RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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Reports: Clean Electricity Performance Program Killed by Manchin

By Rich Heidorn Jr.

Democrats' proposed Clean Electricity Performance Program (CEPP) is dead or on life support, doomed by Sen. Joe Manchin's (D-W. Va.) opposition, according to numerous news reports over the weekend.

The CEPP, which would reward utilities that exceed emission reductions of 4% annually and penalize laggards, has been widely *described* as the "linchpin" of President Biden's climate plan. News of its demise, coming just two weeks before the U.N.'s COP26 climate talks in Glasgow, had some environmentalists in despair.

But others said the $150 billion program would be bad policy and insisted its loss would not necessarily doom the Biden administration's pledge to reduce U.S. greenhouse gas emissions to 50% below 2005 levels by 2030. They said efforts to decarbonize the power sector will continue, thanks to federal tax credits and supportive state policies.

"The CEPP is overshadowing the real star proposal": about $300 billion to extend existing tax credits for utilities, commercial businesses and homeowners that use or generate electricity from zero-carbon sources, *The Economist* *wrote*.

CEPP: One-third of Reductions?

An *analysis* this month by *Energy Innovation: Policy and Technology*, an energy and environmental policy firm, said the most powerful emission-reduction provisions in the bipartisan infrastructure bill and the broader legislation Democrats hope to pass on party-line votes (referred to as the "infrastructure bills") "is the combination of clean energy tax credits and the Clean Electricity Performance Program, which drives the power sector to 70 to 85% clean energy."

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IEA Calls on World Leaders to Close Net-zero 'Ambition Gap' (p.14)

FERC Tx Inquiry: Consensus on Need for Change, Discord over Solutions

Wide Support for GETs; Incumbents Seek to Restore ROFR

By Rich Heidorn Jr.

FERC's inquiry into transmission planning and cost allocation prompted a flood of comments this week, most of them agreeing with the commission on the need for changes to aid the transition to a low-carbon grid.

But there was no consensus over whether the commission should eliminate participant funding or create independent transmission monitors. And transmission owners used the docket to call for a restoration of incumbents' right of first refusal to construct upgrades in FERC-approved tariffs.

FERC received more than 165 comments from utilities, independent power producers, state regulators, RTOs and others in response to the Advance Notice of Proposed Rulemaking (*RM21-17*) the commission issued following a bipartisan 4-0 vote in July. In opening the inquiry, FERC acknowledged that Order 1000 has failed to provide interregional expansions to deliver increased renewables and meet the challenge of climate change. (See *FERC Goes Back to the Drawing Board on Tx Planning, Cost Allocation*.)

As is often the case in such dockets, the commission heard many entreaties against a "one-size-fits-all" rulemaking.

"Concerns with the transmission planning and generator interconnection processes are likely to be highly regional in nature," said the American Public Power Association, opposing a "blanket move away from participant funding in regions where it is currently permitted."

Dominion Energy said the commission should continue to acknowledge and respect the differences between RTO and non-RTO regions.

"FERC should refrain from establishing overly

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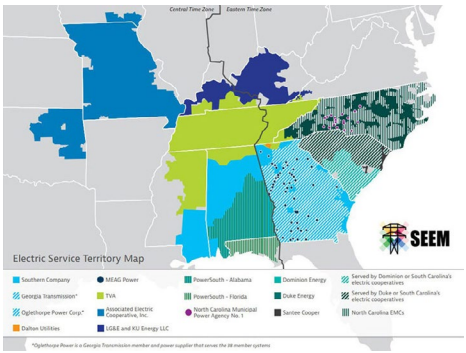
Stakeholders Ask FERC to Support E&AS Market Changes (p.22)

SEEM to Move Ahead, Minus FERC Approval

Deadlocked Commission Means Agreement Effective Oct 12



Map of proposed Southeast Energy Exchange Market | *SEEM*

By Holden Mann

A divided *FERC* means the proposed *Southeast Energy Exchange Market (SEEM)* agreement took effect on Oct. 12, the commission announced Wednesday (*ER21-1111*, *et al.*), bringing relief for the proposal's supporters

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In this week's issue

Counterflow

By Steve Huntoon

Apples and Oysters

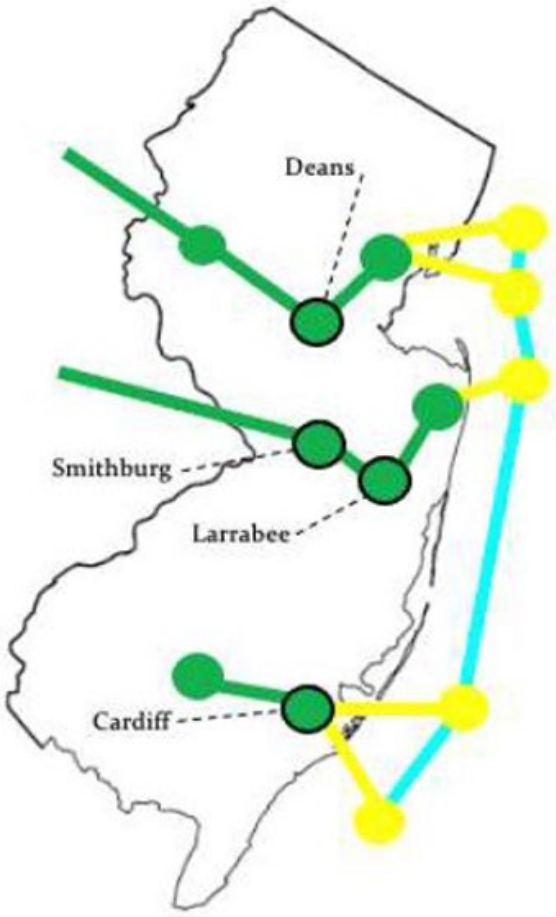
By Steve Huntoon

In my last column[1] I discussed the importance of retaining participant funding for generation interconnection — a long-standing foundational principle in all the RTOs. It ensures economic siting of new generation and thus economic deployment of new resources. It is fundamentally fair as new generation benefits from existing transmission "headroom" paid for by others, just as new generation may create new headroom used by others in the future. I also explained how a study by the ICF consultancy, purporting to support the end of participant funding, actually supports the opposite conclusion. Finally, I showed that FERC's reasoning given in its Advance Notice of Proposed Rulemaking (ANOPR) on transmission planning for ending participant funding had four fatal flaws (*RM21-17*).

Another Day, Another Study

On the eve of the due date for filing comments on the ANOPR another study appeared. This one also paid for by the renewable energy industry, with the Brattle consultancy the lead author. (See *New Tx Study Calls for Holistic Planning Across Regions*.)

I will spare you point-by-point commentary on Brattle's 105 pages (some of which I actually agree with), but I do want to address the study's focus on a recently released PJM offshore wind analysis. This Brattle study, like the ICF study I previously discussed, does *not* undercut the case for participant funding. As I explain in (agonizing) detail below, the crux of the matter is that Brattle uses a number for transmitting offshore wind that does not include the cost of delivering the wind to onshore, inland substations.



A PJM analysis done at the request of the New Jersey Board of Public Utilities assumes that most offshore wind will be interconnected at inland substations, where there are lots of high voltage transmission lines and lots of load to absorb generation. | *NJBPU*

Into the Weeds!

Brattle says individual PJM interconnection studies of offshore wind show network upgrade[2] costs of $6.4 billion to interconnect 15.5 GWs.[3] Per the math Brattle says this is more than $400/kW to interconnect new offshore wind.

Brattle then contrasts that with a recent, single PJM analysis showing network upgrade costs of $3.2 billion to interconnect 17 GWs.[4] Per the math this is $188/kW to interconnect new offshore wind.

Aha! Brattle says. Studying project interconnections individually costs more than double ($400/kW v. $188/kW) than when using a "proactive region-wide study." A poster child for "holistic" planning!

Being a glutton for punishment, I waded through the 59 offshore wind interconnection studies posted on the PJM website,[5] and reviewed the PJM analysis and its history.

Let's Start with New Jersey

The biggest flaw in the Brattle study concerns the New Jersey numbers. There, individual interconnection studies for active (not withdrawn) projects[6] show network upgrade costs of $3.3 billion to interconnect 7.4 GWs. In contrast, the PJM analysis shows network upgrade costs for the three New Jersey transmission owners of $0.4 billion to interconnect 7.6 GWs.

So, you're thinking, $3.3 billion versus $0.4 billion, this holistic study stuff is amazing! But no. The individual studies bring the offshore wind to *coastal* substations, while in the PJM analysis PJM assumes (per direction from the New Jersey Board of Public Utilities) that the bulk of the offshore wind will be interconnected at *inland* substations, shown on the inset map on slide 47 of deck *here*, where there are lots of high voltage transmission lines and lots of load to absorb generation. Thus, few network upgrades are needed to accommodate injections at the inland substations.

But the rub is that you have to get the offshore wind to these inland substations. The PJM analysis includes *zero* cost for that.

How much would it cost to move 5.5 GWs[7] inland, with the added cost of using HVDC transmission instead of HVAC transmission? I have no idea, but NREL says HVDC-HVAC converter stations run about $367 million a copy,[8] and it looks like New Jersey would

Counterflow

By Steve Huntoon

need around six of them. HVDC transmission lines through densely populated New Jersey would be on top of that.

Bottom line, the PJM analysis eliminates almost all network upgrade costs by assuming offshore wind arrives at inland substations at zero cost. This does not mean the PJM analysis is wrong, it means inland injection network upgrade costs cannot be compared with coastal injection network upgrade costs.

Moving On to Virginia/North Carolina

Now that we understand the New Jersey mismatch, the PJM results for other states will make some sense. Starting with Virginia/North Carolina, active individual interconnection studies show upgrade costs of $948 million to interconnect 5.0 GW of offshore wind. That comes to $190/kW.

The single PJM analysis shows transmission owner (Dominion) upgrade costs of $1.9 billion to interconnect 7.8 GWs. That comes to $243/kW — actually more than the individual studies' cost per kW. So much for the Brattle take.

Virginia/North Carolina Case Study for Averting Customer Disaster

Virginia/North Carolina also gives us a great example of how participant funding can avert customer disaster. The project developer proposing 2.4 GWs of injection on the Birdneck-Landstown circuit originally proposed to inject at the Virginia Beach substation. According to the PJM studies, the former costs $736 million in network upgrades and the latter costs $1.9 billion in network upgrades.[9]

In the absence of participant funding, the developer would have had no reason to change the point of injection (which it did a month after receiving the PJM studies for the initial, high-cost point of injection). Customers would have paid more than $1 billion extra in socialized transmission costs. Not good.

And Delaware and Maryland

For its single analysis PJM assumes all 1.6 GWs are injected at Delmarva's Indian River substation. The three active interconnection requests for that substation show upgrade costs of $677 million to interconnect 1.1 GWs.[10] The PJM analysis shows transmission owner upgrade costs of $711 million to interconnect the 1.6 GWs.[11] There is a difference in cost per kW but it can't be meaningful because the Delmarva-only upgrade costs are $180.6 million for the individual studies' 1.1 GWs, and $53.7 million for the PJM analysis of 1.6 GWs. This isn't possible for injections at the same substation assuming all else is equal. So idiosyncrasies in modeling, rather than planning fundamentals, must be the difference.

Wrapping Up

The Brattle's study reliance on a PJM analysis to claim that holistic, regional planning yields much less network upgrade costs than individual interconnection studies is unsound. The cost per kW difference that Brattle relies on comes exclusively from New Jersey offshore wind, where the PJM analysis assumes that offshore wind is brought inland at *zero* cost.

The other states present a mixed picture, as well as a great example of why we don't want developers to be indifferent to network upgrade costs. Which they would be if participant funding were replaced by socialized transmission cost allocation.

A Postscript on Claimed Benefits for Load

Like the ICF study, the Brattle study claims network upgrades can benefit load, citing a PJM slide about congestion relief, etc. Brattle twice uses the word "substantial" in its characterization of the PJM benefits slide, a word that doesn't actually appear on the slide.[12]

But more fundamental to the participant funding subject is that there is no reason to think that uneconomic network upgrades provide more load benefits than economic network upgrades, or somehow contribute extra benefits that would outweigh the extra cost to load. And that's the point.

And a Post-postscript on 'Holistic' Planning

It's a recipe for chaos. Revealing was this passage in a PJM FAQ about the NJBPU solicitation for transmission proposals:[13] "PJM and NJBPU will not provide a numerical weighting or metric for evaluation criteria … Participants are encouraged to provide sufficient responses in their proposal submission to enable PJM and the NJBPU to properly consider all evaluation criteria."

If I might translate, PJM and the NJBPU won't say how they will weigh the many evaluation criteria under this "holistic" approach. Instead, project sponsors must guess what PJM and the NJBPU might end up thinking and provide "sufficient responses" for PJM and the NJBPU to "properly consider all evaluation criteria." If that is the future of transmission planning, we might as well turn everything back to transmission owners' tender mercies. ■

[1] Available here, https://www.energy-counsel.com/docs/participant-funding-and-its-discontents.pdf, and here, https://www.rtoinsider.com/articles/28723-counterflow-participant-funding-discontents.

[2] Network upgrades upgrade the grid – they do not include the cost of direct connection of the project to the nearest substation or transmission line (aka circuit).

[3] https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Planning-for-the-21st-Century-Proven-Practices-that-Increase-Value-and-Reduce-Costs.pdf, pages 4-5.

[4] https://www.pjm.com/-/media/committees-groups/state-commissions/isac/2021/20210729/20210729-isac-presentation.ashx, slide 14.

[5] To replicate my search go to https://pjm.com/planning/services-requests/interconnection-queues, then in the "Fuel" column select "Offshore Wind." fifty-nine projects should show up.

[6] After doing the search in the preceding footnote you can select status of "Active." Then sort by "State" and scroll down to New Jersey.

[7] This is the total inland injections, at the Deans, Larrabee and Smithburg substations.

[8] https://www.eia.gov/analysis/studies/electricity/hvdctransmission/pdf/transmission.pdf, page 23.

[9] Project queues AE2-122, AE2-123 and AE2-124 for the Birdneck-Landstown circuit, and AE1-065, AE1-066 and AE1-067 for the Virginia Beach substation.

[10] Project queues AB1-056, AF2-193 and AF2-194.

[11] Adding Delmarva, BGE and PECO network upgrades.

[12] https://www.pjm.com/-/media/committees-groups/state-commissions/isac/2021/20210729/20210729-isac-presentation.ashx, slide 24.

[13] https://www.pjm.com/-/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2021-saa-proposal-window-to-support-nj-osw/2021-nj-osw-window-faq.ashx (General Proposal Window Questions and Answers).

American Clean Power Association's Offshore WINDPOWER 2021

Environmental Justice Communities Leading OSW, Advocate Says

Opportunities for OSW Workforce Training, Education Needed at All Employment Levels

By Emily Hayes

BOSTON — Environmental justice communities are already doing the work needed to make renewable energy industries like offshore wind equitable in their workforce and community benefits, according to Elizabeth Yeampierre, co-chair of the Climate Justice Alliance.

"We have questions; we have solutions; and we have concerns," Yeampierre said during a panel on environmental justice in the development of the U.S. OSW industry. "Anyone who is coming into the sector needs to be able to support that and not manage our expectations or give us a voice — we have a voice, and we are leading this work nationally."

The panel on Thursday was part of the American Clean Power Association's Offshore WINDPOWER 2021 conference, held in Boston last week. It brought together officials from the federal and state level, as well as environmental justice advocates and a developer to discuss how to ensure frontline communities are equitably included in workforce development, training and education recruitment.

Developers should advise environmental justice communities on financing, costs and technical construction work, because "we're leading this movement," Yeampierre said, herself a leader from a community on the frontline of climate change in Brooklyn, N.Y. "We are not here to advise you."

Conversations on how to equitably include environmental justice communities are not just about the disparate impacts of the energy industry on people of color and low-income workers, but a matter of allowing people in these communities to speak for themselves, she added.

"Really, the national initiatives and the state initiatives are being shaped by the work that is being done in vulnerable communities like ours," Yeampierre said.

For example, New York City recently invested in the South Brooklyn Marine Terminal, a two-acre site on the Bay Ridge Channel, to make a national staging and assembly site for OSW. The terminal will be operated by Equinor, developer of the 1,260-MW Empire Wind project.

The company said it will establish a $5 million fund to ensure New Yorkers from low-income communities and communities of color benefit from the new investment, including the creation of at least 6,000 local jobs, because of advocacy from leaders like Yeampierre.

"Success for environmental justice communities equals having access to training, workforce development and education in all levels of employment," she said. "Our communities can't be boxed into bonuses or only have access to minimum wage or entry-level jobs."

From a developer perspective, states have been leading the way with commitments to include underserved communities, said Nancy Sopko, head of external affairs at US Wind.

"There is a very strong commitment from the state to include local content in our OSW projects" to bring on more members of minority-owned businesses, women-owned businesses, veteran-owned businesses and disabled persons-owned businesses in the state, Sopko said,

But it is important that the jobs given to these businesses are good jobs, said Crystal Pruitt, deputy director of the Office of Clean Energy Equity for the New Jersey Board of Public Utilities.

People of color and women often receive "little cheap jobs and simple jobs that don't mean anything and companies just mark it off," Pruitt said. "Look at the jobs you're giving these communities and these contractors and recognize that they need to be lifted up and become prime as well." ■

Nancy Sopko of US Wind discusses with moderator Damian Bednarz, of EnBW North America, how community leaders in Maryland are leading the way for equitably including environmental justice communities in OSW workforce development at the American Clean Power Association's Offshore WINDPOWER 2021 conference. | *© RTO Insider LLC*

American Clean Power Association's Offshore WINDPOWER 2021

OSW Grid Strategy Must Extend Beyond Current Proposals, Utility Says

By Emily Hayes

BOSTON — Offshore wind developers need to think on a larger scale than current projects in the pipeline when it comes to transmission planning, according to Nabil Hitti, director of U.S. business development for National Grid.

"The existing plans and sizes are manageable, and the question is, 'Can we go bigger?'" Hitti said at a panel for the American Clean Power Association's Offshore WINDPOWER 2021 conference on Wednesday.

The U.S. Bureau of Ocean Energy Management this week set a goal to hold up to seven new offshore lease sales by 2025 to meet the Biden administration's goal for 30 GW of OSW by 2030.

Coastal states are already facing the challenge of how to integrate existing OSW proposals into the transmission network, along with how to increase transmission capacity in general to "unlock the potential of renewables across the nation," Hitti said.

BOEM is reviewing nine projects following its approval of the Vineyard Wind project off the coast of Massachusetts earlier this year.

Ocean Wind, the largest project under review with the agency, is expected to have a total capacity of 1,100 MW.

"PJM has been very helpful to us in trying to come up with the transmission that is going to provide the maximum rate of return for ratepayers," Upendra Chivukula, New Jersey Board of Public Utilities commissioner, said during the panel discussion.

But New Jersey is at the forefront of issues with OSW interconnection, including establishing charges and costs, Chivukula said.

"Currently the planning system is fragmented, I think, due to transmission owners having incentives to construct and recover costs from transmission projects with little or no oversight," he said. Those costs are then passed to ratepayers.

When developers approach state agencies for OSW renewable energy certificates, the "largest component of risk is associated with transmission costs," said Tim Burdis, senior manager of policy solutions for PJM.

"You can quantify a lot of the other costs, but you don't necessarily have specificity around what are going to be the upgrade costs that an ISO or RTO might be sticking with the bill," Burdis said.

Transmission upgrade and replacement decisions in anticipation of a skyrocketing OSW industry need to be made now to save money and time on integrating the renewable resource, instead of "having to make a minimal upgrade and then come back later and make a bigger upgrade for OSW that wants to come on to the system," Burdis said. "The state of public policy says it is going to be on in 10 years." ■

Renewable energy developers Matthew Picardi of Shell (center) and Nabil Hitti of National Grid (right) discuss OSW challenges with moderator Adrienne Downey, of NYSERDA. | *© RTO Insider*

American Clean Power Association's Offshore WINDPOWER 2021

Offshore WINDPOWER 2021 Conference Briefs

Building a Better OSW Permitting Process

BOSTON — As part of series of opening keynotes at the American Clean Power Association's Offshore WINDPOWER 2021 conference, U.S. Secretary of the Interior Deb Haaland announced plans for the Bureau of Ocean Energy Management to potentially hold up to *seven new OSW lease sales by 2025* in the Gulf of Maine, New York Bight, Central Atlantic and the Gulf of Mexico, in addition to the Carolinas, California and Oregon.

During a subsequent panel on permitting improvements, BOEM Renewable Energy Program Manager James Bennett said Haaland's announcement represents "a path forward."

"It does identify where we're going and what we're doing," Bennett said. "This is not the first time we have attempted to put together and lay out a path forward, but it is the first time that we have been successful in being able to share with the public and specifically identify when lease sales are targeted for the near future."

Massachusetts has targeted net-zero emissions by 2050, and at least 15 GW of OSW are needed, according to the state's *Decarbonization Roadmap*. Energy and Environmental Affairs Secretary Kathleen Theoharides said that forward momentum on new lease areas "is a great, exciting announcement that probably should have received a lot more clapping from this audience."

"It's another piece of the puzzle to this whole question," Theoharides said.

The Federal Permitting Improvement Steering Council (FIPSC) helps fit the puzzle pieces by overseeing interagency coordination and process improvements. With the Biden administration using a whole-of-government approach to deploy 30 GW of OSW by 2030, FIPSC Executive Director Christine Harada said from an efficiency perspective, "there's a lot of work that we need to do within a very limited amount of time."

Project uncertainty is challenging some of the agencies regarding how to permit something or how to evaluate the impacts under their statutory mandates, according to Scott Lundin, head of U.S. permitting and environmental affairs at Equinor. For example, Lundin said the Block Island Wind Farm began operations in 2016 with five 6-MW turbines, but General Electric announced that its turbines can now generate 14 MW of power.

"There's a concern and a risk that alternatives get defined that are not technically, commercially, environmentally feasible," Lundin said. "I think the opportunity for the developers to help inform and shape perspectives of these different agencies about the value and the need to bring these products to commercial operation is something that we're very interested in facilitating whenever possible."

Theoharides on Baker Announcement

After the permitting panel's conclusion, Theoharides told *RTO Insider* that the *announcement of legislation* by Massachusetts Gov. Charlie Baker (R), which would create a $750 million clean energy investment fund and refine the current OSW procurement process, is "significant."

"What it will open up for us here in Massachusetts is a chance to ensure that not only are we aggressively pursuing our net-zero targets, but we are leading the industry to design the solutions and then to retain those jobs right here in Massachusetts and in the Northeast," Theoharides said.

The main change to the OSW procurement process would be the transfer of authority to select the winning bidder from state's electric distribution companies like Eversource and National Grid to the Department of Energy Resources. However, EDCs would remain participants in the evaluation and provide technical advice to the department.

Theoharides said that taking the EDCs "out of the game" of choosing which company will win the bid makes procurements "more efficient" and "more objective process overall."

Baker's legislation comes on the heels of a plan by his administration to also direct $900 million in federal aid from the American Rescue Plan Act toward vital energy and environmental initiatives, including $100 million to invest in port infrastructure to support OSW. Theoharides said the $100 million would "kick off" port infrastructure work, and the state would look to leverage additional private investments.

Markey: Politics Hinder Renewable Energy Progress

U.S. Sen. Ed Markey (D-Mass.) said during an interview Thursday that the only thing stopping the progress on renewable energy sources like OSW is "politics and not technology."

"If we didn't have political opposition that was in place, the technology would have evolved much more quickly," Markey said.

The target of 30 GW of OSW by 2030 set earlier this year is "modest," according to Markey. However, he also thinks political opposition will be funded by the fossil fuel industry, especially at the ballot box.

"The fossil fuel industry is going to try to take the 2024 election, make it a referendum, bring back a gang that is tied to the fossil fuel generation strategy," Markey said.

Markey *introduced a bill* in September that would create a 30% investment tax credit for U.S. manufacturers to produce qualified OSW components and dedicated vessels. "We've tailored the solutions to the exact needs of the industry to get the policies that fit to reduce the high capital costs that manufacturers face," Markey said. ■

— Jason York

Massachusetts Energy and Environmental Affairs Secretary Kathleen Theoharides (center) speaks on a panel with Kevin Ewing of Bracewell (left) and Scott Lundin of Equinor during the American Clean Power Association's Offshore WINDPOWER 2021 conference last week in Boston. | *© RTO Insider LLC*

American Clean Power Association's Offshore WINDPOWER 2021

OSW Vessel Supply a 'Generational Opportunity,' Expert Says

By Jason York

BOSTON — To meet the Biden administration's 30-GW offshore wind goal by 2030, private investment coupled with government-backed financing is needed to spur construction of wind turbine installation vessels (WTIV), which carry a price tag of $500 million.

From the standpoint of the U.S. maritime industry, OSW is a "generational opportunity," said Jennifer Carpenter, CEO of the American Waterways Operators, during the American Clean Power Association's Offshore WINDPOWER 2021 conference on Thursday.

Multiple things can be done to "develop the supply of vessels" to serve the lifecycle of an OSW project, "from a survey, all the way on through construction development, eventual decommissioning," she said.

"The first thing I would say is let's not make it overly complicated to stimulate supply," Carpenter said. "We have to focus on demand. It is not surprising that we do not have a fleet of vessels sitting on the proverbial shelf waiting to serve an industry that has not yet existed in this country because we're doing something new."

Because the Jones Act enjoys strong bipartisan support in Congress and from President Biden, Carpenter added, it "helps foster the certainty that we need to make investments" in WTIVs and other vessels. The Jones Act can be waived under tightly controlled circumstances, such as national defense, and there are no qualified U.S. vessels to meet that need, according to Carpenter.

Dominion Energy is currently constructing a Jones Act-compliant WTIV, which will be completed in 2023. However, U.S. developers will also have to rely on European-flagged jack-up vessels if any steel goes in the water in the near term. There are nine WTIVs available globally that can install turbines greater than 10 MW, and of those, only two of them can install turbines in the 12-MW-plus category. (See *US Must Watch Europe's OSW Supply Constraints, Analyst Says*.)

Karl Humberson, director of construction projects for Dominion, said during the conference that he hopes construction of the WTIV provides the OSW industry "a level of certainty" that investments such as this are "going to help everybody else."

Constructing a WTIV, he said, is not part of Dominion's core business, but when the company looked at the puzzle pieces for OSW to determine "which ones are missing," Dominion took "some risks."

"We're a little bit different. We are an owner-operator of a wind farm, so we have a little bit of certainty saying there's a project here that we're going after," Humberson said. "That helped us make some decisions related to the WTIV. … We think it is the right way to build offshore wind, and that's why we made these investments."

While heavy lift vessels "get a lot of press" because of the significant investment, Troy Patton, COO for Ørsted Offshore North America, said he was struck by how many additional vessels are needed on an OSW project. Construction for a project off the coast Grimsby, England, he said, required upward of 50 vessels to deliver equipment and personnel to the wind farm.

The Title XI Federal Ship Financing Program will pay up to 87.5% of the cost for certain vessel classes and shipyards, according to David Gilmore, director of the Office of Marine Financing at the United States Maritime Administration. That payment can cover the construction of new vessels, reconfiguring vessels and modernization of shipyard facilities. Applicants for this program must meet financial requirements. There are also loan guarantee programs for onshore wind, which could be expanded to OSW projects and a capital construction fund with tax deferrals.

"There's a lot of opportunity out there," Humberson said. ■

Panelists speaking during a session on offshore wind vessels at the American Clean Power Association's Offshore WINDPOWER 2021 conference in Boston last week. From left: Claire Richer, American Clean Power Association; Troy Patton, Ørsted Offshore North America; Jennifer Carpenter; American Waterways Operators; Bruce Harland, Crowley Wind Services; and Ketil Arvesen, Fred. Olsen. | © *RTO Insider*

American Clean Power Association's Offshore WINDPOWER 2021

Report: Planned OSW Assembly Ports Will Only Meet Half of Demand

Assembly, Housing and Deployment Ports the Hardest to Site in the US

By Emily Hayes

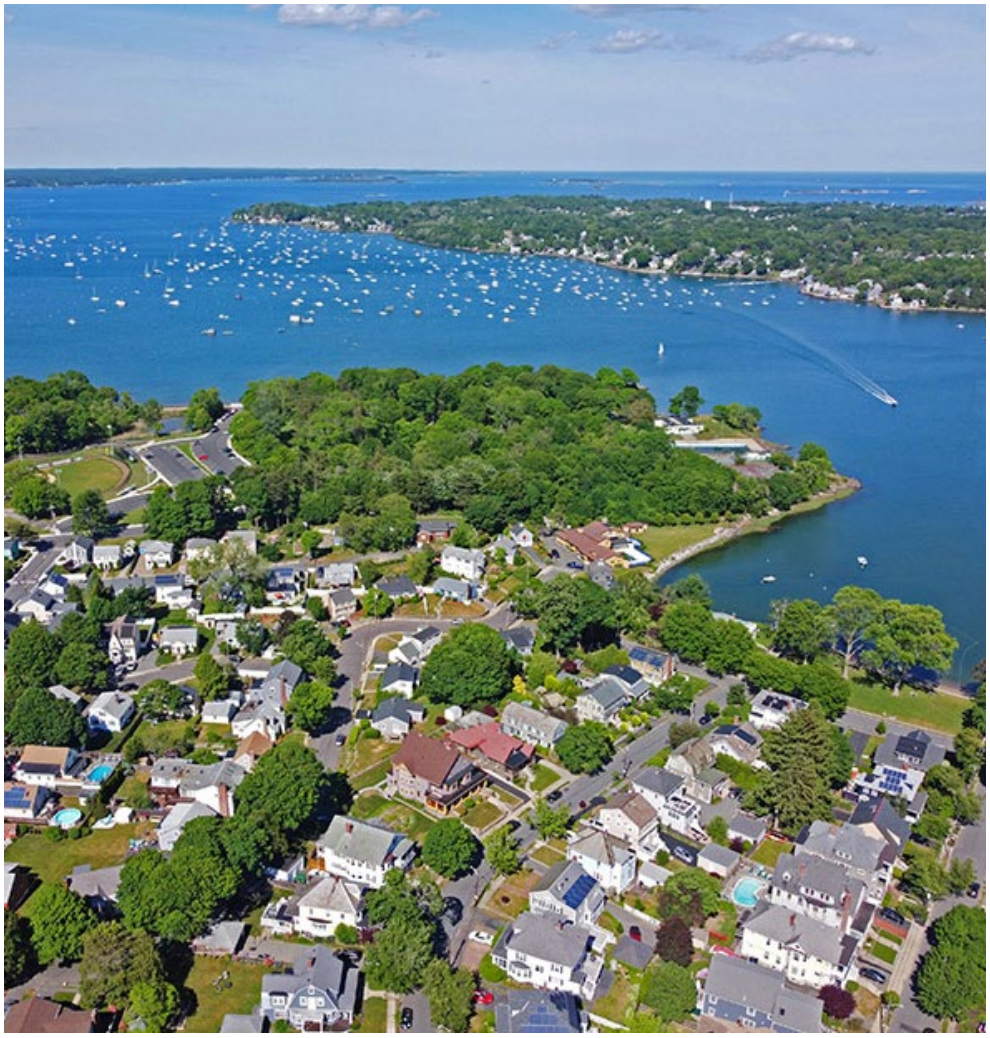
BOSTON — The development of marshalling areas is posing a critical infrastructure challenge for the offshore wind industry, hindering state and federal clean energy goals.

As it currently stands, port marshalling area can only meet half of the potential OSW demand, according to an assessment of OSW port infrastructure and deployment methods conducted by energy policy analyst Sara Parkison, a Ph.D. candidate at the University of Delaware.

Parkison presented her findings at the American Clean Power Association's Offshore WINDPOWER 2021 conference in Boston on Thursday, highlighting the need for "forward-looking port and vessel designs that will allow for more efficient and cost-effective deployment."

Architectural and engineering advancements in design will be necessary to meet the Biden administration's plans for deploying 30 GW of OSW by 2030.

But marshalling ports, or large waterside sites with the acreage and weight-carrying capacity needed to assemble, store and deploy OSW wind turbines are difficult to site. Viable land along the East Coast is often already developed as lucrative residential property, Parkison said.



Vineyard Wind created a partnership with the city of Salem, Mass., to turn an area of Salem Harbor into an offshore wind port with no height or width restrictions that inhibit assembling, storing or deploying turbines. | *Shutterstock*

A 1-GW project can use up to 54 acres of space over two years, according to the report.

Other viable areas may not have the overhead access from port to sea to transport 12-MW and 15-MW turbines or channels deep enough for the vessels that carry them out to sea. Much of the remaining undeveloped land is protected for conservation, Parkison said.

Existing marshalling ports in Europe designed for the mass deployment of OSW turbines are much larger than the collection of smaller ports in the U.S. currently designated for the same purpose. The total area of the top three European marshalling ports are three times the size of all U.S. ports.

The U.S. could build a large port like the ones in Europe with the right amount of investment, Parkison said.

"But we need to build where we can, even if it is multiple small ports," she said.

U.S. ports will also need to develop better ways of storing the components so they use up less room, said Jay Borkland, board chair of the Business Network for Offshore Wind, in a panel discussion.

Tower sections will have to be stored closer together and blades will have to be stacked tighter in the U.S. ports than the European ports, Borkland said.

"There is also a huge need for funding specifically for port development," he said.

The Biden administration's 30-GW goal will spur $12 billion in capital investment in OSW annually, including up to $500 million in port upgrades.

Marshalling ports are more likely to qualify for federal funding if developers work with state departments of transportation and improve ports and the efficiency of any freight coming in and out of the area, said Travis Black, team lead of port development and intermodal planning for the Maritime Administration under the U.S. Department of Transportation.

"The executive order for tackling the climate crisis at home and abroad has really extended opportunities for the federal government to use the climate action plan so the states, regions and local governments ... can look at the renewable supply chain" for funding opportunities, Black said. ■

American Clean Power Association's Offshore WINDPOWER 2021

OSW Developers See Robust Interest from Lenders

Financing on 1st Commercial-scale Project Now Complete

By Jason York

Offshore wind developers speak about financing during a panel at the American Clean Power Association's Offshore WINDPOWER 2021 conference in Boston last week. From left, Justin Johns, Mayflower Wind; Joris Veldhoven, Atlantic Shores; Álvaro Ortega Sebastián, Vineyard Wind; and Keith Martin, Norton Rose Fulbright. | *© RTO Insider LLC*

BOSTON — When Avangrid Renewables and Copenhagen Infrastructure Partners began talking to banks about financing their *Vineyard Wind* project back in 2019, more than 60 institutions took the company's calls.

"We explored all the possibilities, and we saw so much interest," CFO Álvaro Ortega Sebastián said.

The lenders' ardor was not dampened when the Trump administration, also in 2019, postponed Vineyard Wind's final environmental impact statement to conduct an expanded analysis of "cumulative impacts" from the multiple offshore projects proposed for New England.

The 800-MW project, 15 miles off the coast of Martha's Vineyard, eventually narrowed the group of banks to nine. When Vineyard Wind wanted to close this year, the lineup was intact, Sebastián told the American Clean Power Association's Offshore WINDPOWER 2021 conference last week.

"We came back in 2021 with the same group just to give them the opportunity to come up to the market with us at the same [interest rates and other terms] that we thought we should go out with, and they were all able to be there," Sebastián said.

In September, Vineyard Wind I became the first commercial-scale offshore wind project in the U.S. to achieve financial close, having raised approximately $2.3 billion in construction and term loan financing from nine banks.

While developers still face challenges in financing OSW projects, lenders are eager to get involved, Sebastián and other speakers told the conference.

Atlantic Shores is further back in the development cycle than Vineyard Wind I. In July, it was awarded a contract by the New Jersey Board of Public Utilities to develop 1,510 MW in OSW energy. A joint venture between EDF Renewables North America and Shell New Energies US, its lease area is located approximately 10-20 miles off the coast of New Jersey between Atlantic City and Barnegat Light.

Joris Veldhoven, the company's commercial and finance director, told the conference the company would explore equity financing as well as "various forms of debt," and export credit agencies — which provide loans, loan guarantees and insurance to promote exports — over the next two-plus years.

Given that Vineyard Wind encountered a situation where it had to stop and start again, Sebastián said by beginning the process with the banks in 2019, it was able "to reduce most of the work" as it moved forward this year.

"There's a lot of back and forth between all the parties involved to negotiate the term price, so the earlier you start, the better," Sebastián said. "But not too early because things can change over time."

Mayflower Wind is developing a lease area 30 miles south of Martha's Vineyard and 20 miles south of Nantucket that it hopes will generate 2,000 MW by the mid-2020s. It is owned by Shell and Ocean Winds, a joint venture by EDP Renewables and ENGIE.

CFO Justin Johns said the companies' balance sheets and existing banking relationships "gives us a lot of flexibility as to when and how we execute.

"I would expect that we're going to use non-recourse project financing similar to how we've done in Europe, and that will involve working to achieve the most competitive terms in the market," Johns said. Non-recourse debt, such as a typical home mortgage, is secured by collateral; lenders cannot go after the borrower's other assets in the event of a default.

OSW projects also currently qualify for an investment tax credit of 30% as long as construction starts by the end of 2025. U.S. Sen. Ed Markey (D-Mass.) *introduced a bill* in September that would create a 30% investment tax credit for American manufacturers to produce qualified OSW components and dedicated vessels. There would also be production tax credits for select OSW components to "prevent bottlenecks" in the supply chain. (See related story, *Offshore WINDPOWER 2021 Conference Briefs: Oct 13-14, 2021*.)

Markey's legislation could get folded into the budget reconciliation bill Democrats are trying to push through Congress. However, Johns said any legislation passed could be a net benefit to the OSW industry if it accounts for all the variables, including the industry's relative immaturity.

"It depends, but it should be a net benefit if it's structured right with a view for offshore wind in recognition of where we are with the supply chain," Johns said. "It needs to recognize U.S. offshore wind is at a much earlier stage. It depends on how that bill is implemented at the agency level. There definitely is potential there, but it needs to be done right." ■

EBA 2021 Mid-Year Forum

EBA Panel Discusses Management and Mitigation of Cybersecurity Risks

By Jason York

The complexity and velocity of cyberattacks, coupled with the volume of vulnerabilities exploited by increasingly sophisticated bad actors, make managing and mitigating cybersecurity risks for critical energy infrastructure a staggering challenge.

Speaking on a panel at the Energy Bar Association's Mid-Year Energy Forum on Oct 12, Manny Cancel, senior vice president at NERC and CEO of the Electricity Information Sharing and Analysis Center, said that approximately 10 years ago, the *National Vulnerability Database* had about 3,000 vulnerabilities "across a whole year."

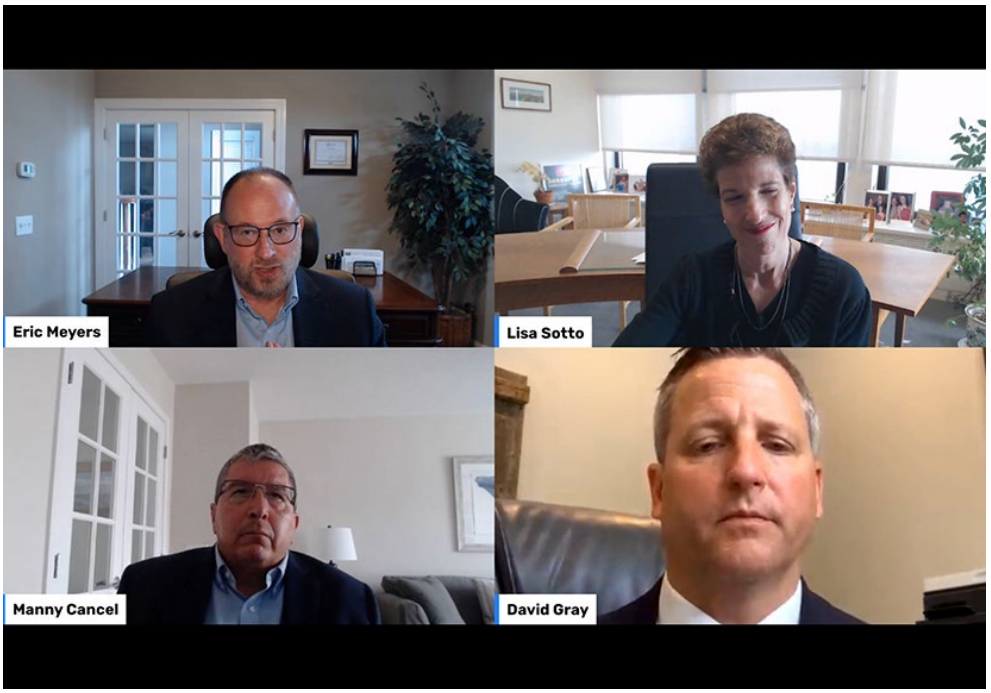
"We're about 21,000 vulnerabilities projected in 2021, and keeping pace with that is just overwhelming," Cancel said. "How the [energy] industry evolves to focus on priorities is going to be a challenge going forward, and we all know that unpatched vulnerabilities are a leading cause of breaches."

One such breach was the ransomware attack on the Colonial Pipeline in May, which crippled 5,500 miles of pipeline that supplies the eastern U.S. with gasoline, diesel and other fuel products. It was an unforgettable day for David Gray, vice president and general counsel for the company. A ransom note appeared on a computer screen in the control room. Gray said the initial reaction was, "Are we sure this is a legitimate threat?"

"You quickly discover that one of the things that are most precious in an event like this is time," Gray said.

In trying to assess whether the attack came from a state-sponsored or non-state entity, Gray said there was "enough uncertainty" to shut down the pipeline and "quickly pivot into notification" once it was determined it was a criminal act. Colonial called the FBI "almost immediately," Gray said, and that helped with the recovery of the ransom it ultimately decided to pay.

Eric Meyers, vice president and chief information security officer for the New York Power Authority, said he has been in the cybersecurity industry long enough to remember when the worst threats were people sending chain emails and infected floppy disks. Now, it is phishing emails and inserting malicious code into websites by state and non-state actors alike.



Clockwise from top left: Eric Meyers, New York Power Authority; Lisa Sotto, Hunton Andrews Kurth; David Gray, Colonial Pipeline; and Manny Cancel, NERC | *Energy Bar Association*

"What used to be the unique domain of some of these well funded state-sponsored actors who invested tremendous amounts of resources in developing those techniques are now out there for anyone to get access to on the web, and even more so, some enterprising entrepreneurs have taken those capabilities and wrapped them up into for-profit services," Meyers said. "Then anybody with very little technical skill can go out there on the dark web, sign up for and launch an attack on anybody. That's acting like a true force multiplier, drastically expanding the scope."

Dan Sutherland, CISA | *Energy Bar Association*

During a keynote speech that preceded the panel, Dan Sutherland, chief counsel for the federal Cybersecurity and Infrastructure Agency (CISA), said that the Colonial attack "sparked" conversation inside and outside the government centered on incident reporting. According to Sutherland, there is legislation under consideration on Capitol Hill that would mandate incident reporting to CISA. He said that is a "direct result" of the Colonial Pipeline incident as Congress felt that it was not reported in a "timely" manner.

The Transportation Security Administration also issued two security directives for owners and operators of critical pipelines in the aftermath of Colonial, which is the first time they have "really exercised their muscles in terms of regulating the pipeline industry," added Sutherland.

TSA required owners and operators to "report confirmed and potential cybersecurity incidents" to CISA. They also needed to appoint a cybersecurity coordinator to serve as a single point of contact with federal officials 24/7, review their current cybersecurity practices, and report to TSA and CISA any cyber risks identified along with related mitigation measures. Additional requirements, developed alongside CISA, mandated implementing "specific mitigation measures" to protect against ransomware and other threats to information technology and operational technology systems; contingency and recovery plans; and a review of cybersecurity architecture design review. (See *TSA Issues New Pipeline Cybersecurity Requirements*.)

Cancel commended Colonial for its "transparency" and managing "an incredibly complex issue." Still, there are a lot of "disruptive technologies" that require time to design their security, which should be done ahead of installation, not after it, he said. ■

EBA 2021 Mid-Year Forum

Overheard at EBA's 2021 Mid-Year Forum

The Energy Bar Association last week once again gathered online, this time for its annual Mid-Year Forum, to discuss carbon capture, environmental justice and electric vehicle infrastructure.

Dan Sutherland, chief counsel for the Cybersecurity and Infrastructure Security Agency, kicked off the two-day event Oct. 12 with a keynote speech and discussion, followed by a panel on cybersecurity risks for the energy industry. (See related story, *EBA Panel Discusses Management and Mitigation of Cybersecurity Risks*.) But the first day also featured two panels on transmission, with one on FERC's Advance Notice of Proposed Rulemaking (ANOPR) into planning and cost allocation, and another focusing on interregional coordination and operations.

Here's some of what we heard.

A New Order Needed?

The first transmission panel focused on FERC's ANOPR, which sought comments on possible changes to its rules on transmission planning and generator interconnection (*RM21-17*). Coincidentally, the session took place on the day comments were due; about 170 companies and groups weighed in. (See related story, *FERC Tx Inquiry: Consensus on Need for Change, Discord Over Solutions*.)

The EBA discussion was a microcosm of the debates that played out through those comments.

Moderator Larry Gasteiger, executive director of WIRES, slyly posed "a simple question" for the panel to answer: Is transmission planning working?

Kari Valley, managing senior corporate counsel for MISO, returned a definitive "yes," though she admitted that there is room for improvement. "We're always looking at where we can address the issues being presented today and the issues that we see in the future," she said, pointing to the RTO's past success with its Multi-Value Project portfolio and its effort to address the massive influx of renewables with its long-range transmission plan.

Sara Weinberg, senior counsel for Dominion Energy, disagreed. "Fundamentally, the regulatory paradigm that we have in place for both transmission planning and generator interconnection is flawed," she said. "It's just antiquated. And it's obviously not in line with the things that we need to be doing right now to move to a cleaner energy future."

Weinberg noted that Dominion serves load in both RTO and non-RTO footprints and said transmission planners work reactively, building transmission to interconnect resources that are in interconnection queues, rather than "looking at everything in a holistic fashion."

Cynthia Bogorad, a partner at Spiegel & McDiarmid, said she would be filing comments later that day for her client, the Transmission Access Policy Study Group (TAPS). Echoing many comments in the FERC docket — not just TAPS' — Bogorad said that "a more holistic approach, while it sounds good, has its own problems [that] we're going to have to tackle. One is [that] a one-size-fits-all approach is not going to be the answer."

Clockwise from top left: Rob Gramlich, Grid Strategies; Cynthia Bogorad, Spiegel & McDiarmid; Larry Gasteiger, WIRES; Sara Weinberg, Dominion Energy; and Kari Valley, MISO | *EBA*

EBA 2021 Mid-Year Forum

Rob Gramlich, president of Grid Strategies and eternal optimist for improved transmission planning policy, was upbeat as he gave a presentation on the history of FERC's efforts regarding the issue and his organization's proposal. One of his slides listed the commission's orders regarding transmission and interconnection: 888 (1996), 2000 (1999), 890 (2007) and 1000 (2011). The last bullet listed "??? (2022?)."

Western Independence and Incrementalism

Jennifer Chen, president of consultancy *ReGrid* and moderator of the second panel, began by thanking attendees for joining "even though your FERC transmission ANOPR comments are due today before 5 p.m." Her session also provided a miniature version of recent discussions, in this case those among Western energy organizations and state legislatures. (See related story, *Talk of Western RTO Intensifies*.)

"There's a lot going on in the West," acknowledged Sarah Edmonds, director of transmission and market services for Portland General Electric. "It's very easy at times, especially for an observer from the outside, to ask, 'Why don't they just do an RTO? Why do they have to do this very unique, incremental approach?' … Our last 20-year-plus of history is marked by the tombstones of several failed attempts in the RTO space."

There are many reasons for these failures, but "it's fundamentally been about trust and control," said Edmonds, whose office was adorned with a painting of two horseback riders riding along a dirt trail.

"There's a deeply ingrained Western culture of self-determination and independence. We have a long tradition of operating our own balancing authority areas … of relying on ourselves and feeling like, 'We know our systems best, and we know how to flex our systems to keep the lights on for our customers.'"

CAISO's Western Energy Imbalance Market began eroding utilities' stubbornness, she said. With Bonneville Power Administration's entry into the market next year, more than 80% of WECC (which covers the entire Western Interconnection except for Alberta) will be served by the EIM.

Edmonds also spoke about the unique challenges to building transmission in the West, including wide areas of tribal land and endangered species habitat. "There's a lot of trepidation in Western hearts, minds and wallets about what transmission cost allocation could mean to customers. This is why I think it's been one of the hardest things to solve."

David Patton — whose firm Potomac Economics serves as market monitor for ERCOT, ISO-NE, MISO and NYISO — said his primary concern was that grid operators "don't fully use the transmission that we have today." Many transmission owners don't use ambient-adjusted or dynamic line ratings to increase capacity as conditions change and "don't provide appropriate emergency ratings, which basically means that the system can be more congested than it needs to be, and it can cause you to believe that high-voltage transmission is more valuable than it actually is."

But "in certain places, especially places [where] the wind is just exploding" — such as SPP, whose director of systems operations, C.J. Brown, nodded along as Patton spoke — "high-voltage facilities are going to be the most economical," Patton said.

Brown responded by *quoting* MISO CEO John Bear: "'If you like renewables, you better like transmission.'" ■

— Michael Brooks

Clockwise from top left: Jennifer Chen, ReGrid; Sarah Edmonds, PGE; David Patton, Potomac Economics; and C.J. Brown, SPP | *EBA*

FERC/Federal News

IEA Calls on World Leaders to Close Net-zero 'Ambition Gap'

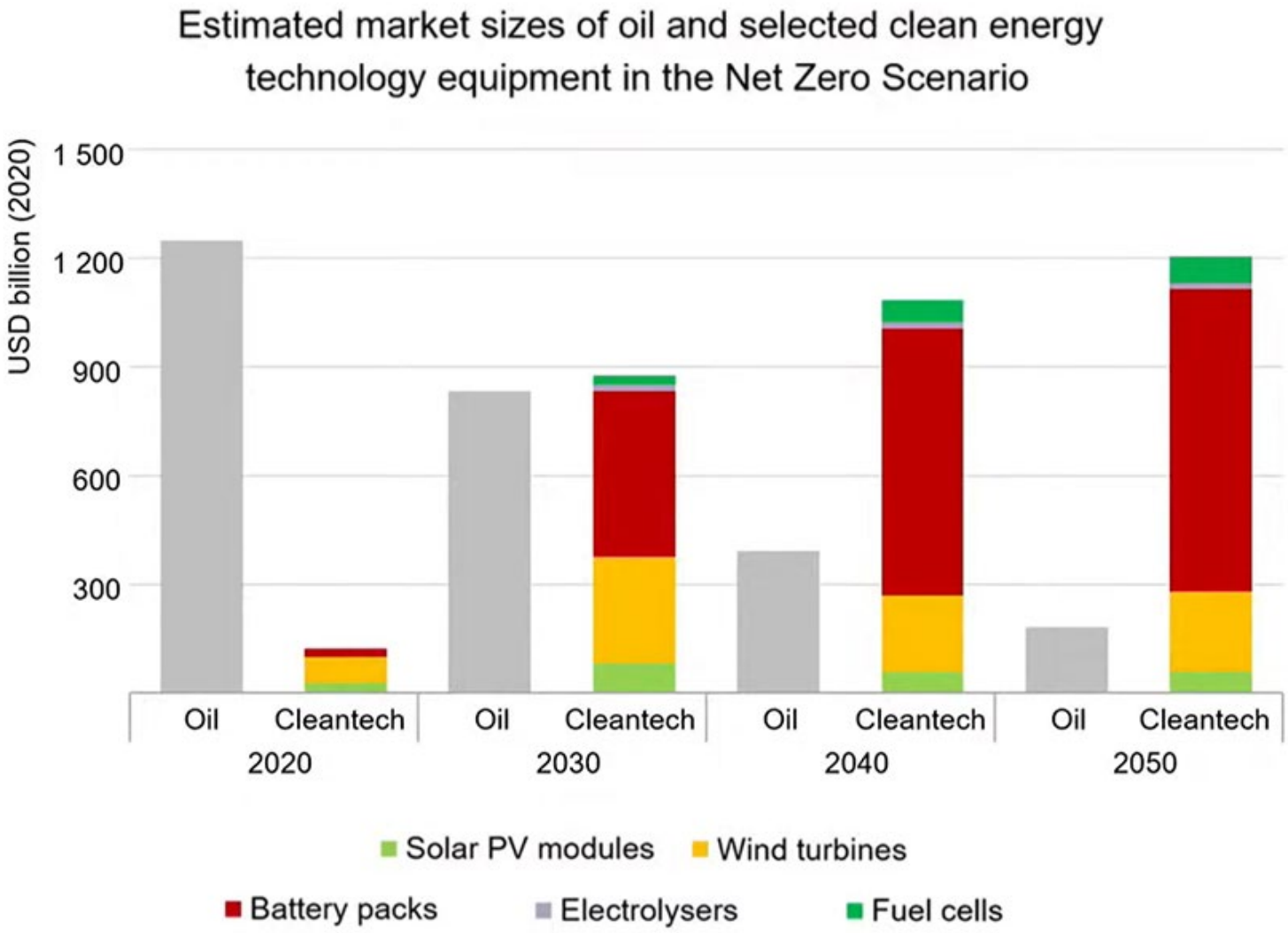
Grid Decarbonization Called 'Single Most Important Lever' for Policymakers

By K Kaufmann

With the U.N. Climate Change Conference set to convene in Glasgow on Oct. 30, the International Energy Agency's *World Energy Outlook 2021* report, released Wednesday, delivers a familiar but still urgent message: A virtuous cycle of policy action, technology innovation and low costs is powering a global energy transition that has strong momentum but is still not moving fast enough to cut global greenhouse gas emissions to net-zero by 2050 and limit climate change to 1.5 degrees Celsius.

"Every data point showing the speed of change in energy can be countered by another showing the stubbornness of the status quo," the report says. "For all the advances being made by renewables and electric mobility, 2021 is seeing a large rebound in coal and oil use," resulting in the second-largest annual increase in carbon dioxide emissions in history.

Intended as a guide for policymakers before the 26th Conference of Parties (COP26) in Glasgow, the report focuses on what it calls the "ambition gap" between countries' announced pledges under the 2015 Paris Agreement and the road to net zero.



The emerging clean energy economy could drive global markets valued at $27 trillion by 2050. | *IEA*

FERC/Federal News

"If we look at the CO_2 emission trajectory that the Glasgow pledges are bringing us to, and we compare it to where we would need to be if we were to follow a pathway consistent with 1.5 degrees … the Glasgow pledges, in 2030, would cover only 20% of this emission gap," said Laura Cozzi, IEA's chief energy modeler. "We are going into Glasgow not with the glass half-empty; it is actually 80% empty."

By 2050, the glass could still be 60% empty, with existing pledges producing only a 40% cut in emissions and a rise in global average temperatures of 2.1 C above preindustrial levels by 2100, the report says. The outlook based on existing policies, as opposed to pledges, is even more dire, with global average temperatures rising 2.5 C by 2100, with potentially devastating impacts to the energy sector, the report says.

One-quarter of global electric grids would face a high risk of destructive hurricanes and cyclones, while 10% of dispatchable generation and refineries would be prone to coastal flooding. "The frequency of extreme heat events would double by 2050 compared to today — and they would be 120% more intense, affecting the performance of grids and thermal plants while pushing up the demand for cooling," the report says.

With the report weighing in at 386 pages, response from U.S. energy groups was slow in coming. Gregory Wetstone, president and CEO of the American Council on Renewable Energy, called it "a wake-up call and a stark reminder of the challenge ahead."

"The IEA's World Energy Outlook confirms two things that we know to be true," Wetstone said in an email to *RTO Insider*. "First, in most markets around the world, the cheapest source of new electricity is renewable energy. Second, the public and private sector decarbonization commitments we have seen thus far, while ambitious, fall short of what scientists say is needed to avert a climate catastrophe."

$4 Trillion 'Surge' in Investment

Beyond COP26, such scenarios could hit home with U.S. policymakers following this summer's heat waves that melted power lines in the Northwest and the widespread power outages in Louisiana caused by Hurricane Ida. IEA's recommendations for bridging the ambition gap in the next decade also align closely with many of the climate and energy provisions in the bipartisan infrastructure package and budget reconciliation bill now increasingly mired in political battles in Congress:

- "Accelerating the decarbonization of the electricity mix is the single most important lever available to policymakers" and could close one-third of the emissions gap, the report says. In addition to doubling deployments of wind and solar over the amounts in the announced pledges, IEA calls for the expansion of nuclear, "where acceptable," along with "a huge buildout of energy infrastructure and all forms of system flexibility."
- Reducing energy demand with a "relentless" focus on energy efficiency is also part of IEA's net-zero vision, with government support to help consumers with the upfront costs of efficiency improvements. A drop in demand would be achieved by behavior change and more efficient technology and materials, the report says.
- Cutting methane emissions, particularly in oil and gas operations, could close another 15% of the emissions gap, the report says. "Methane abatement is not addressed quickly or effectively enough by simply reducing fossil fuel use; concerted efforts from governments and industry are vital."
- Ramping up innovation will also be critical to develop the emerging technologies needed for ongoing emissions cuts. Such technologies, in the development and demonstration stages, will be needed to tackle emissions from heavy industry — such as iron, steel and concrete — and long-distance transport. Advances in hydrogen and carbon capture, utilization and storage will also be needed.

The catalyst for progress on all these fronts is finance, the report says, calling for a $4 trillion "surge" in clean energy investment by 2030, with 70% of that amount channeled to developing economies. Government incentives to accelerate investments in flexibility, efficiency and demand-side response will also be needed.

IEA's net-zero world includes 240 million rooftop solar systems and 1.6 billion electric cars by 2050. "Such a system will need to operate very flexibly, enabled by adequate capacity, robust grids, battery storage and dispatchable low-emissions sources of electricity," ranging from hydropower and geothermal to hydrogen and small modular nuclear, the report says.

The call for accelerated investment is balanced by the report's findings on cost savings for consumers. Cozzi said that 40% of the emissions reductions needed by 2030 could be achieved with existing cost-effective technologies. Solar and wind deployments, backed up by improved market designs, could carry no cost for consumers, and energy-efficiency measures could provide cost savings.

"It is tough to understand why these emissions reductions are not on the table because there is not an economic rationale behind not doing them," she said.

Tim Gould, IEA's chief energy economist, also noted that an incremental energy transition, based on current policies, could raise consumer energy bills about 15% over the next decade versus a 10% decrease for the rapid energy transition needed to get to net zero.

An 'Unmistakable Signal'

With energy prices an increasing concern in the U.S. and worldwide, IEA Executive Director Fatih Birol addressed the issue and the "gross mischaracterization" that the situation is "the first crisis of the clean energy transition."

One of the main drivers of current high prices is the rebound in the global economy, mainly powered by fossil fuels, which Birol said is not sustainable. "Fossil fuels are growing very strongly; the prices are high, putting a break on economic growth," he said.

Other contributing factors include extreme weather events and planned and unplanned power outages, many from maintenance work that had been postponed because of the COVID-19 pandemic, he said.

"The clean energy transition is not the reason [for] what we are experiencing today," Birol said. "It may well be the solution."

Heading into Glasgow, Birol's wish list includes stronger emission-cutting commitments, more clean energy investment, especially in developing economies, and a strong message from world leaders "that we are united to build a clean energy future."

"Energy transitions depend on many groups — communities, companies, civil society, investors — but no one has the same capacity and influence as governments to shape our energy destiny," Gould said. "So, we look to government leaders in Glasgow for an unmistakable signal that they are committed to rapidly scaling up the clean and resilient technologies of the future." ■

FERC/Federal News

Reports: Clean Electricity Performance Program Killed by Manchin

Continued from page 1

The group said its modeling "underscores how important the CEPP is to achieving deep power sector decarbonization. Without it, emissions are likely to be 250 to 700 MMT higher per year in 2030, which could eliminate more than a third of the total emissions reductions under the infrastructure bills."

"This is absolutely the most important climate policy in the package," Leah Stokes, a climate policy expert advising Senate Democrats, told *The New York Times*, which *reported* Friday that CEPP was dead.

David G. Victor, co-director of the Deep Decarbonization Initiative at the University of California, San Diego, said both carrots (tax incentives) and sticks (penalties) are needed to clean up electric generation. "You need not just to deploy new stuff, but a way to retire old stuff," he *told* *The Wall Street Journal*. "The combination of the two is key."

The news had some proposing Hail Mary passes to save the program. "Time to make a deal with [U.S. Sens. Susan] Collins [R-Maine] and [Lisa] Murkowski [R-Alaska] to carve out the CEPP to get to 50 votes," *suggested author* Herb Simmens.

Manchin was unapologetic.

"Sen. Manchin has clearly expressed his concerns about using taxpayer dollars to pay private companies to do things they're already doing," Manchin's office said in a statement. "He continues to support efforts to combat climate change while protecting American energy independence and ensuring our energy reliability."

West Virginia Coal, Gas Ties

Many of those weighing in about CEPP's demise on Twitter took note of Manchin's *financial and political ties* to the coal and natural gas industries. West Virginia ranks second in coal and seventh in natural gas production among the 50 states. Enersystems, a coal brokerage Manchin founded in 1988 and now run by his son, represents 30% of his net worth. He *reported* $491,949 in dividend income from the company in 2020, 71% of his total investment income.

But others said Manchin had valid policy concerns.

"The media narrative that [Manchin] is single handedly blocking the president's agenda is absurd and unfair," *tweeted* former FERC Chair Neil Chatterjee. "There are FIFTY other U.S. senators who strongly oppose this legislation."

"CEPP was a lucrative giveaway for utilities to consolidate their monopoly power and generouslyyyyy incentivize already cost-effective generation," *tweeted* Maggie Clark, director of government affairs for *Pine Gate Renewables*, a North Carolina-based company that does project development and strategic financing of utility-scale solar and storage projects.

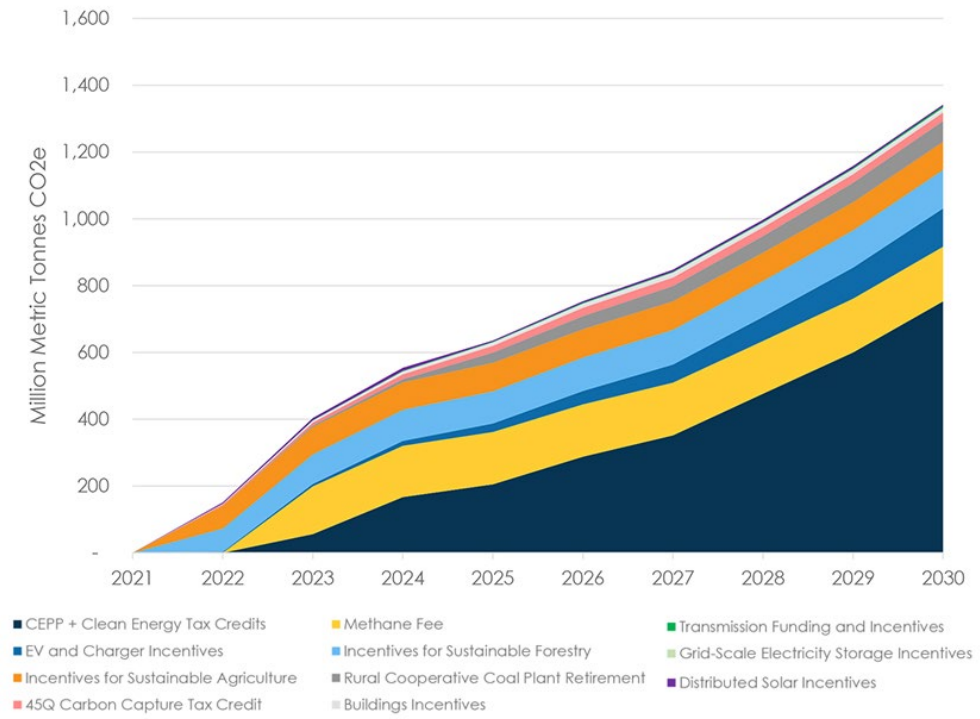
"A clean energy standard as traditionally designed is one thing. Crafting that policy to fit under reconciliation parameters led to progressives rallying around a government giveaway as the magic solution to climate change. Come on," she said. "Clean energy wins on price today. The barrier to widespread adoption is inadequate infrastructure. Take every dollar away from CEPP and put it towards grid upgrades and then we're getting somewhere."

Others noted that in addition to the clean energy tax credits, the Democratic bill also includes $32 billion in tax credits to encourage the purchase of electric vehicles, $13.5 billion for electric car charging stations, $9 billion to update the electric grid and $17.5 billion to reduce carbon dioxide emissions from federal buildings and vehicles.

"Clean energy tax credits are nothing to sneeze at," *tweeted* Robin Dutta, who works on market development and policy in the federal affairs staff of rooftop solar company *SunPower*. "And might be more effective than whatever CEPP could do."

"Despite the attention paid to it, CEPP is actually less potent as a greenhouse-gas slayer than those boring tax credits, which are less controversial because they do not overtly penalize coal or gas," *The Economist* reported.

"Two energy veterans, one at a top renewables lobbying outfit and the other at a fossil-heavy utility, agree that the tax credits would sharply boost investment in low-carbon technologies," it said. "That is because they improve the current setup by replacing stop-go uncertainty with a predictable long-term tax regime and make tax breaks 'refundable' rather than needing to be offset against tax liabilities, meaning even utilities that do not have such tax liabilities can enjoy them as freely as cash in the bank."



Emissions reductions expected to result from provisions in the bipartisan infrastructure bill and the broader legislation Democrats hope to pass on party-line votes, based on Energy Innovation's "moderate" scenario. The loss of the Clean Electricity Performance Program (CEPP) would undermine President Biden's goal of reducing U.S. greenhouse gas emissions to 50% below 2005 levels by 2030. | *Energy Innovation: Policy and Technology*

FERC/Federal News

In addition, more than half the states are implementing their own climate policies. Twenty-six states, representing 61% of the U.S. economy, have joined the *U.S. Climate Alliance*, which was created after former President Donald Trump announced the U.S. would withdraw from the Paris Agreement.

CEPP Vital Signs Waning

The *Times* reported that Manchin, chairman of the Senate Energy and Natural Resources Committee, was considering a clean electricity program that would reward utilities for switching from coal to natural gas. But last week, it said, Manchin told the White House he was completely opposed to a clean energy program.

CNN *reported* that it will "likely be dropped," and Bloomberg *reported* it had confirmed the *Times*' report.

"Per a person familiar, while a final decision hasn't been made, without Manchin's support there isn't a path forward for the climate program," Bloomberg's Ari Natter *tweeted*.

The *Journal* *reported* the program was "is in danger of falling out" of the Democrats' bill.

The Washington Post *reported*: "White House officials have not decided to completely jettison the CEPP but are instead looking at how to make changes that would ensure Manchin's support for the broader economic package."

"It's not dead yet, per people familiar, but it's struggling to stay in the talks given Manchin's opposition," *tweeted* POLITICO's Zack Colman, who *reported* Wednesday that Democrats and the White House were discussing ways to amend the CEPP to allow natural gas and coal power plants with carbon capture to participate. "The changes I reported Wednesday are part of what's being explored to bring Manchin to the table, but this latest reporting suggests the needle hasn't moved."

Manchin has recently expressed doubts about the viability of carbon capture. "It's so darn expensive that it makes it almost impossible," he *said* last month.

Legislative Scramble as COP26 Approaches

Progressive Caucus Chair Pramila Jayapal told MSNBC on Saturday that "there's no decisions that have been made. The negotiations are continuing.

"We understand that we have to get 50 senators on board and that Sen. Manchin obviously has a very big role to play on this," she said. "We're open to that negotiation as long as we have strong climate protections that bring down carbon emissions. That's the discussion that's under way right now."

The *Post* *reported* Saturday that White House officials are "still looking at whether they can preserve the clean energy program by providing a way for coal and natural gas plants to keep operating for longer." It said another idea being considered was a voluntary emissions trading system among aluminum, steel, concrete and chemicals manufacturers that would provide federal funding to help them reduce emissions.

Earlier last week, Special Presidential Envoy for Climate John Kerry suggested Biden's position at the *COP26* talks beginning Oct. 31 would be weakened by the lack of a climate deal with Congress. Failure to pass such legislation "would be like President Trump pulling out of the Paris Agreement again," he *told* the Associated Press.

On Friday night, Biden called Kerry's comments "a little hyperbole."

"It'd be good to have agreement on the climate piece, but we're going to get the climate piece," he said. ■

FERC/Federal News

FERC Tx Inquiry: Consensus on Need for Change, Discord Over Solutions

Wide Support for GETs; Incumbents Seek to Restore ROFR

Continued from page 1

prescriptive rules, particularly around the inputs into planning studies and analyses, so that planning processes will be able to accommodate evolving technology, state laws, regulatory structures, and policy preferences," said the National Association of Regulatory Utility Commissioners (NARUC).

States' Roles

Many comments dealt with what role the states — whose renewable portfolio standards and climate policies are helping drive the historic transition in the generation mix — should play in planning the transmission needed to connect renewables to load centers.

NARUC said it "shares the commission's perspective on the need to reform existing planning processes."

But it said "the commission should not lose sight of the need to ensure that all potential transmission planning reforms explicitly recognize the essential role states, and state laws, play in this process."

The National Conference of State Legislatures (NCSL) called for a "coordinated effort between FERC and states in the development and implementation of any regulatory change, including devising improved mechanisms to bring state legislatures into the energy decision-making process as full participants on an ongoing basis."

NCSL said FERC should support the development of state-created regional mechanisms, such as interstate compacts and regional reliability boards, "to address transmission reliability, problems related to the interconnectedness of the energy grid, environmental impact of generating electricity, and other regional energy issues."

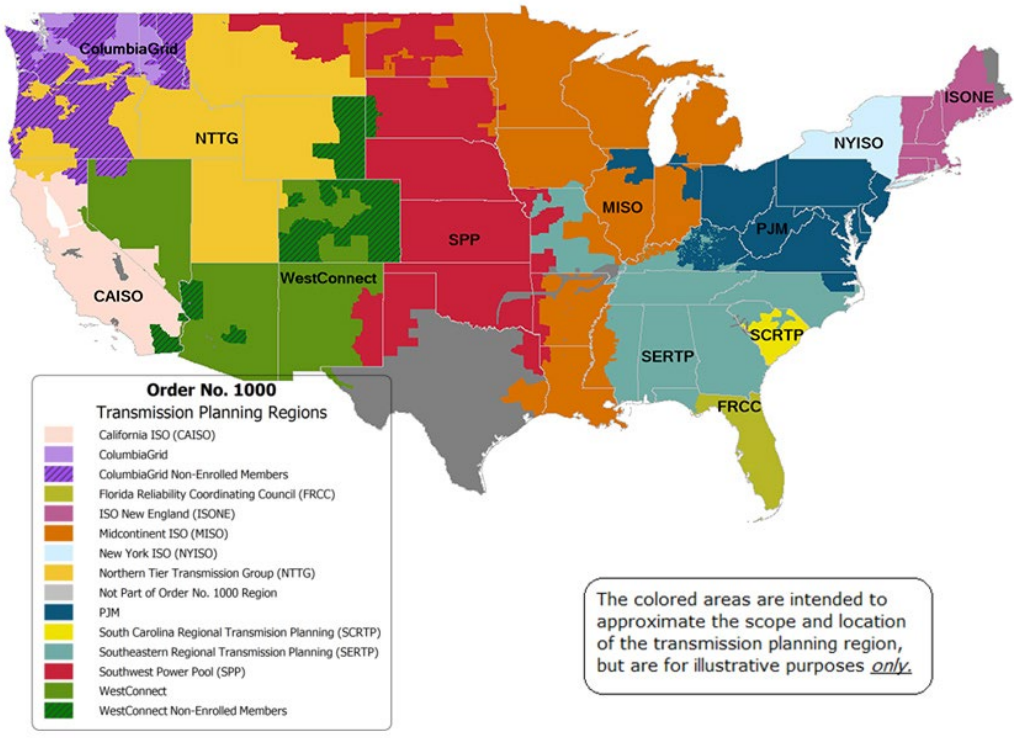
But the National Rural Electric Cooperative Association (NRECA) said state commissions "should retain their role as stakeholders in Order No. 1000 regional transmission planning and cost allocation processes and not as overseers. Any expansion of that role, such as the SPP Regional State Committee authority noted in the ANOPR, should be the result of regional decision-making and not commission mandate."

Participant Funding

One question FERC asked commenters to answer was whether it should eliminate rules that allow RTOs/ISOs to use participant funding for interconnection-related network upgrades or whether the costs should be "allocated more broadly among those that benefit" from increased transmission capacity.

EDP Renewables North America said it has "effectively abandoned" development plans in much of MISO West and SPP because of the high costs assigned to its proposed projects. It said it was forced to cancel a 100-MW wind project in Minnesota that was in the final stages of a power purchase agreement negotiation after learning it would be assessed more than $70 million in network upgrades.

Filing jointly, the American Clean Power Association and the U.S. Energy Storage Association, said the commission should eliminate participant funding for network upgrades and shift transmission planning and cost allocation to "a holistic and proactive process that simultaneously addresses key drivers, including — but not limited to — economic, reliability,



Order 1000 transmission planning regions | *FERC*

FERC/Federal News

public policy, and future generation needs."

The groups proposed that generators, or clusters of generators, would have the sole responsibility for the costs of interconnection-related network upgrades up to and including the interconnection substation, with upgrades electrically "downstream" from the interconnection substation being the responsibility of the transmission provider.

But NRECA said existing policy, including allowing participant funding, "provides the appropriate price signal in nearly all cases."

NRECA agreed that improvements are needed in generation interconnection processes in some regions. "NRECA members support generation-interconnection reforms that address these issues directly rather than simply shift most of the costs and risks to the customers of load-serving entities and thereby dampening if not eliminating appropriate economic incentives and price signals to interconnecting generators."

NARUC also urged more incremental changes, saying FERC should "retain the core tenet of participant funding, while exploring the as yet untapped potential economies of scale that could result from increased coordination among participants," including generators sharing costs in "clusters."

"Contrary to the apparent presumption in the ANOPR, some state commissions' experience is that the network upgrades needed to allow generation interconnection do not provide benefits to transmission customers as a whole," NARUC said.

The Transmission Access Policy Study Group (TAPS), which represents transmission-dependent utilities, recommended allocating costs of proactively planned upgrades to beneficiaries. "If costs remain to be allocated, consideration of load zones expected to rely on the generation that the proactively planned transmission is designed to support could be appropriate. Consistent with fundamental cost allocation principles and given the tensions associated with broad cost allocation, it should be used sparingly."

TAPS said eliminating RTOs' ability to directly assign interconnection-related network upgrades costs would remove interconnection customers' incentive to site wisely, "an inducement that will be essential as we move toward reliance on proactively planned facilities."

Dominion said the commission should continue to ensure that those who receive the benefits of the investments are assigned the costs. "This means not generically socializing transmission costs, refraining from using transmission as a subsidy to speculative generation projects, and avoiding stranded costs for customers."

	Proactive Generation & Load	Multi-Value	Scenario-Based	Portfolio-Based[30]	Joint Interregional Planning
ISO-NE[31]	✗	✗	✗	✓	✗
NYISO[32,33]	✗	✗	✗	✗	✗
– PPTPP only	✓	✓	✓	✓	✗
PJM[34,35]	✗	✗	✗	✗	✗
Florida	✗	✗	✗	✗	✗
Southeastern Regional	✗	✗	✗	✗	✗
South Carolina Regional	✗	✗	✗	✗	✗
MISO (excl. MVP, RIIA)[36]	✗	✗	✗	✗	✗
SPP (ITP)[37,38]	✗	✓	✗	✓	✗
CAISO[39,40]	✓	✗	✓	✗	✓
– TEAM only	✓	✓	✓	✓	✓
WestConnect	✗	✗	✗	✗	✗
NorthernGrid[41]	✗	✗	✗	✗	✗

"The failure to conduct multi-value, scenario-based transmission planning on a regional and interregional portfolio basis is endemic to the grid," the Natural Resources Defense Council, the Sierra Club and other public interest organizations told FERC in their comments on the transmission ANOPR. | *The Brattle Group and Grid Strategies*

"Wind and solar are important components to a clean energy future, but … new technologies, such as green hydrogen, small modular nuclear reactors, and new battery technology, could transform power generation in the future as well," it continued. "Such technologies for the benefit of Dominion Energy's customers should not be discounted by a transmission policy that favors certain types of resources over others."

The Electric Power Supply Association (EPSA) also opposed broad socialization of transmission upgrade costs, saying the commission should instead "focus on reducing transaction costs, speeding up lagging processes, and adopt market-based approaches, like an open season" for transmission access.

"System planners could hold an open season competitive procurement to solicit bids from suppliers, developers, customers, or even states which could support the build of long-line transmission facilities or network upgrades," EPSA said. "Rather than using a model like CREZ in Texas which socializes the costs to build transmission first to incent an influx of hopeful supply, an open season brings the interconnection customers to the table to demonstrate that transmission development would be prudently located and supported by sufficient commercial interest."

EPSA said such a plan would not "rely on forecasting — which is rarely sufficiently accurate, if accurate at all — but could allow states or local entities to sign on to a project to signal a future need to fulfill state policies or goals."

"While cost allocation may require consideration for revisions, a full reassessment or reversal of participant funding and cost causation principles in order to socialize costs may overstate identified benefits and warp the signals needed to support baseline transmission upgrades, even public policy projects," EPSA said.

Planning Methodology

FERC also asked what metrics and time horizons transmission planners should use and whether they should consider potential generation not in their interconnection queues.

Several commenters said the transmission planners should use longer time horizons.

American Electric Power said need analyses should consider a 20-year horizon. "The commission's focus is best directed at working with the North American Electric Reliability Corporation (NERC) and the RTOs to develop a set of planning standards, including benefits metrics and study scenarios, drawing on best practices found in existing planning processes, to create a baseline methodology for transmission planning that will apply to all RTOs and non-RTO regions," AEP said.

NARUC said it supported "a long-term planning process to allow stakeholders to evaluate transmission system needs and conditions as the system integrates resources that states want to develop in the future. In some cases, states' energy laws and policies look well

FERC/Federal News

beyond the ten-to-fifteen-year timeframe typical for transmission planning studies," it noted.

But NRECA said a planning horizon of 10 years is "generally … appropriate" and consistent with NERC's transmission planning (TPL) reliability standards and state integrated resource plans (IRPs).

Numerous commenters, including the Edison Electric Institute (EEI), which represents investor-owned utilities, agreed with the commission that one way to account for future uncertainty is with increased use of scenario planning that considers several plausible futures.

The Solar Energy Industries Association (SEIA) said planners should include carbon reduction and integrating renewable generation among the "benefits" considered in evaluating potential projects. "The commission, therefore, should require transmission providers, and ISO/RTOs in particular, to monetize the broader societal effects in transmission planning and cost allocation," SEIA said.

It said FERC should require transmission providers to establish a fee, separate from any interconnection deposit, based on project size, to be charged for submitting an interconnection request. "For projects that require network upgrades, the fee would be applied towards the cost of the network upgrades. The remaining cost of the network upgrade would be allocated to the load zone served by the project."

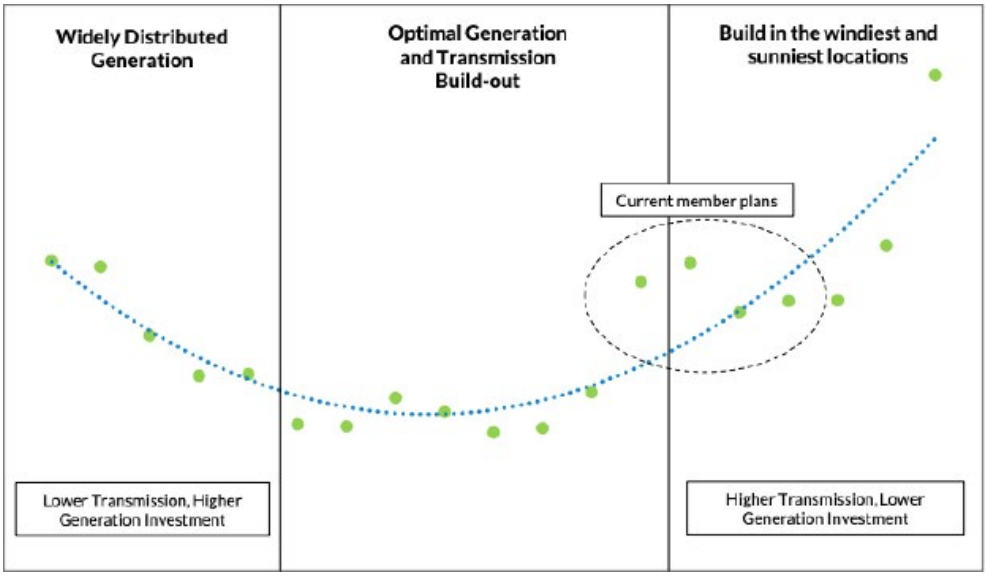
But the Southeastern Regional Transmission Planning Process (SERTP), which includes Duke Energy, the Tennessee Valley Authority and Southern Co., warned FERC against "unlawfully intruding into resource/IRP planning reserved to the states or inappropriately seeking to force 'substantive outcomes' rather than merely regulating the transmission planning process."

It said FERC should "retain the prevailing quantitative, objective assessment of transmission benefits used for regional transmission cost allocation processes. The suggested consideration in the ANOPR of qualitative and 'hard to quantify' benefits would unnecessarily complicate cost allocation."

NRECA opposed building transmission facilities to accommodate anticipated future generation not yet in the interconnection queue.

"The ANOPR cites no data to support a finding that 'too much' network transmission infrastructure (e.g., in dollars or transfer capacity or number of projects) is built through the existing generation interconnection process — much less any data on the lost efficiency in transmission investment that this might entail or the efficiency gains and losses to be expected by potential replacement processes."

It said the commission lacks "the authority or expertise to require regional transmission planning processes to quantify the benefits of clean-air attributes of newly interconnected generation and identify the beneficiaries for purposes of regional transmission cost allocation."



MISO planners seek the least cost sweet spot, where transmission additions are lower and there is both a mix of local and remote generation. | *MISO*

ROFR and Transmission Competition

EEI and Dominion were among those urging the commission to reinstate the federal right of first refusal for projects selected for regional cost allocation, which was eliminated in Order 1000, although the commission allowed states to enact their own ROFRs.

"This policy has resulted in a near standstill in transmission development for regional projects and a substantial increase in process-related costs," EEI said.

"Allowing transmission owners to work with the state and outside of the constraints imposed by the current inflexible and inefficient RTO process can expedite transmission projects," Dominion said.

EPSA disagreed, insisting "any reforms to transmission policies leverage the commission's commitment to competition to ensure that cost-effective transmission investments are signaled and supported by planning, cost allocation, and/or interconnection processes, including the use of competitive procurement processes."

TAPS also called for continuation of the current rules on competitive transmission development, which it said "has been effective in reducing costs where it has been used."

Independent Transmission Monitors

There was no consensus on whether the commission should establish independent transmission monitors to evaluate plans to ensure that the projects are the most efficient or cost-effective.

Pine Gate Renewables, a utility-scale solar developer based in Asheville, N.C., said a monitor is essential, contending that transmission planning processes in non-RTO/ISO regions are "opaque with virtually no opportunity for meaningful input from independent power producers or other stakeholders."

It said SERTP "provides very little information to stakeholders and essentially no opportunity for substantive engagement," noting that it is comprised exclusively of load-serving entities. "Order Nos. 890 and 1000 have had no meaningful impact on the Southeast," the group said.

NRECA, EEI and SERTP opposed the concept.

"There is sufficient oversight and transparency in the transmission planning and cost allocation process and another layer of review through an independent transmission monitor is not needed," said EEI. "… There is no evidence that the existing processes, whether

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in or outside of a RTO/ISO region, are failing to implement tariffs appropriately or that the processes produce unjust and unreasonable outcomes."

SERTP said a monitor "would unlawfully second-guess state-regulated IRP and bundled retail transmission service decisions, create friction points in the system expansion process, and cause resulting delays, litigation, and increased costs."

It conceded SERTP could expand its transmission planning "to better inform decision makers and stakeholders by accommodating additional, proactive scenario-based planning processes that would not directly dictate construction."

NARUC said such monitors "may be beneficial" but that the "concept and role that the commission envisions for transmission monitors is, at this time, unclear."

It also questioned whether the commission has the authority to order independent monitors in areas outside of ISO/RTOs.

TAPS said a monitor "could play an important role in non-RTO regions and for local planning in RTOs."

SEIA said a monitor that evaluates plans to ensure that the projects are the most efficient or cost-effective "could ensure that projects benefit the whole region, and not just a single utility."

RTOs Weigh In

RTOs also called for the commission to allow regional flexibility in any new rules.

CAISO said it agrees that planning should include anticipated future generation but said FERC should "grant regions sufficient flexibility to implement this approach based on their specific circumstances."

PJM said its current rules are balanced "in that interconnecting generators pay their 'but for' costs to interconnect to the existing transmission system, while load thereafter bears the costs of ensuring continued deliverability of those generators once interconnected."

Any change to the policy "should account for a reasonable allocation of risk and reward to ensure that the change in policy choice does not result in an unreasonable shift of costs or risks to load," it said.

The RTO also said resilience must be part of transmission planning and that FERC should create a "common working definition" of the concept and "resilience-based industry planning drivers."

PJM said an independent monitor is not needed in RTOs and ISOs and "would be far more appropriate … in areas where there is no structural independence as between the transmission planner and its generation affiliates."

"The oversight function over costs of transmission and the prudence of those investments not reviewed through the [Regional Transmission Expansion Plan] are best addressed by improving customers' ability to make their voices heard through the commission's regulatory process," it said.

ISO-NE said FERC should "explore process enhancements to address any identified concerns before establishing another independent entity to monitor transmission planning, which could inadvertently weaken, and introduce delays and risks into a well-functioning, open and transparent process, at the expense of getting transmission built in time to meet identified needs."

NYISO said "incremental, yet significant, reforms can meaningfully address many of the issues raised in the ANOPR.

"Adoption of targeted reforms can have a more immediate impact than a complete overhaul of the existing processes, which would take considerable time to develop, implement and, ultimately, to result in new transmission," it said. "Moreover, attempting to address all transmission needs and issues simultaneously through a single, unified process may be overly complex, slow and inflexible."

SPP said it already uses several of the commission's proposed initiatives, noting that its Integrated Transmission Planning uses several future scenarios to evaluate a range of potential outcomes "under a variety of projected load, generation mix, and grid usage conditions."

MISO said it has been conducting stakeholder processes "addressing nearly all of the topics raised in the ANOPR, and more, to address the evolving system."

Grid-enhancing Technologies

One solution likely to get a boost from the rulemaking is grid-enhancing technologies (GETs).

"Going forward, GETs may play an important role in increasing efficient use of the system and providing a short-term solution until needed transmission is built," EEI said. "However, additional experience is needed to determine how best to model and operate these technologies." ■

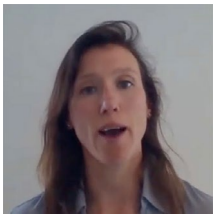
FERC/Federal News

Stakeholders Ask FERC to Support E&AS Market Changes

By Michael Kuser and Michael Yoder

Participants at the final session of FERC's technical conference on energy and ancillary services (E&AS) Oct. 12 agreed overall that market participation rules need to be revised to ease the entry of new and emerging resource types into the wholesale electricity markets (*AD21-10*).

"The panelists informed us of a lot about this incredibly complicated, challenging problem" of incenting new resources while maintaining grid reliability, concluded Emma Nicholson, an economist at *FERC* who helped moderate the day's sessions. "We at staff are heartened by how many bright, smart people are analyzing this problem from different points of view so we can crowdsource some really good solutions here."



Emma Nicholson, FERC | *FERC*

The commission held the first session of the conference last month and now will likely issue a call for comments, she said. (See *Flexible Ramping Grows as Ancillary Service*.)

Revising RTO/ISO Market Models

Investors in new technologies such as storage resources, hybrid and co-located resources, aggregated distributed energy resources, and standalone variable energy resources want to be sure that the new assets will be able to offer their full operational capability in the market.

On the other hand, RTOs and ISOs wrestle with the difficulty of adapting their market software and rules to accommodate such resources — an uncertainty factor — while fulfilling what many consider to be their primary responsibility of maintaining reliability.

There are two sides to the challenge of incorporating uncertainty into market software because providing electricity "is really preserving ramp capability from one interval to the next so that [it] can be available and deliverable

The Connolly Energy Storage System of Southern California Edison is located on the Pronghorn Circuit near 15 solar farms. | *Southern California Edison*

FERC/Federal News

George Angelidis, CAISO | *FERC*

in the next market run where uncertainty potentially materializes," said George Angelidis, principal for power systems and market technology at *CAISO*.

The second aspect is coming up with a reasonable methodology for calculating the uncertainty requirement without tremendous effort because you have to do it constantly as the market runs to update the requirements, Angelidis said.

Jinye Zhao, ISO-NE | *FERC*

For Jinye Zhao, principal analyst for advanced technology solutions at *ISO-NE*, the first question is how to reduce the magnitude of uncertainties; in other words, how to reduce the problem size.

"Given that there are always uncertainties in the system, what solution strategies can we use to manage uncertainties?" Zhao said.

Erik Ela, EPRI | *FERC*

Erik Ela, program manager for the Electric Power Research Institute, gave his perspective on *ERCOT*, which is not under FERC's jurisdiction. Day-ahead forecasts for load, wind and solar used by the Texas grid operator are currently only used in the reliability unit commitment (RUC) process. This is run after the day-ahead market, with a primary focus of committing sufficient resources that require a day-ahead notification time while minimizing commitment costs, so resources committed in the day-ahead market are not de-committed, he said.

"If for example the renewable forecast is higher than the renewable bids, it is often the case that the incremental energy costs are ignored or largely discounted so that only the commitment costs are of concern," Ela said.

Bethany Frew, NREL | *FERC*

The value of improved forecasts depends on both the amount of renewables and thermal units in the system, said Bethany Frew, senior engineer at the National Renewable Energy Laboratory.

"We've seen consistently across different studies almost a transition zone where as you start to increase the amount of renewables on your system, specifically variable renewable resources like wind and solar, and you start to reduce the amount of thermal units in the system, there's this transition beyond which commitment-related impacts can be diminished," Frew said.

Specifically, start-up costs are one of the areas where NREL researchers see a lot of value in improved forecasts, but as thermal units are removed or they get retired in future scenarios, the value of those forecasts declines, she said.

"There's really this interesting kind of interplay between what's happening in the rest of the system and the forecast quality," Frew said.

Arne Olson, E3 | *FERC*

Arne Olson, senior partner at Energy and Environmental Economics, had multiple recommendations. First, market operators must develop scientific methods for determining the quantity of ancillary services needed based on continually changing grid conditions. The upward and downward reserve product should also be specified and procured separately. Wind and solar projects have asymmetric cost functions, which are only partly ameliorated when the services dispatch upward in real time, Olson said.

"Finally, and most ambitiously, we should look to market software to optimize the use of energy storage," Olson said. "This is the most flexible resource available in the market, but its costs are entirely defined by market opportunities to buy low and sell high. As substantial quantities of storage are added, it will be increasingly important for market software to optimize its use."

Ultimately, the ideal state at *MISO* would be to design and modify markets to remove barriers and create incentives for emergency-only resources such as load-modifying resources, said Laura Rauch, director of settlements for the RTO. "In particular, that long-lead emergency resources be committed and dispatched to market operations is a paradigm that enhances market efficiency for greater transparency."

SPP deploys an uncertainty response team

Yasser Bahbaz, SPP | *FERC*

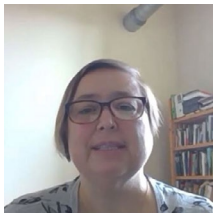
that talks on a daily basis and looks at the amount of uncertainty that the grid operator projects it will have to deal with, "and then the bulk responsibility of this team is to recommend some amount of capacity of generation that needs to be online," said Yasser Bahbaz, manager of reliability coordination for the RTO. "And these are all recommendations that are made out-of-market because we don't have a product that specifically deals with density and uncertainty."

NYISO has been doing a good job for 20 years reducing out-of-market commitments, said Liam Baker, vice president of regulatory affairs for Eastern Generation. "Because of all the market power rules in New York City, I have to offer most of my products at cost or at zero. So as an investor ... I want to see accurate price formation," Baker said.

System Flexibility

One panel discussed whether energy and ancillary service market participation rules need to be changed to ensure that resources have incentives to offer operational flexibility to the RTO and ISO markets.

The panelists stressed the importance of system flexibility in the markets.



Nicole Bouchez, NYISO | *FERC*

Nicole Bouchez, principal economist in NYISO's market design department, said New York is focused on the wholesale energy products that are needed for reliability "in the face of an evolving resource mix." At the same time, Bouchez said, NYISO is also attempting to ensure the "broadest set of resources possible" can participate in the markets.

Bouchez said NYISO's structure of market rules are designed to increase the financial returns for resources that perform flexibly and reliably in the real-time markets and reduce compensation for inflexible resources. Co-optimization in the energy and ancillary service markets and not in the day-ahead and real-time markets, Bouchez said, causes the prices to "reflect the cost of systems" that provide ancillary services and provide compensation when a unit "would otherwise

FERC/Federal News

be providing energy."

"This opportunity to sell different products also has the potential to encourage resources to make investments or modify operating practices to participate in those markets," Bouchez said. "These investments can, however, be costly, which is why the focus on reliability and the products needed to maintain reliability is so important."

Joseph Daniel, UCS | *FERC*

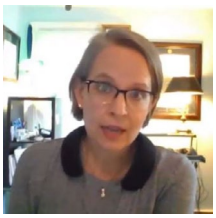
Joseph Daniel, manager of electricity markets and the climate and energy program for the Union of Concerned Scientists, stressed why he believes flexibility to be important. Daniel said flexibility boils down to "reliability and affordability" with a more flexible grid lowering costs for consumers and bringing reliability through new technologies.

Daniel said sometimes he finds it difficult to "disaggregate" some of the flexibility issues with what he calls "uneconomic behavior in the markets." He said when he looks at the current rules governing the energy and ancillary services markets, he's concluded that "most of today's rules were written for yesterday's resources" and all someone has to do to see the future is look at the generation queues of RTOs and ISOs to see the changing resource mix.

Daniel said he's encouraged by FERC orders 841 and 2222 that demonstrate the commission is "working to find ways to accommodate that inevitable wave of lower cost, more flexible resources." But he said rules governing the commitment and scheduling of resources "tend to bias towards inflexible, long lead-time resources" and work against newer, flexible technologies.

"FERC should pursue market fixes to promote competitive resources and to offer in the full range of possibility," Daniel said. "As we make these steps towards creating market rules that will promote flexibility, we should recognize the limitations to that and try to find ways to make sure the market rules objectives actually achieve what we're solving for."

Michael McLaughlin, director of FERC's Division of Economic and Technical Analysis, asked, "Do any existing RTO/ISO energy and ancillary service market rules, requirements or procedures actually encourage resources to offer into the market inflexibly, and if so, what changes should be made?"



Catherine Tyler, Monitoring Analytics | *FERC*

Catherine Tyler, deputy market monitor for Monitoring Analytics, the Independent Market Monitor for *PJM*, said the way McLaughlin's question was framed is "not quite the right" one. Tyler said stakeholders shouldn't be worried whether resources offer flexibly but instead focus on the "need" for resources to perform flexibly.

Tyler said PJM rules require offering flexible parameters, including must-offer requirements in energy and reserve markets. She said there's "plenty of flexibility on paper," but there's a "general lack of accountability" when it comes to performing flexibly in the markets. For example, there are no repercussions in the outage or uplift rules for failing to meet must-offer requirements. A potential solution would be penalties based on capacity market prices, which are paid for meeting certain performance standards.

"The market needs to account for the performance of the resources," Tyler said. "Customers pay a premium for capacity that is meant to meet performance standards."

Emerging Resources

Panelists discussed some of the issues keeping new technologies from entering and flourishing in markets.

Jason Burwen, ESA | *FERC*

Jason Burwen, interim CEO of the Energy Storage Association, said one of the early lessons with the development of energy storage technology is that flexible storage is running into market processes that are not providing "commensurate operator control" and weren't written with that technological capability in mind. It's important for the commission to take a "wide view" on the paths forward on potential market rules to "continue to ensure policy keeps up with technology" and not allow technology limitations "constrain our future."

"The grid of the future will need more flexible, fast-starting resources, and we need to make sure that we reflect the cost of a lack of performance meeting that," Burwen said.

Aaron Siskind, an economist with FERC, asked whether existing RTO/ISO energy and ancillary services market rules, practices or procedures prevent or otherwise obstruct relatively new and emerging resource types, such as variable, hybrid and storage, from fully participating in RTO/ISO markets and offering the operational flexibility they are capable of providing from a technical standpoint.

Michael DeSocio, director of market design for NYISO, said the current market structure is "built to reward those that can move quickly, follow dispatch instructions closely and be responsive to emerging grid needs." To be prepared for the continuing energy transition and the grid of the future, stakeholders need to "think more broadly" on solutions for market structures to ensure resources continue to respond to grid needs and operator instructions. He said there is also "a need to provide additional information more frequently" by resources submitting more data to the RTOs and ISOs for more efficient operations.

"This promotes improved efficiency and better price formation," DeSocio said. "All of these pieces and parts are important."

Walter Graf, PJM | *FERC*

Walter Graf, senior director of economics for PJM, said the objective should not be to maximize operational flexibility but to "incentivize the efficient level of operational flexibility across all resources." PJM is behind other areas in the country in respect to the penetration of emerging and intermittent technologies, giving it the "benefit" of having more time to address market design deficiencies "before they become problems."

Graf said PJM "continues to believe in the ability of the competitive market to signal value through prices" and the ability of market participants to best make decisions. Graf said incentivizing flexibility and ensuring that sufficient flexibility is available when needed is the role of the energy and ancillary service markets.

"PJM believes that operational needs should guide the design of needed services and should not be compromised to accommodate resources that are unable to comply," Graf said. "That said, there are cases where value can be unlocked or enabled without compromising operational requirements." ■

FERC/Federal News

DOE: Atlantic Coast Needs Integrated Tx Planning for OSW

Report Says Traditional Planning Misses Opportunities for Shared Transmission Projects

By K Kaufmann

While Interior Secretary Deb Haaland was in Boston on Wednesday announcing the Biden administration's plans for deploying 30 GW of offshore wind, the Department of Energy released a new report on the gaps that will need filling to build enough transmission to get electricity from those turbines to the millions of homes they might power.

The *report* reviews more than 20 transmission studies for Atlantic Coast OSW projects to date and finds most were done on a project-by-project basis, "which may not necessarily be optimal for expanded development." With a current pipeline of more than 35 GW of projects extending from Maine to Virginia, comprehensive, proactive transmission planning that incorporates "robust future scenarios across the broader interconnected system" will be needed, the report says.

Such an approach is essential, the report says, because of a frequent mismatch between the potential high output of offshore wind generation and daily variations in power demand, which can result in curtailment and transmission congestion.

For example, the report notes that *ISO-NE* will need minimal upgrades to interconnect the 5.8 GW total of offshore wind now being developed in Connecticut, Maine, Massachusetts and Rhode Island. Additional offshore projects could result in higher costs and curtailments, the report says.

NYISO, on the other hand, is facing cable routing limitations, substation space constraints and permitting challenges as it looks to expand and upgrade transmission on Long Island and in New York City to integrate the state's planned 9 GW of OSW.

As an alternative to states going it alone, the report says transmission planning should look at co-optimizing systems with "generation and storage technologies to holistically compare completely integrated alternatives that capture generation and transmission trade-offs to adequately meet customer demand and federal and state policy objectives."

Reaching such objectives will mean addressing research gaps in four key areas, the report says.

- Studies by individual states, RTOs and ISOs — encompassing a range of study years and OSW deployment scenarios — generally assume the states involved each have a specific claim on offshore wind resources. But state and national goals may not be aligned, creating "a gap in understanding the Atlantic Coast and Eastern Interconnection implications of how offshore wind will be utilized by different states," the report says.
- Similarly, interconnection studies by RTOs and ISOs tend to be "deployment-specific," focusing on single projects. While long-term planning efforts have begun, the report says traditional transmission planning misses the potential for collaborative solutions, such as shared transmission or shared rights-of-way that could minimize costs and impacts.
- Technical and economic analyses of offshore wind have been widely conducted along the Atlantic Coast, but few states have yet to look at the details of routing and interconnecting transmission cables. Further, current analyses don't account for technologies that need further development, such as high-voltage DC circuit breakers, which will be essential for developing offshore HVDC transmission, the report says. Without such in-depth analysis, technical solutions could be proposed that are either infeasible or overly costly.
- With some technologies still in development, standards and practices for integrated offshore transmission networks are a critical gap in current analyses, the report says. As one example, many studies make future estimates of project reliability and resilience based on a year or less of weather data, the report says. This approach can leave out high-impact events like hurricanes and other "natural patterns of variability and uncertainty that occur over longer periods and for which the system should be designed."

| Dominion Energy

The FERC Connection

Stepping up research — and accelerating offshore wind development — will require collaborative efforts, and the report suggests that *FERC* step into the currently vacant

FERC/Federal News

role of coordinating local, state and national planning efforts, convening stakeholders and establishing frameworks for evaluating OSW transmission options. Referencing FERC's Advanced Notice of Proposed Rulemaking (*RM21-17*) focused on transmission planning and cost allocation, the report envisions improved coordination that would promote more streamlined and consistent transmission planning.

Exactly how realistic that vision is remains uncertain. The report's release also coincided with the end of a 75-day comment period on the ANOPR. The commission received 165 comments from stakeholders ranging from RTOs and ISOs to utilities, developers and industry associations. (See *FERC Tx Inquiry: Consensus on Need for Change, Discord Over Solutions*.)

A key theme across many comments was opposition to any "one-size-fits-all" solution, instead calling for engagement with state regulators and policy makers in the transmission planning process.

While recognizing the need for reform, the National Association of Regulatory Utility Commissioners (NARUC) said "the commission should not lose sight of the need to ensure that all potential transmission planning reforms explicitly recognize the essential role states, and state laws, play in this process."

The National Conference of State Legislatures (NCSL) called for a "coordinated effort between FERC and states in the development and implementation of any regulatory change, including devising improved mechanisms to bring state legislatures into the energy decision-making process as full participants on an ongoing basis."

Looking at potential models for future planning, the report points to New Jersey's state agreement with *PJM*, under which the RTO will incorporate the state's goal of 7,500 MW of offshore wind into its regional planning process.

It also cites onshore wind planning in Texas, where the Public Utilities Commission and *ERCOT* worked together on the development of renewable energy zones and the necessary transmission buildout.

Co-existing with Fisheries and Marine Life

Attacking the challenges of offshore wind development on all fronts, the DOE on Wednesday also *announced $13.5 million* in funding "to provide critical environmental and wildlife data to support offshore wind development." The money will go to four projects, "that will inform offshore wind siting [and] permitting and help protect wildlife and fisheries as offshore wind deployment increases," the announcement said.

"In order for Americans living in coastal areas to see the benefits of offshore wind, we must ensure that it's done with care for the surrounding ecosystem by co-existing with fisheries and marine life — and that's exactly what this investment will do," Energy Secretary Jennifer Granholm said in the announcement.

Duke University received more than half of the funding — $7.5 million — for a project that will assess and monitor the impact of offshore wind development on birds, bats and other marine mammals. ■

FERC/Federal News

NAGF Speakers Highlight Resource Mix, Cyber Challenges

Three-day Conference Focuses on Multiple Reliability Risks

By Holden Mann

Speakers at the North American Generator Forum's (NAGF) Virtual Compliance Conference last week repeatedly urged grid planners to take seriously the challenges of the changing resource mix and other threats to the reliability and security of the grid.

NERC Board Chair Kenneth DeFontes | *NAFG*

In his keynote remarks on the first day of the meeting, NERC Board of Trustees Chair Kenneth DeFontes praised NAGF for its "longstanding partnership with NERC" and the "tremendous input and support" it has recently provided as the ERO sought to manage the myriad emerging threats to bulk power system reliability.

Citing the *2021 ERO Reliability Risk Priorities Report* published in August, DeFontes emphasized that grid transformation remains one of the most pressing risks facing the ERO Enterprise. (See *Grid Transformation, Cybersecurity Lead 2021 ERO Risk Report*.) He warned utilities that they may not be taking the challenges of the transition to renewable resources seriously enough.

Two recent reports lent weight to DeFontes' concerns. The first was NERC and FERC's joint inquiry into February's winter storm that led to unprecedented outages in the Midwest and left hundreds dead in Texas (*AD21-28*). The final report has not yet been released, but preliminary findings and recommendations were presented at the commission's open meeting last month. (See *FERC, NERC Share Findings on February Winter Storm*.)

The second report was NERC and ERCOT's review of an incident earlier this year in which multiple solar and wind facilities near Odessa, Texas, suffered voltage reductions. (See *NERC-ERCOT Report Reviews Texas Solar Issues*.) In both incidents, investigators found that entities had not implemented recommendations in NERC's nonbinding reliability guidelines despite widespread knowledge of their existence and the reasons for them.

"As we learned in the February cold-weather report, there can be dire consequences when guidelines are not followed. I am concerned that we're seeing a similar trend when I look at the Odessa disturbance report," DeFontes said. "We see the industry is well aware of the guidelines; they have considered them and adopted some parts of them; but they are not widely and comprehensively being followed, which has left us with potential reliability gaps."

Noting that FERC Chairman Richard Glick and NERC CEO Jim Robb have promised that the winter storm report "will not sit on the shelf," DeFontes urged utilities to study the Odessa disturbance report and make a real effort to apply its lessons. He promised that if nonbinding guidelines prove to be insufficient, NERC will "move forward to improve [mandatory] standards."

Gugel, Lauby Emphasize Changing Grid Conditions

Howard Gugel, NERC's vice president of engineering and standards, continued the discussion of the changing grid in his presentation. Comparing predictions NERC made in 2008 of fuel mix changes over the next 10 years versus the actual conditions in 2017, Gugel observed that natural gas, wind, solar and nuclear all increased more than expected — gas and wind grew more than four- and threefold, respectively — while coal's presence in the BPS actually declined, rather than rising as NERC had anticipated.

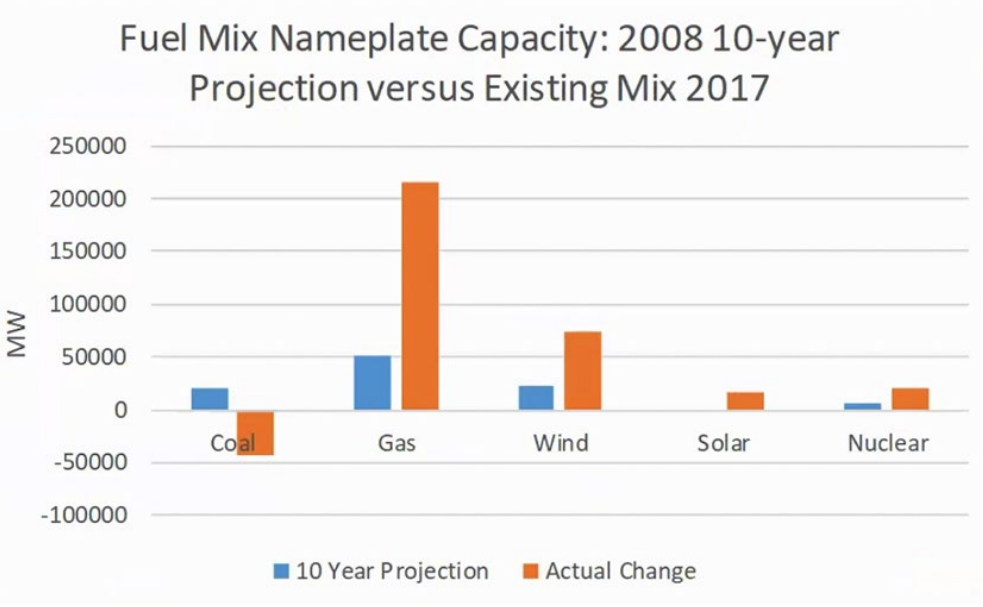
The growing presence of weather-dependent resources such as wind and solar — along with behind-the-meter resources like rooftop solar, home battery storage systems and grid-connected electric vehicles — poses a problem for system planners, who will "have to become very creative in understanding [the] differences" between these generators and traditional resources.

"Our system was not designed or planned with that in mind, but that reality is coming," Gugel said. "The question is, how do you adapt for that? How do you become resilient?"

Gugel identified several problems that planners are going to have to solve, including a lack of transparency into current load and status of behind-the-meter resources; inability to quickly ramp up generation among wind and solar resources in the event of an emergency; voltage regulation; and underfrequency load shedding. All of these will require a level of communication that prior generations never anticipated.

Mark Lauby, NERC | *NAFG*

NERC Chief Engineer Mark Lauby concurred with Gugel's warning about the assumptions underlying traditional



NERC's projected 2017 nameplate capacity in 2008 compared to the actual resource mix in 2017 | *NAFG*

FERC/Federal News

BPS planning, saying that "that world is slowly disappearing" and that establishing essential reliability services is becoming much more difficult in a world of distributed, smaller, asynchronous generation resources that require much more automation to manage remotely and programming to "ride through minor system disturbances so as not to make them worse."

The increasing reliance on electronic grid management systems also means that the BPS must be hardened against cybersecurity threats, Lauby observed. Noting recent cybersecurity events like the SolarWinds and Microsoft Exchange Server attacks, he observed that hackers "are not dumb; they are persistent," having learned how to target a wide range of industries.

"So far, fortunately, we haven't really seen a breach from [information technology to operational technology], though we have had vulnerabilities we've identified and are working to address them," Lauby said. "But as we start digitizing more … we're going to have to keep in mind that we design a system that's robust against those kinds of attacks … so that we're not as much of a target."

SERC Shares Self-report Tips

The meeting also featured presentations from other stakeholders, including Janice Carney, senior compliance engineer at SERC Reliability. Carney discussed the importance of self-reporting potential violations of NERC reliability standards, observing that bringing potential compliance issues to a regional entity's attention voluntarily is "a much better position for an entity to be in compared with a noncompliance found during an audit."

Information needed in self-reports includes the date of discovery; start and end dates of the noncompliance, with a basis for each; a description of how the infringement was identified; the number of people, devices or systems involved in the noncompliance; the cause of the violation; and prior instances of noncompliance with the same standard.

Carney also emphasized the importance of writing style in self-reports, urging utilities to be as clear as possible by using active voice rather than passive and defining all acronyms on first usage.

Cold Weather Plans Coming Soon

Finally, Venona Greaff, manager of compliance at Occidental Energy Ventures, updated attendees on the new reliability standard *EOP-011-2* (Emergency preparedness and operations), approved by FERC in August, and its requirement that generator owners implement plans to protect their units from freezing. (See *FERC Approves Cold Weather Standards*.)

"As generators, when we think about these standards and how they fast-tracked them after the February [winter storms], it seems like it's a steam engine barreling down on us at a great pace," said Greaff, who served on the standard drafting team for EOP-011-2 and the other cold-weather standards.

"But in reality, this has been coming for a long time," she continued, noting previous cold-weather events that occurred in 2011, 2013 and 2018 — the last of which was the impetus for the cold-weather standards project. (See *FERC Orders Cold Weather Reliability Standard*.)

While the new standard will not take effect until April 2023, Greaff's presentation was aimed at providing utilities a basis for starting to develop their plans, including basic attributes such as a purpose statement explaining what the procedure is meant to do and the applicable entity or facility; the personnel who will be responsible for specific activities, as well as for oversight of the entire plan; and critical components and instrumentation that need priority protection.

"One thing I want to remind you [members] of the NAGF is, collaboration and assistance is always an option," Greaff said. "We currently have a cold-weather preparedness group [that] has 82 members. … I think that we have a lot that we can share with each other, and we can learn from each other in this working group. So I'd encourage you to think about joining the working group. It doesn't mean that you have to take a lead role; it just puts you in that small group and allows you to be a part of the conversation." ■

Southeast

SEEM to Move Ahead, Minus FERC Approval

Deadlocked Commission Means Agreement Effective Oct. 12

Continued from page 1

and criticism from its opponents.

The agreement became effective "by operation of law" because FERC had failed to take action by Oct. 11, 60 days after SEEM's supporters — a consortium of electric utilities including Southern Co., Dominion Energy South Carolina, Louisville Gas & Electric, the Tennessee Valley Authority and Duke Energy — filed their response to the commission's latest deficiency letter. (See *SEEM Members Push for FERC's Decision on Market Proposal*.)

With commissioners "divided two against two as to the lawfulness of the change," the measure automatically took effect in accordance with *Section 205* of the Federal Power Act. It is the second time in two months that a deadlocked FERC allowed approval of a proposal, after the passage of *PJM*'s minimum offer price rule in September (*ER21-2582*). (See *FERC Deadlock Allows Revised PJM MOPR*.)

SEEM supporters issued a *release* Wednesday promising the platform would be operational by the middle of next year. The release listed a number of "founding members of SEEM" in addition to Duke, Southern, TVA and Dominion. Some utilities that have not yet made "firm decisions" are expected to do so as a result of the FERC ruling, and membership is open to any additional entities that meet the requirements.

A decision on SEEM was expected at the commission's most recent open meeting, where the proposal was on the agenda, but the item was removed at the start of the meeting. FERC's statement Wednesday did not reveal which commissioners supported the proposal. Commissioners are required by the FPA to provide written statements explaining their views, but the law does not specify when they must do so. So far, none of the commissioners have done so regarding the PJM MOPR decision.

Currently the commission has two Democratic members and two Republicans; President Joe Biden nominated D.C. Public Service Commission Chair Willie Phillips to fill the seat vacated by Republican Neil Chatterjee in August. (See *Biden to Nominate Phillips to FERC*.)

Critics Warn of Entrenching Current Winners

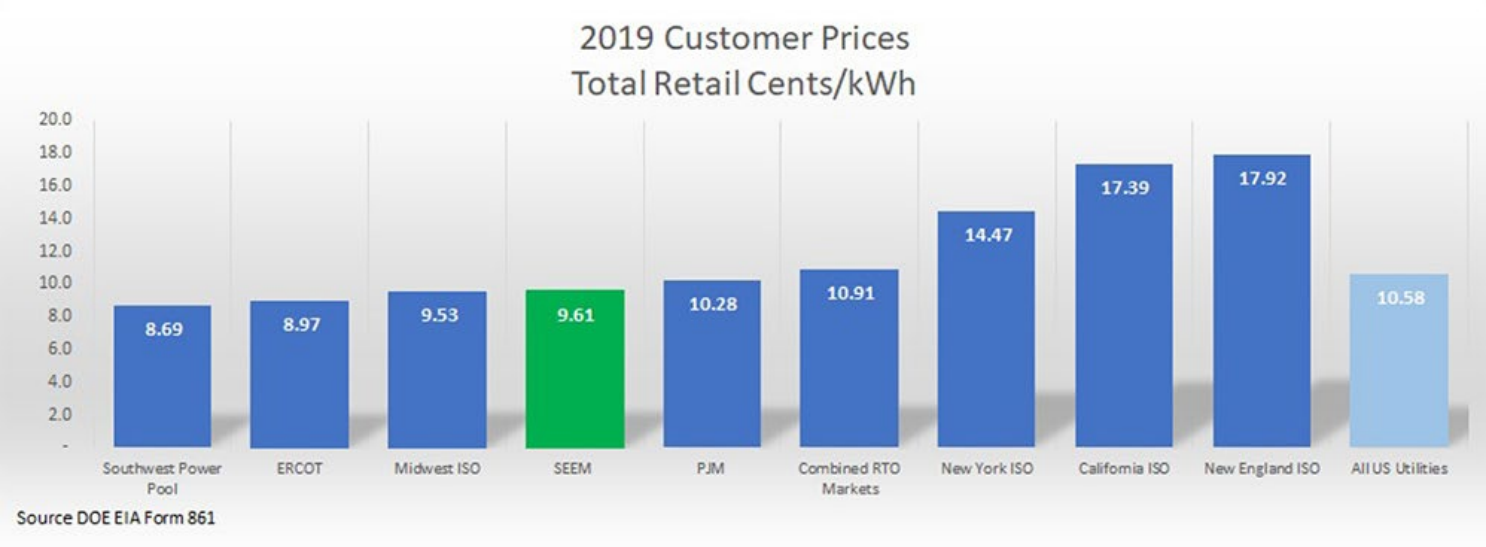
SEEM's supporters submitted the proposed agreement to FERC in February, promising that the planned expansion of bilateral trading in 11 Southeastern states would reduce trading friction while promoting the integration of renewable resources. The proposal is intended to reduce trading friction by introducing automation, eliminating transmission rate pancaking, and allowing 15-minute energy transactions.

Criticism has dogged the project from the start, with opponents skeptical of the promises of its supporters. In multiple filings to FERC, a collection of environmental groups, including the Sierra Club, the Southern Alliance for Clean Energy, the North Carolina Sustainable Energy Association, and the Southern Environmental Law Center (SELC), warned that SEEM would allow transmission-owning utilities to "favor their own generated electricity and to exclude competitors from the market." (See *SEEM Critics Repeat Call for Technical Conference*.)

In addition, a September *report* by the *American Council on Renewable Energy (ACORE)* suggested that other models surpassed the supposed benefits of SEEM. The report simulated SEEM against three alternative energy market models in the same footprint and found that all three outperformed SEEM in terms of financial savings, integration of renewable energy resources, and reduction in carbon emissions over 20 years. (See *Report: SEEM's Benefits Beaten by Other Models*.)

Following FERC's announcement, SELC attorney Maia Hutt called SEEM's supporters "some of the largest monopoly utilities in the country" and stressed that "SEEM … cannot be the last step towards wholesale market reform in the Southeast."

Gizelle Wray, director of regulatory affairs and counsel at the *Solar Energy Industries Association (SEIA)*, said in a statement that the proposal was "not a real market," and would merely help "entrenched monopoly utilities" to con-



Average retail prices for utilities in SEEM versus the RTO markets. | *SEEM*

Southeast

solidate their power.

"We need a true market that encourages new entrants and competitive bidding, all of which could help bring Southeast utilities into the 21st century. We are in a race against the clock on climate change, and structures like SEEM will only hinder our progress," Wray said. "This decision is a clear sign of what can go wrong when there's a 2-2 split on FERC and proposals go into effect by law. We urge the Senate to quickly confirm [Chairman Phillips] so we can have a fully functioning commission."

Changes Promised After Deficiency Letter

Given the way the SEEM proposal was approved, it is not clear whether supporters will follow through on the changes they promised in a filing in June. FERC sent SEEM organizers a deficiency notice in May, submitting 12 detailed questions about how the plan to automate matching buyers and sellers would operate. In response, proponents suggested several modifications to the agreement, including:

- confidential weekly submissions of market data to FERC and the market auditor.
- disclosure of regulators' questions and answers, as well as market auditor reports, to participants, subject to restrictions on access to confidential information by marketing function employees.
- a clarification that available transfer capability calculated by participating transmission providers must be provided to the SEEM administrator and must be used in the algorithm for each leg of any contract path to ensure transmission will not exceed available capacity.
- making the "just and reasonable standard" the default for most SEEM rules rather than the lower Mobile-Sierra public interest standard. (See *SEEM Members Offer Rule Changes*.)

SEEM's release on Wednesday made no mention of these changes, only thanking FERC and its staff "for their thorough review" and pledging to follow "all FERC-approved rules and requirements for existing bilateral markets today, but with additional transparency." Advanced Energy Economy, a national association of companies promoting clean energy and electrified transportation, *warned* that the lack of a FERC order "allows the sponsoring utilities to move forward without any commission direction" on implementation or transparency. ■

CAISO/West News

Talk of Western RTO Intensifies

CAISO and BPA Sticking Points in Regionalization

By Hudson Sangree and Robert Mullin

The debate over a Western RTO has ramped up this month, with discussions focused on the feasibility of an organized market in the West, its pros and cons, and its potential makeup, including whether California's participation is necessary for success.

Stakeholders and state regulators weighed those factors at a CAISO *forum* Wednesday and in an Oregon RTO Advisory Committee *meeting* Oct. 6. This week's *joint meeting* of the Committee on Regional Electric Power Cooperation and the Western Interconnection Regional Advisory Body (CREPC-WIRAB) includes an afternoon of panels devoted to the topic, as well as other panels and presentations by FERC commissioners touching on it.

The growing sense of urgency is being driven by state decarbonization mandates, resource adequacy problems and state laws requiring utilities to join RTOs. (See *Western Utilities to Explore Market Options*.)

"There's been a convergence of interest in these issues like there has never been before, and I think that's a very, very good thing," California Public Utilities Commissioner Clifford Rechtschaffen said during CAISO's forum. "People are really focused on regional markets, the need for robust rules for resource adequacy and shared reliability efforts. How do we achieve clean energy mandates across the West now that more and more states have gone that way?"

Rechtschaffen called it an "opportune time" for regionalization efforts in the West.

The forum was primarily focused on the ISO's proposal to expand its Western Energy Imbalance Market from an interstate real-time trading platform to an extended day-ahead market (EDAM), a potentially significant step for Western regionalization. But discussion of the EDAM and the Northwest Power Pool's creation of the interstate Western Resource Adequacy Program (WRAP) led to talk of a Western RTO. (See *CAISO Promotes EDAM Effort in Forum*.)

"An RTO market is no panacea," said Tony Braun, an attorney who represents the California Municipal Utilities Association. "For those that are in one, if you want to talk about funding of financial transmission rights by load and other things that are quite controversial, call me offline. We can talk about it. I think people underestimate the obstacles and, even within an RTO structure, the ongoing struggles of operating within that paradigm."

State regulators and industry representatives weighed in on EDAM and Western markets. | *CAISO*

EDAM, WRAP and the possibility of an RTO are all under consideration, and "I think we just need to tackle them all at the same time," Braun said.

"I don't them see as mutually exclusive, but I do see EDAM as low-hanging fruit. There's so much work that has been put into EDAM … that it would not be prudent to abandon it just because there's a myriad of other options. We have to walk and chew gum on this at the same time, maybe a couple different flavors of gum."

Spencer Gray, executive director of the Northwest & Intermountain Power Producers Coalition (NIPPC), called EDAM a worthwhile initiative but said "it can't be the end goal of further regionalization." EDAM and WRAP are incremental approaches that don't adequately address the clean energy mandates of a growing number of Western states, or the laws that Colorado and Nevada enacted in June requiring transmission owning utilities join an RTO by 2030, he said.

"I don't dispute that a staged approach to developing regional markets can help us move forward rather than just stalling out," Gray said. "But I do want to emphasize that we have both statutory and market pressures across the West that hang over this initiative."

California, New Mexico, Oregon and Washington have 100% clean energy mandates to meet by midcentury, he noted. Nevada established a 100% clean-energy goal it intends to reach by 2050.

"We also have large, sophisticated energy consumers across the West who are committed to going carbon-free, and many of them are convinced, based on actual experience procuring clean power in RTOs, that the model an RTO offers — of not having contract-based transmission anymore, not having pancaked rates, not having balkanized balancing authorities — [is] a better alternative."

He said he worried the EDAM may be an "incremental step that holds at bay harder conversations about governance and balancing authority consolidation and transmission."

SPP has been pitching its own RTO in the

CAISO/West News

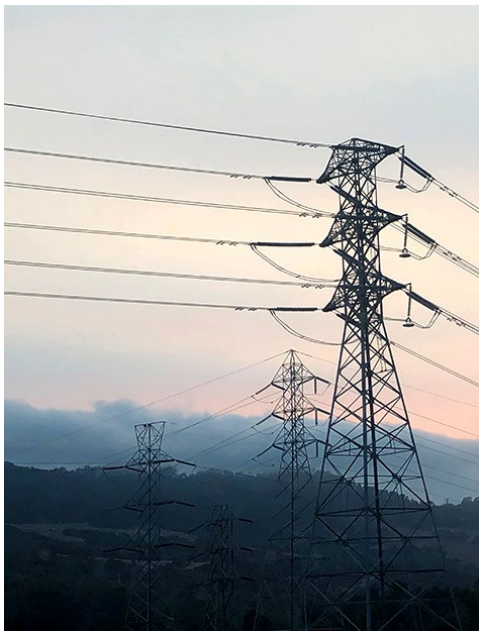
West. Gray called that a positive move that would allow entities to join an RTO without California having to give up control of CAISO, a state public benefit corporation created by the legislature, with board members appointed by the governor. Prior efforts to turn CAISO into an RTO have fizzled because California lawmakers were unwilling to cede any authority over it to out-of-state interests.

Joining SPP means utilities "can simply sidestep a brick wall of single-state governance that has bedeviled RTO conversations that have revolved around CAISO, so I think collectively we should take both the EDAM initiative seriously, take SPP's work seriously and try to pick the best course. And we may pick different courses, which is OK. That's been the experience along many seams in the East between the RTOs."

Is California Necessary?

Gray's comments and other discussions taking place in the West suggest industry stakeholders are weighing the need to create a workable RTO rather than an ideal one, forcing the region to consider the "art of the possible," as Oregon Public Utility Commissioner Letha Tawney put it during a recent meeting of the state's RTO Advisory Committee, which was charged with helping the state's Department of Energy prepare a report on the benefits and risks of RTO membership. (See *Oregon RTO Committee Ponders Paths to Regionalization*.)

That could translate into an effort that sidelines California, the region's most populous state, biggest load center and burgeoning center of cheap solar energy that can be exported to neighboring states during periods of surplus.



Lines operated by CAISO travel through the San Francisco Bay area. | © RTO Insider LLC

A recent state-led study produced by Energy Strategies found that all states in the Western Interconnection would realize the largest amount of savings — about $2 billion a year — from a single market that includes California, with the biggest beneficiaries being Washington, Oregon and California itself. (See *Study Shows RTO Could Save West $2B Yearly by 2030*.)

But integrating California into such a market is being seen as increasingly problematic as more states look to use RTO membership as one tool in meeting their decarbonization goals on ambitious schedules that will likely outpace the timeline for development.

Speaking during the Oct. 6 meeting of the RTO Advisory Committee, Tawney pointed to the well known governance issues that have hampered CAISO's regionalization efforts in the past, with many in-state interests reluctant to allow the state to relinquish its direct authority over the appointment of members of the ISO's Board of Governors. Resistance to changing that governance structure has made membership in an expanded CAISO a nonstarter for regulators in other parts of the West.

But just as problematic, Tawney noted, is California's approach to resource adequacy, a process managed not by CAISO but by the state's Energy Commission.

"It is unusual, but not unprecedented, to have your resource adequacy conversation happening in a different place than your RTO," Tawney said. "CAISO does it that way. ERCOT sort of does it that way. But I think because of how resource adequacy is handled in California, it makes it very difficult to sort of take the California RA model and spread it across the West. And so then we have the rest of the West say, 'How could we do RA for ourselves in a way that works for us?'"

Momentum toward a Western RTO could build after Colorado and Nevada passed bills requiring utilities in those states to join an RTO, Tawney said. She compared the potential outcome of that legislation to the expansion of the Western EIM, which eventually crowded out trading in the West's bilateral markets.

"Where does that leave Oregon customers?" Tawney said.

She acknowledged the Energy Strategies study finding that showed that the biggest market footprint would produce the greatest volume of economic benefits for the West.

"The flip of that is there's more people you have to work with and figure out how to get along with and manage through," Tawney said. "So, you have to find that sweet spot, from my perspective, between customer benefits and state policy."

What About BPA?

The situation in the Northwest is further complicated by the presence of the Bonneville Power Administration, which operates about 70% of the region's high-voltage transmission and manages its extensive network hydroelectric dams.

Speaking at the RTO Advisory Committee meeting, Northwest Energy Coalition policy analyst Fred Heutte noted that BPA's "integrated system" relies on a contract-based — rather than flow-based — approach to transmission use.

"I think it's easy to say [that], in an RTO, you can move to a flow-based approach and it's all going to be great," Heutte said. "But we have to look at Bonneville as a unique institution with a really important role, and trying to move from a contract-based approach to a flow-based approach, given Bonneville's integrated approach, is going to be a big issue to have to unravel and kind of piece together how you do that transmission.

"It's not just a matter of grandfathering rights and that sort of thing," Heutte said. "The Bonneville system has some unique features that we have to consider in the transition to an RTO process."

During the RTO Advisory Committee's first meeting Sept. 21, BPA Manager Ravi Aggarwal encouraged the group to consider a "staged and incremental" approach to developing an RTO, saying the region's transmission planning, RA and real-time market are already being served by Northern Grid, NWPP and the Western EIM, respectively.

Speaking at the Oct. 6 meeting, Aggarwal clarified that he was not advocating for the long-term persistence of those looser arrangements in lieu of an RTO but thinks they could provide a "pathway" to an organized market, whether West-wide or in a smaller footprint, such as that covered by the NWPP.

"I think we have to be careful about holding out a perfect RTO as a possibility — or maybe an Eastern-style RTO maybe is the way to put it — because we aren't starting with a blank slate," Tawney said. ■

CAISO/West News

CAISO Promotes EDAM Effort in Forum

ISO Wants to Expand Western Energy Imbalance Market to Day-Ahead

By Hudson Sangree

CAISO ramped up efforts Wednesday to expand its Western Energy Imbalance Market from a real-time to a day-ahead market in a virtual *forum* that brought together utility CEOs, regulators and industry leaders to discuss the plan.

The ISO paused its proposal for an extended day-ahead market (EDAM) after the rolling blackouts and strained grid conditions in August and September 2020. Now back in play, the EDAM faces a more crowded field of efforts to coordinate pieces of the West's energy markets or to establish a Western RTO.

"This is an extraordinarily dynamic, challenging and exciting time in the West," CAISO CEO Elliot Mainzer said as he opened the session with 400 attendees. "Everyone seems to be talking about and working with a sense of real urgency towards greater regional coordination and market integration."

Recent efforts include the Northwest Power Pool's work to form the Western Resource Adequacy Program, SPP's creation of the Western Energy Imbalance Service and its pitch to lead a Western RTO, and the formation of a Western Markets Exploratory Group (WMEG) to consider coordinated market services such as transmission expansion and day-ahead energy sales. (See *Western Utilities to Explore Market Options*.)

FERC Chairman Richard Glick has called for establishment of one or more Western RTOs, and Nevada and Colorado passed laws this year ordering their transmission-owning utilities to join an RTO by 2030.

"I have never seen or felt a greater sense of interest and urgency on this topic," Mainzer said.

CAISO hopes to play a central role in Western regionalization with the EDAM.

The steady expansion of the Western Energy Imbalance Market (WEIM) since its founding in 2014 has demonstrated the value of a real-time market in the West, Mainzer said. The WEIM has generated more than $1.4 billion in benefits for its 15 participants. Six more entities plan to join by 2023, spreading the market's footprint across nearly all Western states and encompassing 84% of electricity load in the West.

"The growth of the EIM has provided tangible evidence that the West does best when we optimize transmission and resource diversity across the widest geographical footprint possible," Mainzer said. "And given the level of interest and desire for actionable progress towards a fully integrated market or RTO in the West, we are now prepared and excited to build on the foundation of the EIM and reinitiate our extended day-ahead market stakeholder initiative."

'Next Major Step'

Mainzer moderated a panel of CEOs from some of the West's largest utilities, most of whom praised the effort.

"For us at PacifiCorp, the extended day ahead market builds on the solid foundation of the Energy Imbalance Market," said Stefan Bird, CEO of PacifiCorp subsidiary Pacific Power. Participating in the WEIM has saved PacifiCorp $310 million and reduced its carbon output by 5 million metric tons, he said.

"While the EIM has been hugely successful, it only scratches the surface of what's possible," Bird said. "As we now look to the next incremental step in our market partnership with the California ISO and other participants, we see the extended day-ahead market as the next big opportunity to increase customer benefits by optimizing an even larger volume of energy transaction and fuel commitment decisions that occur in the day-ahead and real-time operations."

The West's diversity of solar, hydropower and geothermal resources, along with time differences in the region's vast geography, create an ideal situation for maximizing use of clean energy resources, he said.

The CEOs of PG&E Corp., Southern California Edison, NV Energy, Idaho Power and Seattle City Light also took part in the panel and endorsed continuing with the EDAM stakeholder process.

The EDAM proposal met with some criticism last year before it was put on hold. Some stakeholders complained that, under a July straw proposal, the EDAM would not be as wholly voluntary as the WEIM and would require ceding transmission rights. The ability of entities to participate with few obligations and to leave at will has been a major selling point of the WEIM. (See *EDAM Design Could Undermine Tx Rights, Critics Say*.)

CAISO CEO Elliot Mainzer opened Wednesday's forum. | *CAISO*

This summer, with the EDAM plan on hiatus, a working group of stakeholders met to discuss EDAM design.

"The objective of the work group was to facilitate the restart of the general EDAM stakeholder process by reflecting areas of common agreement and understanding among the parties," said a document titled *EDAM Common Design Principles and Concepts*, included in Wednesday's forum materials.

Participants agreed that the EDAM should continue the WEIM's "concepts of voluntary entry … and no-penalty exit that have worked extremely well for the EIM." They also agreed EDAM participants should "maximize the amount of transmission (firm, or otherwise high priority) made available to EDAM" but that the market should respect existing open-access transmission tariff frameworks and contractual commitments.

The EDAM *stakeholder process* calls for market design, implementation and testing to continue through 2022 and 2023 with the goal of going live in 2024.

Mainzer said hurdles will include technical and governance issues. Working through those will allow the EDAM to resolve reliability challenges facing the West as California and a growing number of states enact clean energy mandates, he said.

"We are very motivated and committed to position EDAM as the next major step towards West-wide market integration as we all drive for greater reliability and affordability in achieving our energy policy goals," Mainzer said. ■

CAISO/West News

CEC Puts $24M Toward Electric Buses, Trucks

Los Angeles Aims to Electrify Entire Public Transit Bus Fleet

By Hudson Sangree

The California Energy Commission allocated a major round of funding Wednesday to support the development of electric transit buses, school buses and medium- and heavy-duty electric trucks as the state tries to decarbonize its transportation sector.

The nearly $24 million in funding included a $6 million grant to the Los Angeles Department of Transportation to continue electrifying its transit bus system. The grant will enable LADOT to add a solar-plus-storage microgrid to provide clean energy and keep its electric bus fleet running, even during power outages. It will also fund four 1.5-MW chargers, 104 charger dispensers and overhead transit bus charging with solar canopies.

"The project will deploy electric bus charging infrastructure to support up to 142 battery electric buses," Energy Commission Specialist Esther Odufuwa said. "LADOT's strategy is to convert its entire fleet of buses to battery-electric zero-emission vehicles."

The microgrid project, in a city as immense as Los Angeles, can serve as a model for smaller cities, Odufuwa said. There are approximately 11,500 transit buses operating statewide, she added.

"This microgrid technology has the potential to be completely replicable for all transit agencies in California, regardless of their of their size," Odufuwa said.

If the state were to convert all transit buses to electric vehicles and operate them as bidirectional resources, they could discharge up to 700 MW of flexible capacity to support the state's grid reliability efforts — enough electricity to power 700,000 homes, she said.

Commissioner Patricia Monahan, the lead commissioner for CEC transportation programs, said "this project has it all in terms of … electrifying buses and doing it in a way that's attentive to the grid. We are really looking for those twofer opportunities where we get a benefit to the grid and a benefit to the transit district."

The item passed unanimously.

The CEC also approved a $13 million grant to the nonprofit Electric Power Research Institute to fund a research hub focused on electric heavy-duty drayage trucks. Cal Start, a research and development organization for clean transportation, will act as a major subcontractor on the project.

"The research hub will advance high-power charging technologies and engage a broad network of stakeholders and communities to deploy public-access charging infrastructure for [medium- and heavy-duty] vehicles in heavily trafficked freight corridors," the project description said.

The CEC gave eIQ Mobility, which provides fleet electrification services, $2.2 million to fund a demonstration project for bidirectional electric charging of school buses in the San Francisco Bay area.

A $1.7 million grant will fund the deployment of 300-kW wireless charging infrastructure for the SolanoExpress intercity bus service in Solano County in Northern California.

Smaller grants will fund planning for medium- and heavy-duty vehicle electric charging and hydrogen refueling stations and to develop a zero-emission transportation program for the 2028 Olympic Games in Los Angeles. ■

Los Angeles received a $6 million grant to electrify its transit buses. | *LA Metro*

ERCOT News

New ERCOT Board Approves Governance Changes

By Tom Kleckner

ERCOT's Board of Directors meets Oct. 12. | *ERCOT*

ERCOT's newly reconstituted Board of Directors met for almost 20 minutes Oct. 12 morning, enough time to share congratulatory messages and approve *amendments* to the grid operator's bylaws incorporating the state legislation that remade the board in the first place.

"That was painless," an anonymous stakeholder or staff member said just before the video stream ended.

Board Chair Paul Foster and Director Chris Aguilar were only in the 10th hour of their three-year terms when the board meeting began. They are the first two of eight independent directors who will eventually comprise the 11-person board. (See *2 New ERCOT Directors Named, Replacing Current Board*.)

"You've been much anticipated, both of you," interim CEO Brad Jones told them. "ERCOT staff has long wanted this new board in place."

Revamping ERCOT's board, which previously consisted of five independent directors and eight market segment representatives, became one of the legislature's top priorities after February's winter storm drove the Texas Interconnection to the brink of collapse.

"I know I have a lot to learn, but I'm looking forward to working with all of you," said Foster, who comes from an oil sector background.

"What brings us here is what we most fear: the small probability of an event that can have catastrophic consequences. That is what we have to prevent," Aguilar said.

The board will meet later this month to consider voting items that were deferred Oct. 12 and to ratify the meeting minutes from the board's previous 18 months of virtual meetings. The Finance and Audit and HR and Governance committees will meet before that while it waits for the other six members to be selected. (See *Search Firm Chosen to Find New ERCOT Board Members*.)

Jones, Public Utility Commission Chair Peter Lake and the Office of Public Utility Counsel's Chris Ekoh also sit on the board, with only Ekoh allowed to vote. ■

ERCOT News

ERCOT's Jones Looks Ahead, not Behind

Grid Operator's CEO Focused on Rapidly Changing Market

By Tom Kleckner

HOUSTON — Introduced as "clearly a man of courage and conviction to take this job at this time," interim ERCOT CEO Brad Jones stepped up to the speaker's podium and briefly rehashed February's events that led to his leadership position with the Texas grid operator.

"The media said we weren't prepared [for the February winter storm]. That's not true," he told an in-person and virtual audience Thursday during the University of Texas School of Law's Gas and Power Institute.

Referencing a similar winter event that led to suggested weatherization recommendations, Jones added, "The generators were prepared, but to 2011 standards."

But rather than revisit history, Jones made it clear his focus is on what lies ahead.

"The future of ERCOT depends on more than our response to the winter storm. It depends on our response to an extraordinarily fast-changing market," he said.

Speaking without notes, Jones said his 60-point *roadmap to grid reliability*, given homepage prominence on ERCOT's website, addresses the grid operator's concerns "today and tomorrow." Twenty-nine of the roadmap's items have been completed, with all but one of the remaining 31 listed as being "on track." (Placing senior-level representatives from each member organization on the Technical Advisory Committee has been delayed until the new Board of Directors is fully in place.)

"The seeds of what we want to fix are in the [February] problems," he said. "Weatherization has to improve. We can't rely on 2011 standards. The weather is not waiting for the PUC to get [its] rules in place. 'Winter is coming,' as we've all heard."

Jones said he has been contacted by generation owners who told him they are investing "tens of millions of dollars" in weatherizing their facilities. "They're investing because they see where the weather is going and they need to get ahead of it," he said.

ERCOT staff this November will begin inspecting nearly 300 generating units' weatherization, concentrating on those responsible for the 80% of lost megawatts from the February storm. The grid operator is staffing up for the effort, which includes filing a report with the Public Utility Commission.

Interim ERCOT CEO Brad Jones shares his thoughts with a pair of attendees to UT Law's Gas and Power Institute. | *© RTO Insider LLC*

"I hope gas suppliers are moving forward, just like the generators," Jones said. The FERC-NERC joint inquiry on the storm and other reports have all placed most of the blame for generation outages on the lack of natural gas supplies. Texas politicians have found the gas industry's response to be lacking. (See *Texas Senators Call for New RRC Weatherization Rules*.)

Noting ERCOT's interconnection queue is heavily weighted in favor of renewable energy projects, Jones said their "extraordinarily valuable" low prices need to be balanced with more reliable generation. He brought up the RACE acronym he often uses with the public: reliable, affordable, clean electricity.

"For too long, it's been CARE. We've got to put the R back in front," Jones said. "One of the things the state has failed to do over the last 20 years is to put reliability first."

Jones said ERCOT would like to see "stout" firm fuel contracts, dual-fuel capabilities and underground storage to ensure thermal plants have a reliable fuel supply. Citing rising gas prices, he also said he wants to separate generation from relying on natural gas, should the power equation's gas side again fail during extreme weather.

"We want to ensure there's language in the contracts to firm them up as much as possible and to give them some teeth to ensure reliable delivery," Jones said.

Asked whether a capacity market would have resolved ERCOT's problems during the winter storm, Jones said he is a fan of capacity markets and that they work "very well."

"The problem is, it takes so much time to tune the rules and change things to drive certain outcomes," he said. He used PJM's capacity market as an example of a market that "drives the type of reliability we need" with its firm-fuel requirements.

"It's also true that we can build those same tools outside of a capacity market," Jones said. "It's not necessarily true that a capacity market would have saved us. We had the capacity; it just didn't operate."

A capacity market would have helped in the billions of market charges assessed to

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participants in the two days after the storm subsided, Jones said. During that time, the PUC kept market prices at $9,000/kWh to encourage generation to stay online. He said capacity markets typically have $1,000 offer caps because capacity resources are paid on an annual basis.

"The financial storm would have been little more than 1/10 of what actually occurred," Jones said.

The scars from February still remain. Jones said during a recent call with North Texas mayors, he was asked about the likelihood of another winter storm in 2022. Calling February's a one-in-130 year event, he said one could assume a 1% chance of a similar destructive storm. However, weather forecasters have also said there's a higher likelihood of another winter event the year after another one, Jones said.

"So not a 2021, but perhaps a 2011 storm," he said, placing the chances in the 10-15% range. "We have to be prepared for something like that … and we are getting ready. I feel very confident we will be ready."

Uncertainty for ERCOT Board, Market

Two energy lawyers both expressed uncertainty about changes to ERCOT's governance structure and market design.

Meghan Elaine Griffiths, an attorney with Jackson Walker, said a questioner's guess "is as good as mine" when queried about how the political appointees to the ERCOT board will affect the market and stakeholder process. Under new legislation passed earlier this year, the board's structure of unaffiliated directors and market segment representatives has been replaced by a selection committee's appointees, with the committee itself selected by the state's political leadership. (See *2 New ERCOT Directors Named, Replacing Current Board*.)

"One of the benefits of having market stakeholders on the board is they have a deep knowledge of the business and a deep knowledge of the protocols as they're developed," Griffiths said. "I think there's a very steep learning curve for our new ERCOT board members. We'll see how that plays out over time."

Already, one media report has highlighted board Chair Paul Foster's tie to Republicans. *According* to *The Dallas Morning News*, Foster has since June donated $1.775 million to Gov. Greg Abbott's campaign committee.

Michael Nasi, a partner with Jackson Walker, shared a quote on market design from PUC Chair Peter Lake before the State Legislature: "'I want to reassure you that we are not tweaking on the edges or making marginal

Brad Jones explains ERCOT's future concerns to UT Law's Gas and Power Institute. | © *RTO Insider LLC*

changes. We are taking a blank-slate approach for a full overhaul and redesign of this market to drive reliability. Full stop.'"

"This market has been cited as the envy of many and potentially modeled in many places in this country and around the world," Nasi said, referring to pre-February perspectives. "And then to have Chairman Lake say we're going to fundamentally redesign this … I welcome the change, but how does it get done? It will be hard work, but it's doable. ERCOT can still be a model for others." ■

ISO-NE News

NEPOOL Markets Committee Briefs

WESTBOROUGH, Mass. — Continued discussion of eliminating the minimum offer price rule (MOPR) from ISO-NE's capacity markets and Order 2222 compliance took up a sizeable portion of the agenda during a two-day, in-person meeting last week of the NEPOOL Markets Committee.

The New England Power Generators Association and Advanced Energy Economy laid out their complaints with the RTO's proposals at the session, the first in-person meeting of the MC since March 2020 because of the COVID-19 pandemic.

ISO-NE Proposes Review Mechanism

As part of its MOPR elimination, ISO-NE *proposes* a narrow, buyer-side market power review mechanism where new capacity resources qualified to participate in an upcoming Forward Capacity Auction will follow one of three lanes:

- de minimis lane
- supported purpose lane
- full assessment lane

New resources with a qualified capacity below a de minimis size threshold — yet to be determined — enter that lane and will not be reviewed for buyer-side market power. The RTO's tariff presently provides de minimis exemptions to certain supply-side market power reviews. The threshold will similarly focus future buyer-side market power reviews on larger new resources. As a result, ISO-NE anticipates that a de minimis threshold will likely exempt most new capacity resources currently subject to review under the MOPR.

All remaining resources — small in number but constituting most of the new qualified capacity offered in the Forward Capacity Market — would need to proceed down the supported purpose or full assessment lanes.

A new capacity resource that can demonstrate that it meets certain criteria — such as the absence of any load-side interest or arrangement or that it is a development to meet a specific state regulatory requirement or policy — would go down the supported purpose lane and will not need further evaluation by the Internal Market Monitor. This will allow resources built to further state decarbonization goals and contribute to the region's capacity supply to participate in the Forward Capacity Market, which is consistent with the overall objective of the MOPR's removal, ISO-NE said.

New resources that do not qualify for the de minimis or supported purpose lanes will undergo a more thorough buyer-side market power evaluation by the IMM. In addition, those resources must comply with the new certification requirement, which requires an affidavit stating that they are not participating in the auction to reduce the clearing price. They may be required to provide project-specific confidential information to facilitate an assessment of buyer-side market power and mitigation.

Bruce Anderson, vice president of market and regulatory affairs for the New England Power Generators Association (NEPGA), said in a *presentation* to the committee that ISO-NE's MOPR elimination proposal "allows for uncompetitive rates and fails to create a proper balance between consumer and investor interests" in the FCM.

Under the ISO-NE mitigation proposal, new capacity resources may be offered at any price, whether competitive or not, eliminating the critical relationship between competitive offers and competitive rates, NEPGA said.

If the RTO eliminates the MOPR at all, NEPGA said it should be done at the same time as it enacts "capacity accreditation reform and meaningful forward reserve pricing."

NEPGA said ISO-NE has acknowledged its MOPR elimination proposal would create "a greater risk of inefficient retirements" and "gaps" in the wholesale markets that the generators said must be fixed by the accreditation and forward reserve changes.

"Delaying the remedies for the two existing gaps in the wholesale markets, while creating a third issue to be remedied, is poor planning and should be avoided through the concurrent application of these wholesale market design changes," NEPGA said.

NEPGA also said that ISO-NE has not explained how the FCA will produce competitive clearing prices when there is no review of new capacity resource offers for competitiveness. Additionally, NEPGA said that the RTO has not determined how it, or the Internal Market Monitor, can testify to the competitiveness of the FCA clearing price without any transparency on new capacity resource offers.

Eliminating the MOPR without "counter-balancing changes" violates the need for wholesale markets to balance consumer and investor interests properly, NEPGA said.

AEE Offers Amendments for Order 2222 Compliance Proposal

ISO-NE's Order 2222 proposal does not meet FERC's directive to enable distributed energy resources (DERs) to offer wholesale market services they are technically capable of providing through aggregation, Jeff Dennis, managing director and general counsel for Advanced Energy Economy, said in a *presentation*.

Without viable participation models for many DERs, New England will forego the option to pursue cost savings, market efficiencies and reliability benefits through wholesale markets, AEE added.

AEE proposed a series of five individual amendments that are not part of an overall package, including allowing submetered load to participate as demand response and submetering by third parties.

Load reductions from a DER allow customers who cannot participate at the customer meter, because of the cost of metering and/or widely variable load, to participate with a dispatchable device behind the meter, AEE said. It said CAISO uses a FERC-approved DR model that allows submetered EV charging equipment to participate as DR under Order 745.

Allowing third-party metering permits aggregators to meter the injection, withdrawal and load reduction of all DERs within each aggregation without requiring reconstitution by meter readers. Third parties bear costs of additional equipment and do reconstitution when required. The arrangement would facilitate DER aggregation deployment sooner and in the areas with no advanced metering infrastructure, AEE said.

The precedent cited by AEE is the NYISO DER participation model that allows third parties to provide metering and meter data services for wholesale market participation. It defines the roles, responsibilities, equipment and data quality standards while describing the processes for data processing and analysis. It also provides checks and balances to ensure data accuracy.

ISO-NE must make its Order 2222 compliance filing by Feb. 2, 2022.

— Jason York

ISO-NE News

EBC Highlights Trends in Maine, Mass. Solar Markets

By Jennifer Delony

Maine and Massachusetts have vastly different installed solar generation capacities, but the two states are dealing with similar market issues as they work to meet their clean energy goals.

The Environmental Business Council of New England gathered industry experts on Thursday to discuss the status of solar in the Northeast, providing a look at key solar market trends playing out in Maine and Massachusetts.

Interconnection

Distributed generation interconnection and grid infrastructure investment, together, are "the single biggest impediment for continued [solar] success in Massachusetts and Maine," Kelly Friend, vice president of policy and regulatory affairs at solar developer Nexamp, said during the webinar.

The two states, which are Nexamp's primary New England markets, are not alone in their struggles to find a good pathway for how DG can quickly and affordably connect to the grid. While interconnection costs can be low in nascent DG markets, Friend said, the costs usually go up over time, depending on prior grid investments.

"We're seeing that in Massachusetts, and particularly in Maine," she said.

Some projects can trigger the need for a grid upgrade on a congested part of the system, which can increase the project's interconnection cost by millions. And it can take a long time to get through an interconnection queue when grid studies hold up the process.

Massachusetts currently has 3,380 MW of installed solar capacity and Maine has 280 MW, according to the Solar Energy Industries Association.

Nexamp operated in Massachusetts for about five years before it began to see interconnection issues there in about 2018, according to Friend. In Maine, she said, it happened much faster. The state's DG program opened in about 2019, and similar issues arose after about a year.

"That's a result of the load profiles of both states and the investments in the grid that the utilities hosting those projects and interconnecting those projects have made," she said.

Figuring out the interconnection conundrum is critical for achieving net-zero goals and signaling developers that they can move forward with business.

"Until we see signs of clear and consistent progress on interconnection, it's very hard for us to think about Massachusetts growing at the rate we want to see it grow and need to see it grow from a climate perspective, because the cost and time to interconnect these projects is just so significant," Friend said.

Nexamp is trying to take the lessons it has learned in Massachusetts and export them to Maine to ensure that projects there aren't triggering huge interconnection costs and experiencing regulatory lag time in five years.

Maine and Massachusetts have open initiatives that are helping the states understand how best to encourage solar development in harmony with the agricultural sector. | *Nexamp*

Regulatory Responses

In Massachusetts, some projects are seeing burdensome interconnection costs, and grid studies have left other projects in the queue for up to three years, according to Eric Steltzer, director of the Renewables and Alternative Energy Division at the Massachusetts Department of Energy Resources (DOER).

The Department of Public Utilities, in response, opened a docket (20-75) last fall to investigate the problems and present options for resolving them.

Regulators issued a straw *proposal* within the docket that incorporates DG planning into distribution system planning. The proposal also outlines a pathway for cost allocation of transmission upgrades that goes through the distribution system owner's capital investments and becomes a fee to all interconnecting facilities that benefit from the upgrade.

DOER supports the straw proposal, and stakeholders are awaiting an order from the DPU in that docket, Steltzer said.

Maine is also trying to resolve its solar project interconnection problems through a Maine

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Public Utilities Commission investigation.

"Earlier this year, when CMP [Central Maine Power] issued some pretty shocking prices related to interconnecting solar projects, the governor sent a letter to the PUC asking them to look into what was going on with CMP's interconnection process," Celina Cunningham, deputy director of the Maine Governor's Energy Office, said during the webinar.

The PUC issued a notice for the formal investigation (2021-00035) in April and held a series of hearings throughout the summer. The proceedings sought clarity on why CMP told some developers with signed interconnection agreements that they would incur significant, unanticipated grid upgrade costs.

PUC staff issued a bench memorandum on Sept. 21 that essentially found CMP did not properly anticipate the effect that a 2019 law (LD 1711) designed to encourage solar development would have the grid. Staff asked for comments on the basis for and potential calculation of penalties. Staff will issue additional recommendations in an examiner's report after reviewing those comments.

In its comments on the memorandum Oct. 12, CMP said that it has revised its estimated upgrade costs and there is no evidence of harm to any solar developers from its actions. The utility also said there is no basis for imposing a penalty.

Solar and Agriculture

Maine and Massachusetts are working on independent initiatives that will help them understand how to incentivize solar development in harmony with the agricultural sector.

Massachusetts proposed changes on Oct. 6 to its dual-use *guidelines* for projects under the Solar Massachusetts Renewable Target (SMART) program, according to Steltzer. Dual-use projects, which site solar on land designated for agricultural practices, receive a 6-cent/kWh adder under the SMART program.

The draft guidelines would, among other things, set a goal of 80 MW for dual-use projects, increase the eligible system size to 5 MW and require new farms to be operational for three years to qualify for the adder, Steltzer said.

DOER is accepting comments on the draft guidelines until Oct. 27.

In Maine, a stakeholder *group* has been studying solar and agricultural lands since June. The Governor's Energy Office is co-chairing the group to look at "how to balance the use of Maine farmland ... and development of solar and putting forward a number of recommendations," Cunningham said.

The group wants to identify and prioritize different types of lands, identify farmland stressors and understand the lifecycle of solar projects on lands that could revert to agriculture.

A report is due in December, and the group's next meeting is on Oct. 21. ■

MISO News

MISO Tx Expansion Plan Proceeds to Board Vote

By Amanda Durish Cook

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MISO's Planning Advisory Committee has voted to advance the 2021 MISO Transmission Expansion Plan (MTEP 21) to the RTO's directors.

The committee's sectors voted by email through late September. Seven of the 10 sectors voted in support of the transmission package, with the End-Use, Public Consumers and State Regulatory sectors abstained.

The Board of Directors' System Planning Committee will consider MTEP 21 during an Oct. 25 teleconference before it goes before the full board on Dec. 9.

MTEP 21 includes 339 new projects worth $3.04 billion, a drop from 367 projects totaling almost $3.25 reported by MISO during its September Board Week. This year's package is also significantly smaller than MTEP 20's final $4.05 billion spend on 493 projects.

Broken down, substation work accounts for 38% of MTEP 21's investment, line upgrades take a 36% share, and new lines account for 14%. Remaining costs are spread over transformer work, voltage devices and miscellaneous investments.

"This is very typical for the last couple of cycles," project manager Sandy Boegeman said.

The package's most expensive project is an $86-million rebuild of a line in southern Louisiana rated at just 115 kV. The second most expensive is a $71-million new 161-kV line and breaker stations in southern Iowa. Both projects are needed for reliability reasons.

The next eight most expensive projects range from $43 million to $33 million.

Energy consultant Kavita Maini noted that members have an incomplete picture of total MTEP spending because MISO is waiting until early next year to propose higher-voltage, long-range transmission projects that will be added after the fact. (See *MISO Targets March Approval for Long-term Tx Projects*.)

However, some stakeholders, primarily those from MISO South, have been casting doubt on the need for billions of dollars in long-term transmission projects. (See *Tensions Boil over MISO South Attitudes on Long-range Transmission Planning*.)

"Right now, we don't know the MTEP 2021 total cost," Maini said.

Boegeman said MISO will post an addendum to the MTEP 2021 report when long-range projects are finalized by next March.

Scott Goodwin, an expansion planning engineer, said with MTEP 21 winding down, MISO planners have shifted focus to MTEP 22.

During a Planning Subcommittee teleconference Oct. 12, Goodwin said MISO's expansion planners have already completed an initial review of transmission owners' MTEP 22 project proposals. MISO will begin holding subregional planning meetings for the portfolio's projects in January. ■

MISO News

MISO Hopes Bifurcated MVP Cost Allocation Will be Temporary

RTO Still Hunting the Cost Allocation 'Unicorn'

By Rich Heidorn Jr. and Amanda Durish Cook

MISO officials said Thursday that the RTO's proposal to conduct its Multi-Value Project (MVP) cost allocation separately for its South and Midwest regions is likely to be in place for three to four years.

Chief Operating Officer Clair Moeller told the Regional Expansion Criteria and Benefits Working Group (RECBWG) that MISO will propose a bifurcated MVP cost allocation because of the limited transfer capability between the subregions and the RTO's failure to capture what he called the "unicorn" of a more granular cost allocation.

The RTO announced the plan last month. (See *Tensions Boil over MISO South Attitudes on Long-range Transmission Planning*.)

MISO plans to file the proposal with FERC by the end of November. Officials promised to post tariff redline language by the end of next week and allow at least a week for stakeholder feedback.

Moeller said he hopes the separation of the zones will be temporary, saying it could change as a result of upgrades to relieve the transmission bottleneck or new rules resulting from FERC's Advanced Notice of Proposed Rulemaking on transmission planning and cost allocation. (See related story, *FERC Tx Inquiry: Consensus on Need for Change, Discord Over Solutions*.) And he said officials would "continue hunting for the unicorn."

The COO also said the bifurcated MVP recognizes the limited transfer capability between the subregions to ensure a "roughly commensurate, beneficiaries-pays cost allocation."

Within five years after implementing the change, MISO will evaluate the transmission investments approved across the subregions and whether the cost allocation results in an equitable outcome for customers "across the entire footprint," Moeller said.

He challenged the "myth" that previous MVPs built in the Midwest have provided "enormous benefits for the southern region."

Since 2019, Moeller said, the flow through the Midwest-South interface has been "reciprocal." For 2021, there has been slightly more flow from the South to the Midwest (52%) than vice versa. About 2% of the intervals found Midwest-South flow at the maximum capacity of 3,000 MW, while 8% of the intervals showed South-Midwest flows at the limit.

Wisconsin Public Service Commissioner Tyler Huebner asked why MISO couldn't use a metric such as adjusted production costs (APC) for more granular allocations.

Moeller said the northern two-thirds of MISO has "pretty uniform" goals for fleet changes, driven by load. If Michigan benefits from a project in Northern Indiana, MISO must ensure "that costs from Northern Indiana get charged to Michigan."

"Making sure that the drivers and the payers match is harder to do when you get more granular," he said.

David Sapper, representing the MISO LSE Coalition, asked about the potential impact of the Southeast Energy Exchange Market (SEEM). The market's members, including Southern Co., Dominion Energy South Carolina, the Tennessee Valley Authority and Duke Energy, proposed improving bilateral trading in the region through automation and a move from hourly to 15-minute transactions. The SEEM agreement took effect Oct. 11 after FERC deadlocked 2-2 on the proposal. (See related story, *SEEM to Move Ahead, Minus FERC Approval*.)

"We're not sure the Southeast [market] is going to have a big effect," Moeller responded, saying MISO's efforts to develop more transfer capacity with Southern and TVA failed to gain "traction."

"They're kind of busy doing their own thing right now," he said. He predicted the SEEM members will see "seams friction" as they proceed. "We hope that that brings to the table" to discuss stronger interconnections, he said.

Steve Leovy of WPPI Energy expressed frustration with MISO's approach, saying a unicorn "is not an appropriate metaphor" for the RTO's challenges. "I've never seen a unicorn, but I have seen cost allocations that are more granular than 100% postage stamp," he said.

He said improving transfer capability on the system could reduce required reserve margins in MISO zones. That "has a real economic value that we could measure if we try," he said.

Lauren Azar, representing the Sustainable FERC Project, said she agreed with Leovy that stakeholders can develop a cost allocation that reflects the goals of the long-range transmission plan to ensure reliability and reduce congestion costs. "But that's going to take time, creativity and a good-faith effort by all stakeholders," she said.

Louisiana Hostile to Tx Expansion

The task force *voted* 32-29 last month against using a cost allocation proposed by Entergy and its state regulators that would set a higher bar for projects to be cost allocated and assign more specific beneficiaries. Multiple MISO stakeholders have accused Entergy of stalling transmission solutions that could bring outside supply into its territory. (See *MISO Stakeholders Blame Entergy for Long-range Transmission Impasse*.)

The Louisiana Public Service Commission, which has been clear that it doesn't want to share in the costs of transmission projects built in the Midwest, will receive a presentation at its Oct. 20 *meeting* on a staff report looking at the pros and cons of MISO membership.

The PSC said it will pay "particular attention to the need for the state to remove itself from MISO membership prior to 2022 to avoid a negative offset of benefits to ratepayers."

The Louisiana commission's move follows an audit from the Mississippi Public Service Commission that questions the continued benefits of MISO membership in light of the long-range transmission plan, a move to a four-season capacity market and an increase of the RTO's value of lost load. (See *Mississippi PSC Audit Questions MISO Membership*.)

Election

Meanwhile, the RECBWG will be accepting nominations for chair and vice chair for 2022 at *StakeholderRelations@MISOenergy.org* until Oct. 21.

Group Chair and Michigan Public Service Commissioner Dan Scripps said both he and Vice Chair Carolyn Wetterlin, of Xcel Energy, plan to seek re-election. If there are more than one candidate for either position, there will be an election by email ballot. ■

NYISO News

NYISO Exploring Dynamic Reserves

By Michael Kuser

NYISO is evaluating the feasibility of dynamically scheduling reserves, a project that involves determining the minimum operating reserve requirements based on the single largest source contingency during market runs and exploring the dynamic allocation of reserves based on available transmission capability.

The ISO is currently stress-testing the prototype mathematical formulation in the day-ahead security-constrained unit commitment, real-time commitment and real-time dispatch intervals, Pallavi Jain, NYISO energy market design specialist, in *presenting* an update on the Reserve Enhancements for Constrained Areas project to stakeholders.

"Essentially, we're adding additional constraints to the optimization to see if we can schedule reserves dynamically," Jain said. "Right now, because we're doing day-ahead — and in day-ahead you barely ever see any shortages — we're looking at the clearing prices to see if it's being determined correctly, if the right resources are being backed down how we would expect it."

NYISO is testing the prototype under different scenarios and analyzing the accuracy of the results to test the effectiveness of incorporating it into the market software. The ISO has always operated under static reserve requirements, so moving to a dynamic procurement methodology required studying, Jain said.

The study is also looking at the dynamic allocation of reserves based on available transmission capability; in other words, shifting reserve procurements to lower-cost regions when sufficient transmission capability exists.

"Therefore, a more dynamic reserve procurement methodology could address these two considerations and also improve market efficiency by better aligning market outcomes with how the power system is operated," Jain said.

The transmission part of the study includes creating locational operating reserve requirements for certain load pockets within New York City and perhaps modeling those requirements based on available transmission capability. The study also will evaluate modeling of certain city load pockets when operating reserves provide congestion relief.

"NYISO believes an efficient, more granular operating reserves concept is dependent on developing the transmission as reserves capabilities," Jain said.

The ISO expects to implement dynamic reserves in 2025.

"This is a very big change in how we currently model reserves," Jain said. ■

Current Operating Reserve Requirements

- Currently, the NYISO procures fixed quantities of operating reserves in specified regions across the state.*

	NYCA	EAST	SENY	NYC	LI
10 Minute Spinning Reserve	½ A = 655 MW	¼ A = 330 MW	0 MW	0 MW	0 MW
10 Minute Total Reserve	A = 1,310 MW	1,200 MW	0 MW	500 MW	120 MW
30 Minute Reserve	2 A = 2,620 MW	1,200 MW	1,300–1,800 MW	1,000 MW	270-540 MW

A = Most severe NYCA Operating Capability Loss (1310 MW)

| NYISO

NYISO News

NYISO Business Issues Committee Briefs

Constraint Specific Tx Shortage Pricing

The NYISO Business Issues Committee on Wednesday recommended that the Management Committee approve tariff *revisions* related to implementing a revised approach to the current transmission constraint pricing logic.

The proposal includes establishing a revised six-step transmission shortage pricing mechanism for facilities currently assigned a non-zero constraint reliability margin (CRM) value, said Kanchan Upadhyay, energy market design specialist.

Each step corresponds to a specified percentage of the applicable CRM value, and the final step will price all shortages in excess of the applicable CRM value, thereby facilitating the ability to eliminate reliance on constraint relaxation for such facilities.

Given the expanded scope of graduated transmission demand curves envisioned by the Constraint Specific Transmission Shortage Pricing proposal, the ISO is working to implement the proposal in tandem with its Lines in Series effort, which seeks to develop enhancements to the measures used for addressing the limitations arising out of the operation of graduated transmission demand curve mechanisms.

The proposal will also apply a non-zero CRM value (e.g., 5 MW) to internal facilities currently assigned a zero value CRM, with a separate two-step transmission demand curve mechanism for such facilities.

The first step is valued at $100/MWh and will price transmission shortages up to the proposed CRM value. The second step is valued at $250/MWh and will price all shortages in excess of the proposed CRM value, thereby facilitating the ability to eliminate reliance on constraint relaxation for such facilities, Upadhyay said.

The proposal will maintain the current single value $4,000/MWh shadow price capping method for external interface facilities (zero value CRM), permitting the continued use of constraint relaxation for external interfaces, she said.

One stakeholder wanted assurance that the Lines in Series initiative would in no way delay implementation of the transmission shortage pricing proposal.

"The constraint specific transmission pricing should be implemented as proposed today with Lines in Series," said Michael DeSocio, NYISO director of market design. "Both will be implemented together in 2023, and we will be working with stakeholders to illuminate our thoughts on how to solve the Lines in Series effort later this year."

CSR-related Tariff Revisions

The BIC also approved tariff *revisions* related to implementation of co-located energy storage resources (CSR) injection and withdrawal scheduling limit constraints and CSR-generator specific operating parameters.

FERC in March accepted NYISO rules allowing an energy storage resource to participate in the wholesale markets as a CSR with wind or solar, and the ISO has since been working on the market software. (See *FERC Approves NYISO Co-located Storage Model*.)

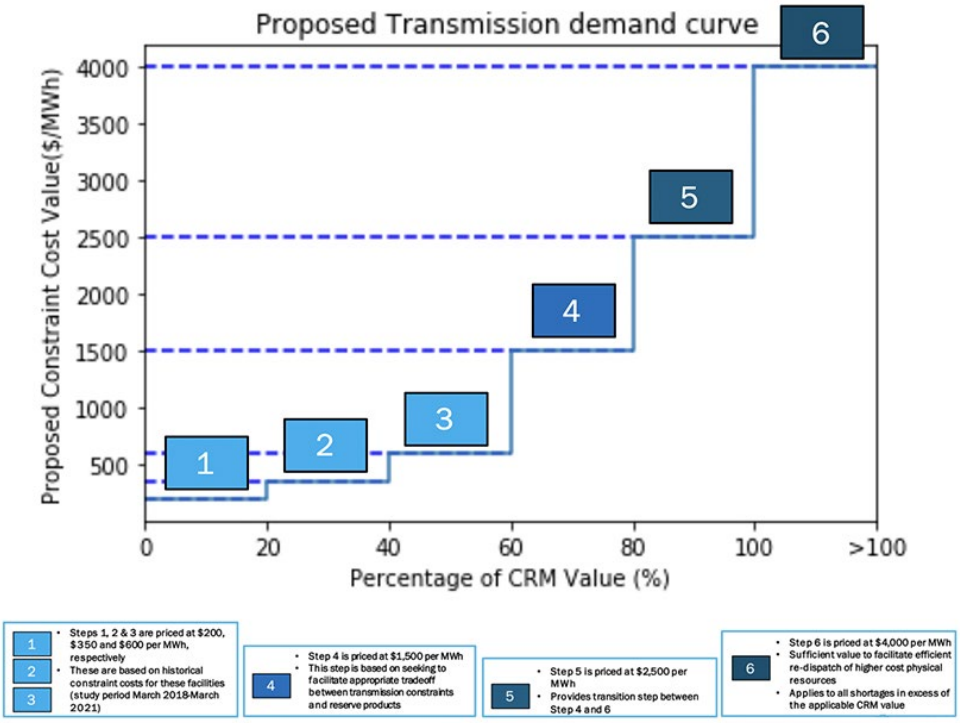
"In solving the market software, we found there were unique circumstances where these constraints were actually competing with other constraints in the model, specifically operating parameters of the generator specific to the CSR model," said Zachary Stines, manager of energy market design.

In that situation the ISO had to prioritize which constraint was going to be respected and which was going to be relaxed to come up with an appropriate solution, "so this is really to prevent an issue where you could have these competing constraints on the individual units and then also this withdrawal or injection limit constraint," Stines said.

Language will be added to the applicable manuals (likely the Day-Ahead Scheduling Manual and the Transmission and Dispatch Operations Manual) describing how the scheduling limits will interact with unit specific constraints, such as ramp, upper operating limit and lower operating limit.

If approved by the Management Committee this month and the Board of Directors in November, NYISO will make a filing with FERC and request a flexible effective date for the tariff changes that is prior to year-end. ■

— Michael Kuser



Proposal for non-zero constraint reliability margin (CRM) value facilities | *NYISO*

PJM News

Akin Gump Public Policy Team Helped Win Ohio Nuke Bailout

New Court Filings Reveal Knowledge of 'Dark Money' Group

By John Funk

In affidavits *filed in a federal bankruptcy court* Oct 12, four employees of the national law and lobbying firm Akin Gump Strauss Hauer & Feld denied wrongdoing but revealed the firm's deep involvement in FirstEnergy's efforts to win passage of nuclear bailout legislation in the Ohio legislature.

That passage led to the indictment on federal racketeering bribery charges of the former speaker of the Ohio House of Representatives and four of his associates and the company paying a $230 million fine in a deferred prosecution deal. (See *DOJ Orders $230 Million Fine for FirstEnergy*.)

Akin has represented FirstEnergy since its incorporation in 1997, as well as its generation subsidiary FirstEnergy Solutions in its bankruptcy case, which began March 31, 2018.

After Akin last year revealed in a routine disclosure of charges and expenses — including those for assisting the company to win approval of Ohio House Bill 6 and fighting the resulting campaign against a ballot drive to rescind it — U.S. Bankruptcy Court for the Northern District of Ohio Judge Alan Koschik held up the final payment of the firm's $67 million in legal fees while waiting for a Justice Department investigation into the passage of H.B. 6 to conclude.

But the judge demanded specific information from four employees, including their knowledge of FirstEnergy giving millions of dollars to Generation Now, a 501(c)4, the company used as a "dark money" organization to fund a legislative and public relations campaign. Classified as social welfare organizations by the IRS, 501(c)4 groups do not have to report donors.

After a second delay in July, the judge set a deadline for this week. The sworn disclosures of three Akin partners and a senior policy adviser give detailed accounts of their involvement with the company and top Ohio-based lobbyists in 2018 and 2019 to assist former Ohio House Speaker Larry Householder (R)

Davis-Besse nuclear plant in northern Ohio | *NRC*

PJM News

engineer the passage of the bailout legislation.

H.B. 6, which has since been rescinded, created a six-year, $1.1 billion public bailout of two Ohio nuclear plants, formerly owned by the company. Its passage also immediately led to the Justice Department investigation and subsequent indictments.

Householder has pleaded not guilty to federal racketeering charges stemming from that multiyear campaign and is awaiting trial.

Two of his associates, including lobbyist Juan Cespedes and political strategist Jeffrey Longstreth, also pleaded guilty but have not been sentenced as the Justice Department investigation continues. Longstreth also pleaded guilty on behalf of Generation Now.

Affidavits Describe Company Activities

The affidavits of the Akin employees offer numerous details about their efforts, which included daily consultations to win passage of the bailout, beginning a year before the legislation won approval.

"I was first introduced to Juan Cespedes and his company, the Oxley Group, in or around March 2018," *wrote* attorney Jamie Tucker, an Akin partner and member of the firm's Law and Policy section. "At the time, we were looking for in-state legislative consultants to help with outreach to policymakers regarding the nuclear power plant deactivation process in Ohio and announcement of FES' bankruptcy, as well as to assess the likelihood of possible legislative solutions."

The affidavit continues that Cespedes "became the principal day-to-day point of contact" and that Akin and FES "relied upon Cespedes to report on the likelihood that particular members of the legislature would be supportive."

A year later, leading up to the votes in the House and Senate, Tucker described his role and that of other members of the Akin team as one of analysis and strategizing.

The court also wanted to know specifically whether:

- Akin's staffers were aware of Generation Now before FES emerged from bankruptcy in February 2020;
- they had advised FES "with respect to interaction with Generation Now"; and
- they had advised FES regarding a "$1,879,457 electronic transfer to Generation Now on July 5, 2019 … or regarding any other transfer to or for the benefit of Generation Now."

Tucker responded that in summer 2018, he learned that Generation Now "was a 501(c)(4) organization addressing energy independence and economic development, and that it was aligned with Larry Householder."

"Over the course of the next two months, FES' governmental affairs team and I, with input from outside consultants and others at Akin Gump, advised FES in connection with its decision to donate a total of $500,000 to Generation Now in October 2018 as part of its broader, bipartisan contribution strategy," Tucker wrote.

He added that he had no "personal knowledge" of the $1.87 million transfer "or any other transfers" other than the $500,000 that had been discussed.

In a *letter* accompanying the affidavits, Akin attorney Abid Qureshi, who argued the FES case on several occasions during hearings in bankruptcy court, told the court that "the firm is not aware of any evidence that its attorneys and professionals knew of any illegal activity" and that "Akin Gump is not aware of anything that would lead the firm to revise its pending fee application."

He said Akin's restructuring lawyers routinely attended FES board meetings during the Chapter 11 proceedings, including a May 28, 2019, meeting.

"During that meeting, the board adopted a resolution, which Akin Gump corporate attorneys had drafted, authorizing expenditures of up to $15 million to Generation Now to fund Generation Now's voter-education efforts," Qureshi wrote.

He added that the "policy professionals," such as Tucker, "were not specifically aware of the $15 million … and they did not advise on the authorization. Some of them were aware that FES' media and voter-education efforts in support of House Bill 6 had been transitioned from another firm to Generation Now and that monies were being spent on those efforts."

Qureshi's letter went on to describe an August 2019 FES board meeting when the board adopted another resolution drawn up by the firm authorizing additional expenditures of up to $25 million in a drive to defeat a referendum petition that had been organized by opponents of H.B. 6. Again, he stressed that Akin's team working with FES on the ground were not aware of those voted-upon decisions.

The court has set a final hearing on the issue of the final payments to Akin for Oct. 26. ■

PJM News

PJM MRC/MC Preview

Below is a summary of the issues scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings on Wednesday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

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

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Stakeholders will be asked to *endorse* the 2021 reserve requirement study (RRS) *results* for the installed reserve margin (IRM) and the forecast pool requirement (FPR). The study was unanimously endorsed at the Oct. 5 Planning Committee meeting. (See "Reserve Requirement Study Endorsed," *PJM PC/TEAC Briefs: Oct. 5, 2021*.)

C. The committee will be asked to *endorse* proposed updates addressing behind-the-meter generation (BTMG) business rules on status changes and corresponding revisions to *Manual 14D*, *Manual 14G* and the *tariff*. The updates were developed in special sessions of the Market Implementation Committee. (See "Manual 14G Updates Endorsed," *PJM PC/TEAC Briefs: Aug. 31, 2021* and "Manual 14D Endorsed," *PJM Operating Committee Briefs: Sept. 10, 2021*.)

D. Members will be asked to *endorse* proposed revisions to *Manual 15: Cost Development Guidelines*, the *Operating Agreement* and the *tariff* to address incremental and no-load energy offers. The Cost Development Subcommittee proposed revising the no-load cost and incremental energy offer definitions to clearly define what costs can be included, including operating costs, tax credits and emissions allowances. (See "Manual 15 Revisions Endorsed," *PJM MIC Briefs: Sept. 9, 2021*.)

E. Stakeholders will be asked to *endorse* the proposed solution and *manual* revisions to address the calculation of the energy efficiency add-back in Reliability Pricing Model auctions. The proposal, which called for modified language to section 2.4.5 of Manual 18 to reflect revisions to the EE add-back method, was endorsed at the Oct. 6 MIC meeting. (See "Energy Efficiency Add-back Endorsed," *PJM MIC Briefs: Oct. 6, 2021*.)

Endorsements (9:10-10:55)

1. Resource Adequacy Senior Task Force Charter (9:10-9:35)

The committee will be asked to *approve* the proposed *charter* to create a new senior task force to discuss topics related to resource adequacy listed in an April 6 *letter* from the Board of Managers and to recommend possible changes to the capacity market. (See "Resource Adequacy Charter," *PJM MRC Briefs: Sept. 29, 2021*.)

3. Undefined Regulation Mileage Ratio Calculation (9:35-10)

Members will be asked to *endorse* PJM's proposal to change the undefined regulation mileage ratio calculation in *Manual 28* and the *tariff*. The proposal will also be voted on at the MC meeting on the same day. If the proposals fails, stakeholders will be asked to vote on a separate *proposal* from the Independent Market Monitor. (See "Regulation Mileage Ratio Calculation Endorsed," *PJM MIC Briefs: Sept. 9, 2021*.)

4. ARR/FTR Market Task Force Update (10-10:35)

Stakeholders will be asked to *endorse* a joint PJM-stakeholder proposal with corresponding *manual* and tariff *revisions* to address the RTO's auction revenue rights and financial transmission rights. The proposal was endorsed at the October MIC meeting. (See "ARR/FTR Market Task Force Proposal," *PJM MIC Briefs: Oct. 6, 2021*.)

5. Max Emergency Revisions (10:35-10:55)

The committee will be asked to *endorse* proposed revisions to *Manual 13: Emergency Operations* addressing the maximum emergency category. Stakeholders are being asked to endorse the revisions upon first read.

Members Committee

Endorsements (1:45-2:55)

1. Initial Margining Solution (1:45-2:15)

Stakeholders will be asked to *endorse* proposed tariff *revisions* on rules related to initial margining that close out the work of the Financial Risk Mitigation Senior Task Force (FRMSTF). A joint proposal from Perast Capital and Duke Energy was endorsed at the September MRC meeting after hours of debate. (See *PJM Stakeholders Endorse Initial Margining Proposal*.)

3. Manual 34 Revisions (2:35-2:55)

The committee will be asked to *approve* proposed revisions to Manual 34: PJM Stakeholder Process addressing the inclusion of forums as a stakeholder body. The revisions were originally discussed at the Stakeholder Process Forum and presented for a first read at the September MC meeting. (See "Manual 34 Revisions," *PJM MRC/MC Briefs: Sept. 29, 2021*.) ■

— Michael Yoder

SPP News

SPP Markets and Operations Policy Committee Briefs

Staff, Members Call for More Coordination with Gas Industry

SPP staff told stakeholders last week they are searching for ways to urge change in the energy industries following February's disastrous winter storm, when natural gas curtailments led to the RTO's first rolling outages in its 75-year history.

Several members urged the grid operator to focus on the gas curtailments they said were the root cause of the generation outages during the storm, an opinion shared by FERC and NERC in the draft report of the joint inquiry into the storm and its impacts. (See *FERC, NERC Share Findings on February Winter Storm*.)

Bill Grant, SPS | © *RTO Insider LLC*

"You can argue all day long whether the curtailments started happening before the outages started. … Seventy percent of firm gas was curtailed. That to me is the root cause," Southwestern Public Service's (SPS) Bill Grant said during the Oct. 11-12 Markets and Operations Policy Committee meeting.

"I know we need to look at all this other stuff, but we should do so without being told. That's common practice," he said. "The main focus should be on [gas-electric] coordination and domestic [gas] contracts."

Mike Wise, whose Golden Spread Electric Cooperative sits in West Texas along with SPS, said most of the co-op's problems occurred because of ERCOT's problems. The Texas grid operator lost more than half of its thermal generation because of curtailments and freeze-offs of natural gas facilities, which led to ripple effects elsewhere.

"The real issue is electric reliability in ERCOT is impacting others besides ERCOT," Wise said. "We have firm transportation arrangements with our pipeline providers. They said they were available and ready to go. It was the fuel-processing plants on interruptible rates and fuel suppliers that were on ERCOT outages [that failed]. It was the other pieces of the gas infrastructure feeding into [the pipelines] that forced them to declare *force majeure*. We need to complete that analysis."

"Duly noted," SPP COO Lanny Nickell said. "We did notice there was some increase in generation outages due to fuel issues before we had to shed load. We can sure dig into that information."

The RTO in July released a comprehensive *report* on its response to the storm's effects that said a lack of fuel supplies led to generation's unavailability and was "the largest contributing factor to the severity of the winter weather event's impacts … exacerbated by record wintertime energy consumption and a rapid reduction of energy imports." (See "Grid Operator Releases Report on Performance During Winter Storm," *SPP Board of Directors/Members Committee Briefs: July 26-27*.)

Among the report's 22 recommendations are two aimed at improving fuel assurance: evaluate and, if necessary, advocate for improvements in gas industry polices to assure supplies are "readily and affordably" available during extreme events; and developing policies to improve gas-electric coordination to improve emergency response.

"There's not a lot we can do about it but talk about it and advocate as best we can," Nickell said. "We can make sure our facilities are hardened and do everything we can, but if the gas doesn't show up, there's nothing we can do about that."

"If you would have asked everybody in January if they felt like they were ready for the winter, everybody would have said, 'Yes, we feel good,'" Grant said. "But even when you're in good communications with the suppliers, you can't stop them from declaring *force majeure*. You could still have 70% curtailments on firm gas deliveries … and we can't do a thing about it."

SPP in August followed up on the report by surveying its generator owners and operators to learn about their plans for having available fuel supplies for the upcoming winter. The survey generated 60 responses, reflecting 85% of the RTO's nameplate capacity and including 52 spreadsheets with unit-specific information. It revealed that 68% of the respondents already have plans and process in place.

The survey's data will only be used for planning purposes and itself does not have any compliance implications, Nickell said.

SPP News

"It feels to me we're going to be in better shape this upcoming winter than we were last winter," he said. "If the upcoming winter is worse than the last one, that may be a moot point. That's about all we can do with the information we have right now."

Nickell said the newly constituted *Improved Resource Availability Task Force* will have an opportunity to weigh in. The task force, under the Regional State Committee, has already met four times in tackling the Tier 1 recommendations from the winter-storm review related to fuel assurance and resource planning and availability.

The group is chaired by Arkansas Public Service Commission Chair Ted Thomas, with Golden Spread's Natasha Henderson as vice chair. They are joined by five regulatory commissioners and staff and five member representatives. The conference calls have drawn more than 70 dial-ins each time, Nickell said.

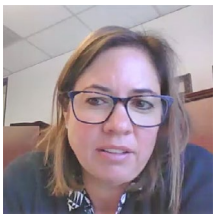
"What we've done gives us a head start with the FERC-NERC recommendations," he said.

Midwest Energy's Bill Dowling noted that FERC lacks the jurisdiction to impose reliability standards on its own and said that work should reside with the *North American Energy Standards Board* (NAESB), which has jurisdiction over both the gas and electricity industries.

"They've been in a slumber for decades on these types of issues. That needs to be addressed," Dowling said.

Michael Desselle, SPP's chief compliance and administrative officer and a member of the NAESB board, advised the MOPC to "stay tuned."

"We will put in a standards request, and [NAESB] won't have the option not to do anything," he said. "If they choose to, they will be on the record for not doing anything."



Denise Buffington, Evergy | *SPP*

MOPC Chair Denise Buffington, of Evergy, said an education session on NAESB would be scheduled for the committee's next meeting.

"We need to be cautious about getting into the gas business," she said. "We need a little more research on the lines of jurisdiction between what FERC does and what NAESB does."

MOPC Approves SCRIPT Report

The MOPC endorsed the Strategic and Creative Re-engineering of Integrated Planning Team's (SCRIPT) *report*, but only after declining to endorse the team's 46 recommendations over questions of project oversight and demand on staff. Members approved the endorsement motion with 97% approval.

The Board of Directors formed the SCRIPT last year and directed it to recommend broad changes to the RTO's transmission planning processes that would better meet customer needs and resolve concerns about transmission investment amid rapid industry changes. The team came up with 35 recommendations and 11 sub-recommendations for business practices, policies and tariff revisions to consolidate planning processes, improve services processes, optimize SPP's transmission network, improve decision quality, facilitate beneficial interregional energy transfers and improve cost sharing.

"There's a lot of recommendations built into the report," said Grant, the lone member to vote against the motion during the MOPC meeting and Wednesday's Strategic Planning Committee call. "Some of them are good to implement, but if I endorse the recommendations, then it will be misinterpreted that I support those recommendations. There are a couple we don't support and will not support. That being said, I think there's a lot of good work and a lot of good work that needs to happen."

"I still have concerns about resources on both sides. I don't hear these are mandates," Oklahoma Gas and Electric's Usha Turner said. She noted staff and members will have their hands full responding to FERC's Advanced Notice of Proposed Rulemaking on transmission planning and cost allocation (*RM21-17*), the winter weather report and implementing SPP's new strategic plan.

"What do we reshuffle? What do we throw out?" Turner asked.

"The proof in the pudding will be what we get out of the end with cost allocation," American Electric Power's Richard Ross said.

Nickell said he will work with Directors Mark Crisson, who also chairs the SCRIPT, and Bronwen Bastone to coordinate the work going forward. The board could designate an existing stakeholder group or commission a new one to oversee the team's implementation.

Central to the SCRIPT's work are the overarching consolidation policy recommendations. During a MOPC education session last month, Nickell told members that that the new consolidated transmission planning process will save $3 million to $4 million annually in administrative cost savings once it is in place. SPP currently incurs about $28.5 million in annual costs for its planning processes. (See *SPP: Consolidating Tx Planning Could Yield Big Savings*.)

Staff said the improved processes should also lead to more optimal transmission, equitable cost-sharing, timely outcomes, increased certainty and greater transmission value.

The board will consider the recommendations during next week's meeting. If approved, staff and stakeholder groups will either perform additional assessments to determine future action or work to implement policy direction through further design and process development.

"This will require some group, somewhere," Crisson told the SPC on Wednesday. "The industry environment is rapidly changing around us, and we need to be able to respond to that."

"These are good concepts. If we don't get started, we're not going to finish," board Chair Larry Altenbaumer said. "No one should view that everything else is grinding to a halt and we're moving forward full barrel. The challenge of leadership is with the board."

SPP Asks for Z2 Rehearing

Paul Suskie, SPP | *SPP*

General Counsel Paul Suskie told the committee that a recent *U.S. appeals court decision* denying petitions by SPP and OG&E to review a FERC order on transmission upgrade costs lays out a clear path forward in finally resolving Attachment Z2's never-ending saga.

The D.C. Circuit Court of Appeals ruled in August that FERC was correct in reversing a retroactive waiver it had granted SPP over collecting transmission upgrade costs under the tariff's Attachment Z2 (20-1062). The commission had granted the waiver so that it could invoice transmission service customers for Z2 credit payment obligations for 2008-2016 (ER16-1341) but reversed course in 2019. FERC said its original decision was prohibited by the filed-rate doctrine and the rule against retroactive ratemaking. (See *DC Circuit Upholds FERC Ruling on SPP Z2 Saga*.)

"The ruling helps define the future of Z2," Suskie said.

SPP News

SPP and OG&E on Oct. 12 filed a joint *request* with the D.C. Circuit for an *en banc* rehearing, with a decision expected between November and February. If the request is denied and there are no further appeals, the RTO expects to receive a refund order from FERC for $138.5 million in credit payment obligations.

Suskie said SPP would then have to resettle Z2 credit obligations from September 2015 on, amounting to about $371 million.

SPP has a compliance filing pending at FERC, where five other dockets involve litigation over the Z2 process, filed by OG&E (EL19-77), EDF Renewables (EL19-75), Western Farmers Electric Cooperative, (EL19-93), Cimarron Windpower (EL10-96) and Kansas Electric Power Cooperative (EL17-21).

The grid operator expects to make additional filings at FERC clarifying how it will handle the refunds. "Much, much more to come in the future," Suskie said.

"I would like to say I'm looking forward to it," said Chair Buffington, who led a Z2 task force several years ago. "I'll bite my tongue because I know how complicated it is."

ITP Mitigation Plan Successful

SPP's mitigation plan to get the 2021 Integrated Transmission Planning (ITP) study back on track has been a success, chopping 40 days off the delayed scheduled, staff told members.

The study was to be shared with the MOPC and board in October but will now be presented in January. The 2021 ITP report will be posted in mid-December.

The mitigation activities, approved by both governance groups in July, include waiving requirements to build and assess power-flow models during the 2021 reliability needs assessment; modifying the 2021 scope to allow schedule adjustments within the study; and extending the 20-year assessment's due date to 2023. (See "Tx Planning Mitigation Gets OK," *SPP Markets and Operations Policy Committee Briefs: July 12-13, 2021*.)

"The 20-year assessment is on pause. It's very important to SPP, but it will be unpaused after we focus on the 2021 ITP," SPP's Casey Cathey said.

Staff will eventually be diverted back to the 20-year assessment as they continue to grapple with three studies at the same time.

Annual VRL Analysis Approved

The committee approved the Market Working Group's recommendation to approve the 2020-2021 annual violation relaxation limits (VRLs) analysis. Staff are not proposing any changes to the VRLs, saying the analysis showed no operating constraint sensitivity that reduced both the cost and the number of breaches and that the current VRL blocks provide a proper balance between economics and reliability.

AEP's Ross, who chairs the MWG, suggesting adding language that a Market Monitoring Unit revision request (*RR414*) pursue possible VRL adjustments for extreme weather events and that it "come to fruition" before making additional changes. Ross agreed to pull his language after additional discussion, saying he was sensitive to concerns about additional studies being necessary "before we start monkeying around with the VRLs."

The annual VRL analysis passed with 92% overall approval.

Members also approved the Supply Adequacy Working Group's proposed *RR462* that implements a process that includes a methodology for prioritizing and allocating the available effective load-carrying capability for standalone energy storage resources (ESRs) that qualify as capacity in the SPP balancing authority. The accreditation policy would be the first implemented by SPP for ESRs.

GOTF Nears its Sunset

Members approved four recommendations from the Generator Outage Task Force (GOTF) addressing outage-scheduling practices and concerns over how to reliably schedule outages.

Eliminating model builds and assessments has helped SPP reduce the ITP 2021's delayed schedule. | *SPP*

SPP News

Pointing to the changing resource mix's effect on performing maintenance on conventional resources, staff secretary Kathryn Dial said the task force recommended revising the generation assessment process (GAP), used to help ensure balancing authority capacity adequacy in scheduling outages, be changed from a short-term GAP to generate hourly maintenance margin values.

The GOTF's recommendations also include revising outage-coordination methodology by changing the outage/derate reporting threshold from 25 MW to 10 MW; allowing forced outages to have up to seven days of maximum lead time to align with NERC's generating availability data system; and updating the cause codes.

The committee also endorsed the group's request to be sunset, a move that thrilled Ross. Always eager to see the number of stakeholder groups reduced, Ross said he would send a gold star to Dial, who promised to have it framed.

The task force was created after SPP declared a Level 1 energy emergency alert and called for conservative operations 10 times in 2019. The grid operator attributed six of the 10 operations events to generation outages.

Tariff Updated with Admin Fee's Cap

CFO Tom Dunn had the line of the meeting as he sought to explain a revision request (*RR463*) on the consent agenda that updates tariff language in Schedule 1-A to reflect the recently approved increase to the cap on recoverable costs. The Members Committee and board approved the change from 43 cents/MWh to 46.5 cents/MWh in July, but members wanted to ensure SPP wouldn't take advantage of the increase. (See "Admin Fee Cap Bumped 8.1%," *SPP Board of Directors/Members Committee Briefs: July 26-27*.)

Dunn said the cap's increase does not mean an increase to SPP's costs but is a "look out into the future." He said staff believe the cap is "valid into 2026."

"The tariff language change … doesn't mean we'll hit the number every year. Will you do everything you can to keep it low?" Chair Buffington asked.

"Tom's life is easier when members are happy with the rate," Dunn said.

And Dunn's life did indeed get easier when the committee placed RR463 back on the consent agenda.

RCAR Hybrid Approach OK'd

RR463 was one of four items MOPC members pulled off the consent agenda for further discussion, eventually returning three to the agenda. *RR461*, which proposes a new hybrid approach for the regional cost allocation review (RCAR), was voted on separately and passed with 94% overall approval. The consent agenda passed with 97% approval.

The Regional Allocation Review Task Force recommends using real market data for facilities that have been in service for more than two years and a more theoretical, study-based approach for those approved projects that are still under construction or have not been in service for at least two years, effective with the 2022 RCAR.

The consent agenda included:

- *RR456*: clarifies that ESRs co-located or integrated with generating resources may register as a single resource and can use the market storage resource (MSR) model if desired.
- *RR453*: adds language to clarify which rounds or stages electrically equivalent settlement locations can be nominated during the auction revenue rights allocation process.
- *RR459*: updates the tariff to replace a reference to MSRs' loss factor with ERSes' loss factor.
- *RR475*: corrects the production version of the Integrated Marketplace's protocols to remove market participants' financial harm from an incorrect calculation because of overlapping revision requests.
- *RR460*: updates the minimum transmission design standards for competitive upgrades.
- *RR464*: updates Attachment W's index of grandfathered agreements with changes identified during the annual review.
- *RR466*: cleans up the transmission owner selection process' governing documents to more accurately capture their intent and execution.
- *RR454*: modifies business practices to increase the deadline for issuing notifications to construct from 15 business days to 45 calendar days.
- *RR458*: adds additional generator interconnection change to reduce and ultimately clear the queue backlog as part of the SCRIPT process.
- *RR467*: revises the tariff's Attachment AQ by reducing the waiting period for preliminary study results of new load additions to adding a rolling submission and response window and posting delivery point network studies once the new or modified load is confirmed. ■

A celebrated gold star from AEP's Richard Ross. | © RTO Insider LLC

— Tom Kleckner

SPP News

SPP Strategic Planning Committee Briefs

Task Force Suggests Framework for DC Ties' Use

SPP's Strategic Planning Committee last week approved a task force's recommended framework to manage DC tie revenue-requirement recovery as part of the grid operator's proposed RTO West.

The DC Tie Task Force's proposed market efficiency use (MEU) mechanism would compensate DC ties for their market use and be applied to DC-tie market dispatch beyond network and point-to-point use. The group said that would ensure their market use is properly compensated for and does not adversely affect the DC tie's host zone.

The task force also said SPP staff should continue to engage with Western parties and its membership to fully develop an MEU rate and applicability details before April 15 and suggested a DC tie congestion-hedging task force develop a final proposal for a congestion-hedging methodology.

Basin Electric Power Cooperative's Tom Christensen was the lone SPC member to vote against the task force's motion, citing concerns with continued congestion and increased maintenance costs for the 200-MW DC tie in Rapid City, S.D., that Basin co-owns with Black Hills Power and Light.

"With significant use, we expect maintenance costs to increase," he said. "Our most significant concern ... is that whatever approach is selected needs to provide an incentive for other entities to join the SPP West effort and for other DC ties to be constructed. Without that, the benefits to both East and West will be unnecessarily constrained. We encourage a more holistic, broader view of what we consider a very substantial opportunity."

Tom Christensen, Basin Electric | *SPP*

SPP would be the first RTO to consolidate two balancing authorities DC ties with its Western membership. A Brattle Group study found that RTO West would produce $49 million in annual savings for current and new members. Western utilities would receive $25 million a year in adjusted production cost savings and revenue from off-system sales. Members in the Eastern Interconnection would benefit from $24 million in savings because of the market's expansion, transmission network and generation fleet.

Assuming FERC approval of Tariff changes, SPP expects RTO West to become a reality in 2024. The gird operator already manages the Western Energy Imbalance Service market, which launched in February, for eight participants.

'Custom' Cost Allocation Coming?

SPP Engineering Vice President Antoine Lucas told the committee that the grid operator's joint targeted interconnection queue (JTIQ) project with MISO will involve a custom cost-allocation approach "designed to fit this study and process." The mechanism will also help the staffs overcome some of the hurdles they have faced in trying to work together on interregional projects.

Lucas said one rubric being discussed is how to allocate portions of different loads and how to allocate generation to the various generators involved in the process. (See *MISO, SPP: Economics Secondary in Joint IC Planning*.)

Separating cost allocation from the rest of the JTIQ work will help the project remain on track, Lucas said. A draft report will be drafted later this month.

Renewable developers are commending the JTIQ project, NextEra Energy Resources' Matt Pawlowski said in speaking for the community.

"It's evident from the last meeting that you're working hard together to come up with solutions," he said. "There's potential to get a lot of these projects built and it will unlock a lot of value for folks. We continue to strive for more certainty on the cost and the schedule, as we do for all interconnection schedule, so we know what we're signing up for. The closer we get to that, the more projects we'll build."

Competitive Upgrade Changes

The committee approved a task force's recommendation to amend a business practice that the group said will improve the volume and quality of submissions in SPP's competitive transmission-upgrade process.

The Transmission Owner Selection Process Task Force modified Business Practice 7650's language so that its criteria for detailed project proposals clarify that they are equivalent to a transmission project in the recommended portfolio. The submitted projects will need to reduce thermal loading below 100% or improve the per-unit voltage values between 0.9/unit and 1.05/unit and also be within 50% of congestion mitigation for each economic need solved.

SPC also agreed with the task force's proposal to require incentive points be considered by the industry expert panel (IEP) responsible for grading and selecting the transmission owner to build a competitive project. That is a policy change from the current practice of not placing any parameters on the IEP. The task force did retain tariff language allowing the panel to recommend a project besides the one with the highest score.

"We feel the incentive points are an integral part of the process," said American Electric Power's Brian Johnson, the task force's chair.

Altenbaumer Ends Chairmanship

Board of Directors Chair Larry Altenbaumer ended his two-year term as the SPC's chair on a high note, ending the meeting just three minutes short of its scheduled end time.

"I couldn't be more excited about SPP's future, and I look forward to working with all of you in other formats in the future," he said before the meeting adjourned.

Altenbaumer will be replaced by Director Mark Crisson.

The SPC will also need to replace Evergy's Kevin Noblet and Nebraska Public Power District's Traci Bender next year. Noblet is leaving Evergy, and Bender's term has ended. ■

— Tom Kleckner

Company Briefs

Ameren Announces Next CEO

Ameren last week announced that Marty Lyons will replace Warner Baxter as president and CEO, effective Jan. 1.

Lyons joined Ameren in 2001 as vice president and controller. He served as chief financial officer for a decade and is currently president of Ameren Missouri.

Baxter will become executive chairman, and Lyons will report to him.

More: *St. Louis Post-Dispatch*

Ares-managed Funds to Buy Majority Stake in Apex Clean Energy

Funds and other accounts managed by the Infrastructure and Power strategy of Ares Management Corporation last week agreed to buy a controlling interest in Apex Clean Energy. Financials were not disclosed.

The investment by the Ares-managed funds will provide Apex with more equity growth capital to help it transition to a pure-play renewable energy independent power producer, the announcement said.

Subject to customary approvals, the deal is set to finalize by the end of the year.

More: *Renewables Now*

BP Purchases Blueprint Power

BP last week announced it has acquired tech company Blueprint Power, which claims to use algorithms to connect commercial buildings to power markets and allows their owners to sell surplus energy stored in batteries or generated by solar panels.

Blueprint already works with five commercial real estate owners in New York to use more than 100 million square feet of property to generate 13 MW of renewably sourced power. BP and Blueprint hope to increase to 36 MW by the end of 2022.

More: *Houston Chronicle*

GM Extends Bolt Production Halt for 2 More Weeks

General Motors last week said it will extend its production halt of the Chevrolet Bolt for two additional weeks as it works to accelerate production of new battery modules and prioritize recall repairs.

In August, the automaker widened its recall of the Bolt to more than 140,000 vehicles to replace battery modules and address fire risks. GM's Orion Assembly plant in Michigan, which builds the Bolt, has been idled since Aug. 23 and will be down through at least the end of October.

GM also said its battery partner, LG Electronics, agreed to reimburse it for the $2 billion estimated costs and expenses associated with the Bolt recall.

More: *Reuters*

Quiniones Named CEO of ComEd

ComEd last week announced that Gil Quiniones will become its CEO, effective Nov. 15.

Quiniones, who has served as president and CEO of the New York Power Authority for the past 10 years, will report to Calvin Butler, CEO of Exelon Utilities, who has been serving as interim CEO since Oct. 1.

According to a company release, Quiniones has more than 30 years of relevant leadership and operational experience across regulated utility markets, the public and private sectors, and state and local governments.

More: *ComEd*

Federal Briefs

Biden Admin. Plans Wind Farms Along Entire US Coastline

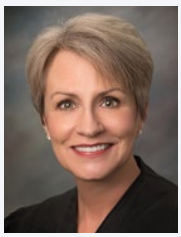
The Biden administration last week announced a plan to develop large-scale wind farms along nearly the entire coastline of the United States.

Speaking at a conference in Boston, Interior Secretary Deb Haaland said the agency will begin to identify, demarcate and eventually lease federal waters in the Gulf of Mexico, Gulf of Maine and off the coasts North Carolina, South Carolina, California and Oregon to wind power developers by 2025.

Biden has pledged to cut the nation's fossil fuel emissions 50% from 2005 levels by 2030 by designing policies to promote the use of electric vehicles and clean energy. In particular, the administration has pledged to build 30,000 MW of offshore wind by 2030.

More: *The New York Times*

Court Pauses New Montana Colstrip Law



In an order last week, U.S. District Judge **Susan Watters** paused a new Montana law empowering State Attorney General Austin Knudsen to order power plant repairs and impose fines of $100,000 a day against noncompliant Colstrip owners. Watters said the law is likely unconstitutional, an issue that she will address later.

The lawsuit concerns Senate Bill 265, which requires all litigation involving the plant owners take place in Rosebud County, where Colstrip resides. The ownership agreement that has been in effect for nearly 40 years specifies that legal matters be settled in Spokane Superior Court in Washington. The contract also spells out how decisions about maintenance and operations are made. In empowering Knudsen to order repairs, the state has overridden portions of the contract.

Knudsen received maintenance policing powers in May, when Senate Bill 266 was signed into law by Gov. Greg Gianforte. The law attempts to prevent the majority owners of the coal-fired power plant from winding down maintenance as they prepare to exit in 2025.

More: *Montana Standard*

DOE Announces $13.5M for Sustainable Development of OSW

The Department of Energy last week announced $13.5 million in funding to provide critical environmental and wildlife data to support the development of offshore wind.

In support of a joint interagency goal to develop 30 GW of offshore wind by 2030, the department is funding four projects that will inform siting, permitting and help protect wildlife and fisheries as deployment increases.

Two of the selected projects will support wildlife and fisheries monitoring efforts on the East Coast, while the other two are focused on preparing the West Coast for floating offshore wind development by collecting wildlife distribution data and developing tools to monitor environmental effects.

More: *DOE*

Katz Appointed Director of FERC's New Office of Public Participation

FERC Chairman Rich Glick last week announced **Elin Katz** will lead the commission's new Office of Public Participation (OPP).

Katz most recently served as vice president of utilities for Tilson Technology Management, where she led the company's utilities practice in support of utility initiatives for grid modernization, connected communities, energy equity and storm response.

FERC established OPP in June to coordinate and aid members of the public to facilitate participation in commission proceedings.

More: *FERC*

Shore to Lead Six-state EPA Region

The EPA last week tapped Debra Shore as the top administrator of the agency's six-state regional headquarters in Chicago.

Shore will oversee the federal government's protection of water, air and land against polluters in Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin. In turn, she will have to resign from her commissioner position with the Metropolitan Water Reclamation District of Greater Chicago.

More: *EPA*

US, EU Line Up Global Pledges to Slash Methane Emissions

At a virtual meeting in Brussels last week, European Union Climate Negotiator Frans Timmermans and White House Special Envoy for Climate John Kerry announced that 24 additional countries have signed up for a global methane pledge that vows to cut methane emissions by 30% by 2030. In all, 34 counties have signed the pledge.

The pledge is now backed by nine of the world's top 20 methane-emitting countries, which account for 60% of the global economy. However, with just a month left before a climate summit in Scotland, some of the world's biggest methane emitters — including Russia, China, India and Brazil — have still not signed on.

More: *The Washington Post*

State Briefs

ARIZONA

Phoenix Adopts Updated Climate Action Plan

Phoenix Mayor Kate Gallego and the city council last week adopted a climate action plan to cut emissions by approving the city's comprehensive action plan to reach its net-zero goal a decade or more earlier.

The move sets a goal to reach net-zero emission by 2050 or sooner and adds a specific 50% reduction in emissions by 2030.

Last month the city council approved $2.8 million in the 2021-2022 budget for climate and heat related staff, resources and investments.

More: *AZ Big Media*

CALIFORNIA

Port of San Diego to Electrify Freight Trucks, Cranes, Tugboats by 2030

The Port of San Diego Board of Commissioners last week pledged to transition to battery-electric or some other zero-emission technology by 2030. The goal — part of the Maritime Clean Air Strategy — comes five years ahead of a state-mandated transition for heavy-duty trucks and exceeds efforts at the ports of Long Beach and Los Angeles.

The pledge has several short-term goals, including requiring at least 40% of freight trucks that visit the terminals in Barrio Logan and National City to be zero-emission by 2026. The Maritime Clean Air Strategy also calls for transitioning diesel cargo-handling equipment, such as cranes, drayage trucks and forklifts, to zero-emission technology by 2030.

More: *The San Diego Union-Tribune*

INDIANA

Elkhart County Denies Zoning Change, Ends Plans for Solar Farm

Elkhart County Commissioners last week voted to deny zoning changes for a proposed $120 million solar farm despite the county council unanimously approving the project's economic development agreement.

Commissioner Brad Rogers said there were "positives and negatives" to the project but cited the concerns of residents, which included property values and worries that the project would ruin the area's rural character. Commissioners Frank Lucchese and Suzanne Weirick cited similar reasons for denying the zoning change.

More: *WVPE*

LOUISIANA

State Lands Largest Carbon Capture Energy Project in the World

Gov. **John Bel Edwards** and Air Products last week announced that the state has landed the largest clean energy carbon sequestration project in the world.

Air Products said it will

build a $4.5 billion complex to produce "blue hydrogen," which uses natural gas to produce an alternative fuel, with the carbon dioxide emissions captured and stored underground. The hydrogen created in Louisiana will be supplied to Air Products customers around the Gulf Coast and will be used to make ammonia that will be transported internationally and converted back to blue hydrogen.

The new facility will be operational in 2026.

More: *Lafayette Daily Advertiser*

MICHIGAN

DTE Energy to Stop Burning Coal at Belle River in 2028

DTE Energy last week said it will end coal use at its Belle River Power Plant by the end of 2028 to hasten its carbon emissions reductions. If so, it would be two years ahead of schedule.

The idea is to more quickly meet its goal to drop carbon emissions by 50% by 2030 — now with a goal for 2028.

The Belle River site will be converted to a renewable power generator after officials evaluate options.

More: *MLive*

MISSOURI

Commission Says Permit for Ameren Coal Plant Issued Lawfully

The Clean Water Commission last week voted 4-1 to affirm an Administrative Hearing Commission (AHC) ruling when it said that a 2015 permit issued by the Department of Natural Resources (DNR) for Ameren Missouri's coal-fired Labadie Energy Center was lawful. The Sierra Club had challenged the permit, alleging it violated the Clean Water Act.

Labadie takes in water from the Missouri River to cool the plant and discharges the heated water downstream.

From the late 1990s until 2015, environmental regulators at the DNR allowed the plant to operate under an expired permit that allowed it to occasionally break standards for its hot water discharges. When the DNR issued a new permit in 2015, the Sierra Club appealed to the AHC, saying the agency failed to determine the best available technology to minimize the hot water flowing into the river. The AHC sided with DNR in July, issuing a ruling two years after holding arguments in the case.

More: *Missouri Independent*

NORTH CAROLINA

Cooper Signs Major Energy Law

Gov. **Roy Cooper** last week signed an energy bill that aims to reduce greenhouse gas emissions from the state's power plants by 70% from 2005 levels by 2030.

The Utilities Commission will be tasked with coming up with arrangements to meet the carbon dioxide reduction goals sought by the governor. One way being discussed is to retire Duke Energy's coal-fired plants early.

More: *The Associated Press*

OHIO

Penn. Energy Marketer Agrees to Refunds, Waive Bills Over Sales Tactics

The Public Utilities Commission last week agreed to a second settlement with natural gas and electricity supplier PALMco Energy and barred the company from operating in the state for seven years following allegations it used misleading and deceptive sales tactics.

PALMco also agreed to refund more than $200,000 to customers and waive $800,000 in bills.

More: *The Columbus Dispatch*

PUCO Shouldn't Have Approved FE Affiliate, Supreme Court Rules

The state Supreme Court last week ruled that the Public Utilities Commission should not have approved FirstEnergy Advisors, an Akron-based FirstEnergy affiliate, to help consumers shop for electricity.

In April 2020, the PUC and Chairman Sam Randazzo approved FirstEnergy Advisors as a "competitive retail electric service provider." Brokers were an alternative to purchasing energy from a distribution company and, by bringing customers together, could negotiate better prices. However, the Consumers' Counsel and the Northeast Ohio Public Energy Council opposed the application, saying that the applicant shared a parent company and several executives with the distribution companies. PUC staff ultimately disagreed with consumer advocates, saying that FirstEnergy Advisors intended to comply with all commission rules and recommended that it be approved.

The advocates then sued and brought the case to the Supreme Court, which ruled that it should not have been approved. The Court has sent the matter back to the PUC for additional hearings.

More: *The Cincinnati Inquirer*

OREGON

PGE Ramps Up Clean Energy Plans

Portland General Electric last week filed new plans with the Public Utility Commission to update the power grid and purchase 1,000 MW of clean energy capacity.

The utility is facing new state mandates to eliminate greenhouse gas emissions from its electricity by 2040, as lawmakers passed a bill earlier this year that requires PGE and Pacific Power to cut emissions by 80% in the next 10 years.

More: *Oregon Public Broadcasting*

VIRGINIA

Dominion Energy to Resume Disconnections

Dominion Energy last week began calling customers to let them know that the utility is planning to resume service disconnections for nonpayment beginning Nov. 8.

Those at risk are customers who are two months behind in payments.

More: *WWBT*