.

More: *Oregon Public Broadcasting*

## TENNESSEE

### PUC Orders Utilities to Continue to Suspend Service Disconnections

The Public Utility Commission last week ordered utilities to continue to suspend the disconnection of services because of nonpayment until the commission's next meeting on Aug. 10.

The order invites the utilities under the PUC's oversight to file comments on the impact of suspensions to its business operations and any relevant transitional proposals to service cutoffs by July 15.

"To be clear, we recognize that there can be no one-size-fits-all policy that encompasses the entirety of a public utility's operations or the challenges faced by its customers," PUC Chair Robin Morrison said. "So before we move to eliminate and lift the suspension of cutoffs, more information would be of great value to the commission."

More: *Tennessee PUC*

## TEXAS

### Bank of America, Reliant Ink Solar Agreement

Bank of America last week announced its first 10-year structured renewable energy agreement for solar power with Reliant, an NRG Energy company. The deal is part of Bank of America's commitment to purchase 100% of its electricity via renewable sources.

The project will provide electricity through ERCOT to 345 facilities and supply 160 GWh to Bank of America's state operations annually. It is expected to be operational in mid-2022.

More: *Bank of America*

## VIRGINIA

### Blue Wave Climate, Pollution Laws Kick in

A package of environmental bills took effect last week, including one that enacts a Council on Environmental Justice and another that puts the state in the Regional Greenhouse Gas Initiative.

Under HB 1042, the 21-member council was created to advise the governor and General Assembly on "how to better protect low-income communities of color from disproportionate impact of the health dangers of pollution." It will also be charged with integrating environmental justice throughout the state's programs, regulations, policies and procedures.

HB 981 authorized the state's membership in RGGI. The bill also states 45% of the money generated from in-state carbon allowance auctions will be put into a community flood preparedness fund.

More: *Bloomberg Law*

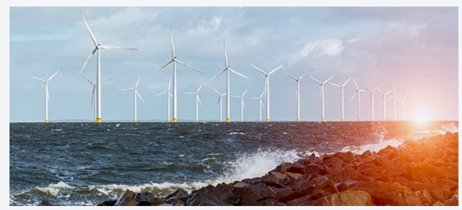
### SCC Delays Natural Gas Pipeline Through Chesapeake

The State Corporation Commission has declined to give the go-ahead for the proposed $346 million Header Improvement Project gas pipeline that would run through Chesapeake, saying Virginia Natural Gas needs to do more legwork on securing financing and environmental justice issues before construction can begin.

Virginia Natural Gas has until Dec. 31 to meet the requirements laid out by the SCC, which include addressing financial concerns and protecting ratepayers from added costs. The project includes three new pipelines totaling 24 miles and three new or expanded gas compressor stations. In Chesapeake, about $24 million would go toward building a compressor station on 6 acres of the existing Gidley Gate Metering/Regulation Station.

More: *The Virginian-Pilot*

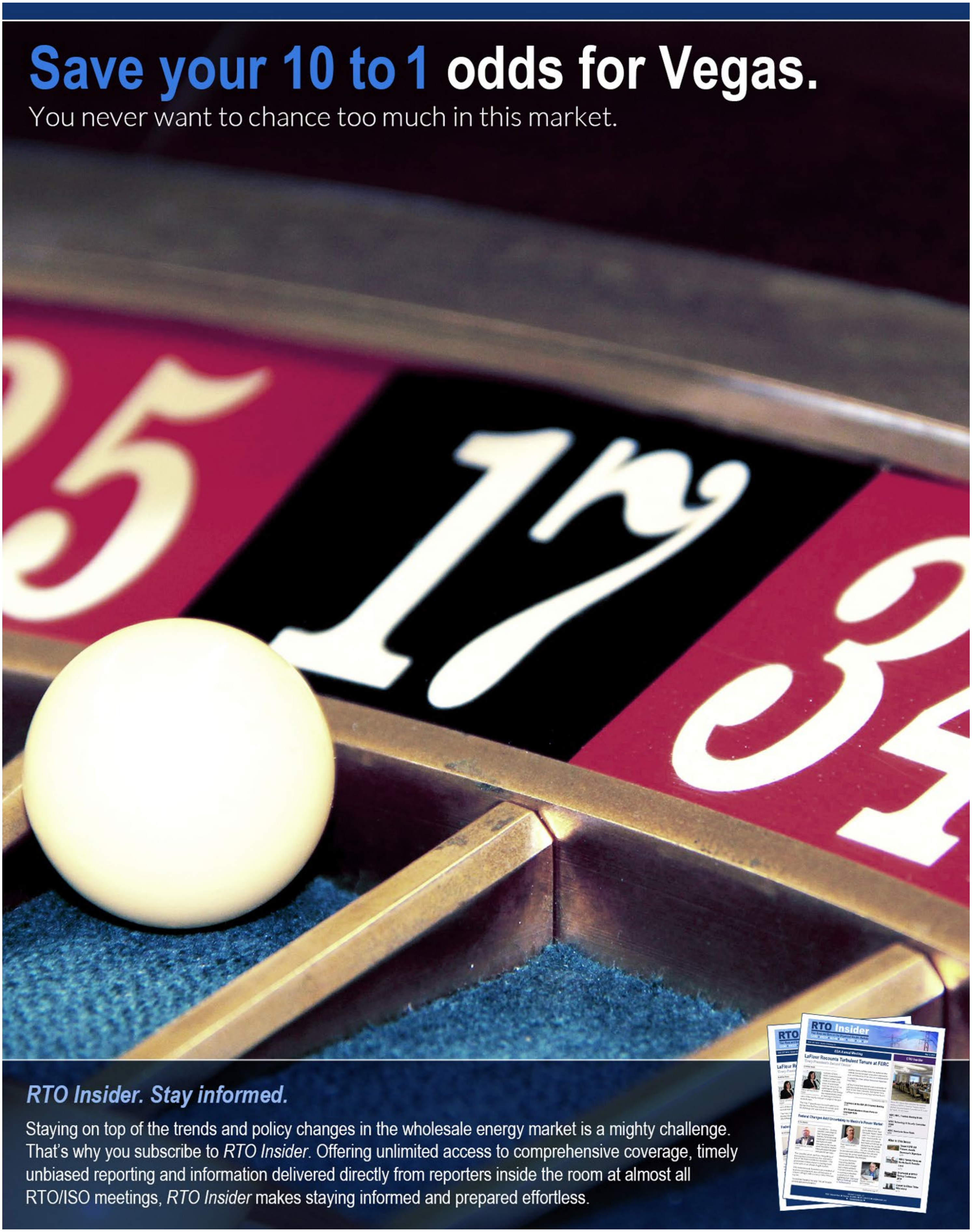
### Second US Offshore Wind Project Finishes Construction



Dominion Energy and Ørsted last week announced they have completed installation of the $300 million Coastal Virginia Offshore Wind pilot, which is the second offshore wind facility ever built in U.S. waters.

Dominion said both 6-MW Siemens Gamesa turbines are in place following the installation of the two monopile foundations. The turbines will undergo testing in the coming weeks before the project is fully energized later this summer. The pilot is the predecessor to the utility's planned 2,600-MW follow-up project at an adjacent project site and is the largest offshore wind farm currently planned in American waters. It is scheduled to begin construction in 2024.

More: *GreenTech Media*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