RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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Gen. Owners, Other Suppliers Key to EOL Win

By Rich Heidorn Jr.

PJM's load-side stakeholders were disappointed last month when they failed in their bid to give the RTO control over end-of-life (EOL) transmission planning.

But the joint stakeholders rebounded at the June 18 Members Committee meeting, recording a 69% win that culminated more than four years of battles with PJM's Transmission Owner sector. The victory sets up a showdown at FERC with the TOs, which filed their own EOL proposal with the commission on June 12. (See *PJM Stakeholders Endorse End-of-Life Proposal*.)

How did the joint stakeholders pull off their comeback, after falling short in votes in May? A review of voting records and interviews with more than a dozen stakeholders indicate it was the joint stakeholders' gains among the Generation Owners and Other Suppliers sectors that turned the vote after days of intense lobbying by both sides.

PSE&G's Kingsland-Hudson reliability project in Kearny, N.J. | *Kiewit*

"In all the time I've been involved in the stakeholder process, I've never seen so much outreach on an issue," said Ed Tatum, vice president of transmission for American Municipal Power, which led the joint proposal with Old Dominion Electric Cooperative (ODEC), the PJM Industrial Customer Coalition (ICC) and LS Power. "That includes PJM and the [TOs] as well as our group."

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TOs Demand PJM Reject EOL Proposal (p.41)

'Astonishing' Buildout Needed for Clean NY Grid

By Michael Kuser

Meeting New York's ambitious clean energy goal of having the first grid in the country to reach 100% emissions-free electricity will require an "astonishing" 80 GW of new generation by 2040, NYISO stakeholders heard last week.

Brattle Group representatives presented the Installed Capacity/Market Issues Working Group their final *analysis* of the state's evolution to a zero-emission power system on June 22.

The report included three "alternative scenarios" modeling operations and investment in scenarios of increasing electrification for the years 2024, 2030 and 2040, as stakeholders had requested when presented the base case modeling in May. (See *NYISO Examines 'Evolution' to Zero Emissions*.)

"This is a sweeping study of a complete transformation of the system over the next two decades," Brattle's Sam Newell said. "By 2030 the system would need about 35 GW of additional wind and solar to meet the 70% renewable goal, and 80 GW relative to today of new wind and solar by 2040 to get to zero carbon."

Signed into law last July, New York's Climate Leadership and Community Protection Act (CLCPA) mandates, among other targets, that 70% of the state's electricity come from renewable resources by 2030 and that generation be 100% carbon-free by 2040. (See *Cuomo Sets New York's Green Goals for 2020*.)

"That means adding about 4 GW per year of onshore wind, offshore wind and solar in some combination," Newell said. "That's an astonishing pace."

As part of its "Grid in Transition" initiative, the

Continued on page 26

Bulk Tx, 115-kV Upgrades Needed for NY '70x30' Goal (p.23)

CPUC Calls FERC Tx Incentive Plan 'Atrocious'

By Hudson Sangree

California Public Utilities Commission members on Thursday voiced their disapproval of FERC's proposal to double its transmission incentive adder and make the bonuses easier to get, calling the plan "disgusting," "appalling" and enough to make "one's blood boil."

The commissioners made their comments before voting unanimously to authorize CPUC lawyers to file comments with FERC opposing a March 20 Notice of Proposed Rulemaking to update its transmission incentives policy (*RM20-10*). (See *FERC Proposes Increased Tx Incentives*.)

"I think that my 6th grade teacher Sister Augustine would have captured this moment really well because, 'It is atrocious,' as she would say," Commissioner Martha Guzman Aceves said. "The greed in the time of such economic recession is just atrocious."

CPUC President Marybel Batjer | *California State Assembly*

CPUC President Marybel Batjer took the opportunity to wish for a shakeup at FERC.

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In this week's issue

FERC/Federal News

FERC, RTOs Need to Set Hybrid Rules, Experts Say

By Tom Kleckner

First came the wind turbines, then solar panels. Battery storage followed, and now RTOs and ISOs are faced with integrating hybrid energy resources.

The main barrier to their integration? The RTOs and ISOs themselves.

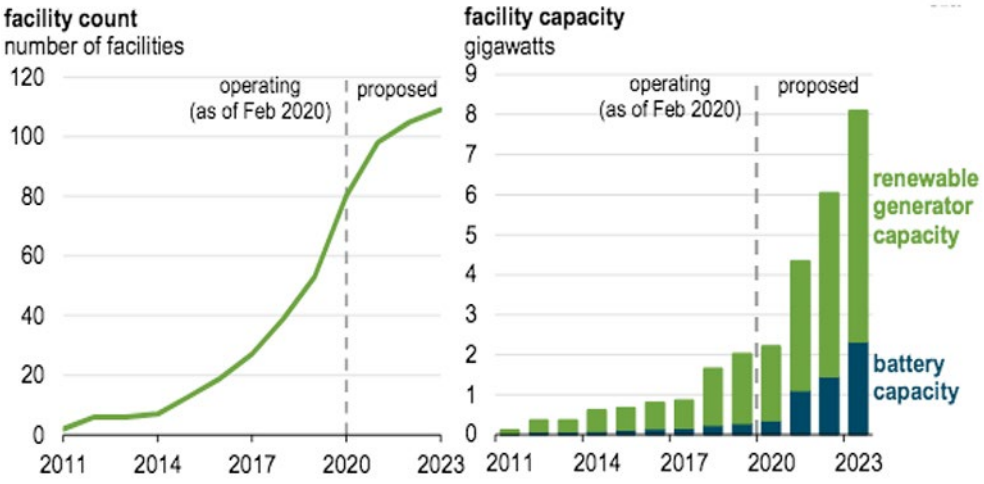
"All of the markets are having conversations but in different stages and with different scopes," said Jason Burwen, vice president of policy for the U.S. Energy Storage Association, during a recent online panel discussion facilitated by his organization. "We are starting to see how different markets are going to take this on."

Grid Strategies President Rob Gramlich, who last year authored a *paper* for the ESA on the subject, says regulations have not kept up with technology and the markets. He thanked FERC for pursuing "some" reforms but noted the commission's recent orders on storage (841) and interconnections (845) don't address hybrid resources.

"It's been just incredibly fast how much the market has changed," he said during ESA's June 11 discussion. "Hybrid doesn't even appear in those rulemakings. That's not the fault of FERC. It's just that nobody raised it. The market has moved faster than policy."

Hybrid resources are generally considered to be co-located pairings of two different technologies. Most of these resources consist of solar or wind installations paired with batteries, the "core technology driving hybridization," Gramlich said. Batteries are highly scalable and modular, making them suitable for generation sites, integrating them into the wires' infrastructure or locating them with the customer.

Rob Gramlich, Grid Strategies | © *RTO Insider*



Hybrid resources are filling up interconnection queues. | *Grid Strategies*

Solar PV generation is the most common resource paired with batteries, but other configurations include wind-battery, gas-battery and hydro-battery. These resources' ability to respond to economic signals differently than traditional generators has driven their recent growth.

According to the U.S. Energy Information Administration, some 4.6 GW of hybrid capacity is currently installed, with another 14.7 GW of capacity in the immediate development pipeline. More than 40 GW of hybrids entered generator interconnection queues last year, pushing the total hybrid capacity in RTO/ISO queues to 69 GW.

Hybrid costs are also coming down, further increasing their attractiveness. Gramlich said power purchase agreement prices in the U.S. dropped from $40 to $70/MWh in 2017 to $20 to $30/MWh in 2018 and 2019, mostly because of falling technology costs and tax credits.

"There are big opportunities for adding storage to existing generation. The main problem is the interconnection queues are very slow," he said. "Everyone knows the interconnection queues are a constant challenge. If one can make a more efficient use of the interconnection service with an existing service or one that's made it through some stages of the queue, that's an efficient way to go."

"Order 841 opened the floodgates. Hybrids weren't previously on the radar," said Rhonda Peters, a principal with InterTran Energy Consulting. "All of a sudden, you had this ability to take variable generation and make it more dispatchable [with energy storage]. But having that ability didn't mean it was actually possible because we didn't have policies that allowed for it."

The panel members all called for FERC and the grid operators to get serious about hybrid resources. In his paper for ESA, Gramlich said some near-term changes can be made to improve integration of the resources by treating them as two separate units and harmonizing their participation models.

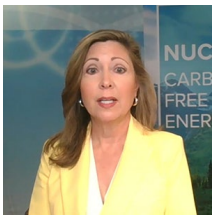
"However, for hybrid resources to deliver their full value, they may eventually need to be treated as fully integrated single machines, able to optimize what they provide and when they provide it," he said, noting RTOs' and ISOs' current rules do not allow for this flexibility.

"We're starting to see how different markets are starting to take this on," Burwen said, indicating ERCOT and CAISO are taking the lead. "ERCOT plans to use an energy storage model for hybrids. That's instructive of the direction we're going. Participating as conventional generation might make more sense than [being paired with] existing resource types. It sets a market for where we think you're going to make the best use of hybrids." ■

FERC/Federal News

NEI Emphasizes Collaboration with Renewables

By Michael Brooks



NEI CEO Maria Korsnick | *NEI*

Nuclear Energy Institute CEO Maria Korsnick is always upbeat and optimistic about the future of nuclear energy when she makes her annual State of the Industry address, emphasizing plants' emissions-free nature, high capacity factors and reliability.


Monica Trauzzi, NEI | *NEI*

Korsnick's *address* this year, conducted online as it has been for the last two years, was no different. (See *NEI Sees Glass Half Full for Nuclear Industry* and *NEI CEO: FirstEnergy Emergency Request a 'Bridging Strategy'*.) But after the usual quick, bright and positive speech and soft question-and-answer with NEI spokeswoman Monica Trauzzi, NEI on Wednesday hosted a panel discussion featuring Union of Concerned Scientists President Ken Kimmell and Renewable Energy Buyers Alliance (REBA) CEO Miranda Ballentine. Both expressed general support for nuclear's role in a future, zero-carbon generation mix, though both couched it with contingencies.

In her opening speech, Korsnick positioned nuclear not as a competitor with renewables but as a partner. Though she noted that nuclear provides more than half of all carbon-free generation in the U.S. (as she did last year), "I want to be absolutely clear: We need to develop every source of carbon-free energy that we can. The world is counting on carbon-free resources to complement one another, not just compete. Our choice isn't between nuclear power or wind and solar. It's between a status quo of rising emissions from fossil fuels or a low-carbon future from all available sources, including nuclear."

As evidenced by its name, REBA members — consisting of large corporations such as Facebook, Google and Walmart — have focused their procurement targets on renewable resources, particularly utility-scale wind and solar. But Ballentine said that "there has been a fairly significant transformation in the mindset of large clean-energy buyers, actually quite recently I would say ... from goals of 100% renewable energy, to now companies thinking about 24/7/365 zero-carbon power, where renewable energy is one means to that end."

REBA members "are beginning to think about other forms of zero-carbon power" besides large wind and solar projects, Ballentine continued. She listed geothermal, landfill gas and hydropower, "which is the one that tends to get left out of the discussions so frequently."

But she said nuclear presents unique concerns for the organization: "What do we do with the waste, how do we handle proliferation, and how do we handle safety? ... To the extent that new nuclear [technology] addresses some of those three core challenges of the existing fleet ... I think you're going to start seeing large consumers of power being more interested in the potential role that new nuclear can play."

Kimmell emphasized "the herculean challenge" of not only using 100% clean energy but electrifying transportation and building heating. "This is a gigantic challenge that implies a pace of expansion of our electric grid in a way that we've never come close to doing in history," he said.

Ballentine agreed. "I would say that many of the members in REBA ... have a sense of urgency around the timeline that even 2050 for the power system is too late because there are so many other parts of our economy that are much harder to decarbonize."

"To meet a challenge like" avoiding permanent climate change, Kimmell said, "all of us need to be prepared to abandon a tribalistic attachment to particular solutions."

ClearPath Executive Director Rich Powell, who moderated the panel, echoed those sentiments. "I think that lesson of stopping being against the things we're not specifically for — and eventually becoming for the things we're not specifically for — is ... just a crucial mental frame to adjust [to] as we respond to a challenge this enormous." ClearPath, formed in 2014, seeks to "develop and advance conservative policies that accelerate clean energy innovation."

Kimmell warned, however, that UCS' support for nuclear power was conditioned on maintaining the Nuclear Regulatory Commission's strict safety regulations for plants. "And I should say this is an area where it's hard for us to work cooperatively because we don't support efforts to relax those standards, and to the extent that those standards do get relaxed, we're going to need to reconsider that criteria" of support, he said.

He also said any financial support through legislation should be reserved for plants that "meet or exceed the NRC's highest safety standards." He pointed to UCS' 2018 *report* that recommended policies such as a national carbon tax or clean energy standard that would prevent existing nuclear plants from retiring earlier than their expected useful life. ■

ClearPath Executive Director Rich Powell (top left) moderates a discussion with REBA CEO Miranda Ballentine and UCS President Ken Kimmell. | *NEI*

CAISO/West News

FERC Clarifies Western EIM Order

Denial of Net Export Limit Justified, Commission Says

By Hudson Sangree

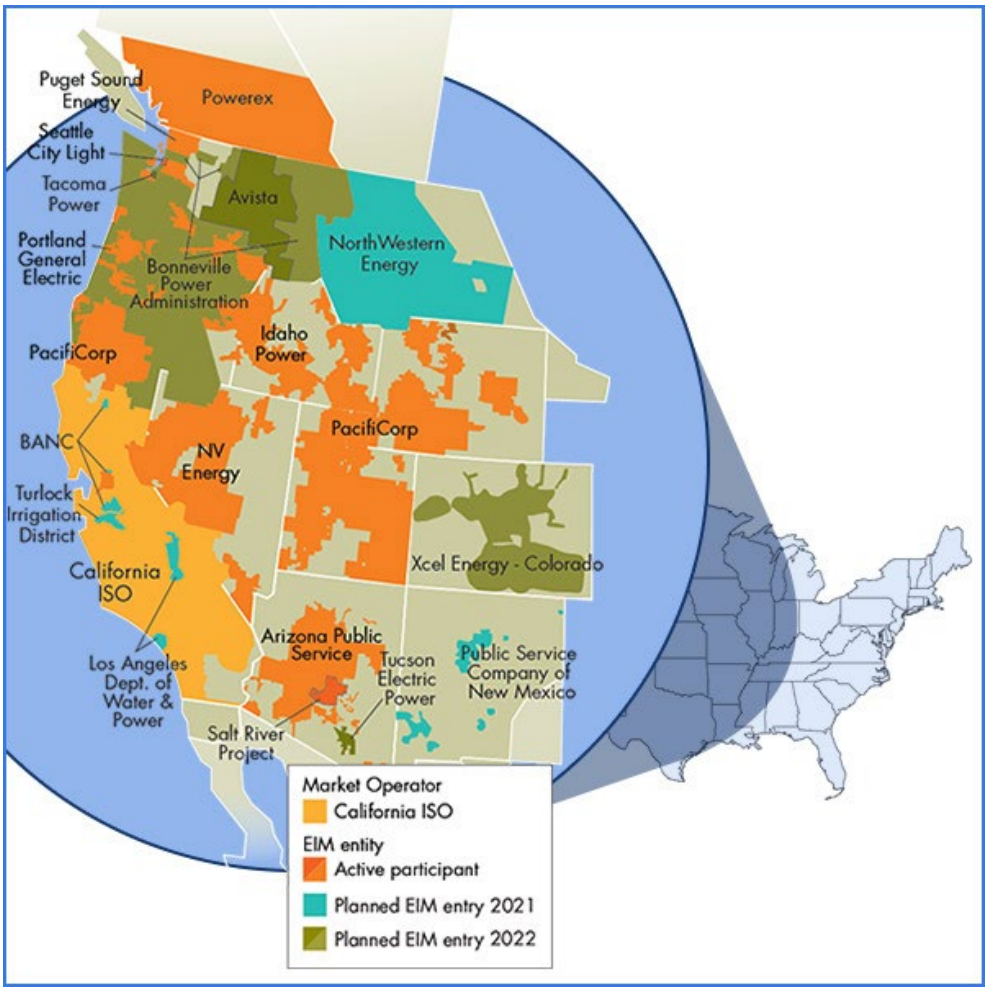
FERC on June 18 denied CAISO's request to reconsider its rejection of the ISO's proposal to adopt a "net export limit" to help entities in the Western Energy Imbalance Market avoid unintended consequences of market power mitigation.

But the commission's order denying rehearing clarified that its initial ruling did not imply that unmitigated bids would be effective in determining LMPs for serving load in an import-constrained balancing authority area (BAA) subject to local market power mitigation (*ER19-2347*).

The commission's original Sept. 19, 2019, order nixed the ISO's proposal to introduce a net export limit that would have allowed EIM entities to limit the additional dispatch of resources when resources' bids are reduced because of their BAAs becoming subject to bid mitigation. (See *CAISO Goes 2 for 3 on EIM Hydro Rule Changes*.)

As FERC explained in its order, "the optional feature would [have allowed] EIM entities to limit net transfers out of the mitigated BAA to the greater of: (1) the pre-mitigation transfer quantity, or (2) the base transfer quantity, plus, for both (1) and (2), the sum of the flexible ramping up awards in the market power mitigation run in excess of the BAA's flexible ramping-up requirement."

CAISO intended to enforce the rule in both the 15-minute and real-time markets to ensure that every interval limit was determined separately.



Active and pending participants in the Western EIM | *CAISO*

In rejecting the provision, FERC ruled that it was "inconsistent" with the EIM's market power mitigation framework and "not an appropriately calibrated solution to the concerns CAISO identifies."

"In particular, CAISO's proposal could weaken CAISO's market power mitigation process by allowing EIM entities to withhold generation through the submission of high supply bids and restricting EIM transfers out of their BAAs," the commission wrote.

In seeking rehearing, CAISO argued that there was no evidence supporting FERC's conclusion that the proposed net export limit would encourage EIM entities to withhold generation. In fact, the ISO said, the net export limit would encourage suppliers to offer greater levels of supply into the EIM because "it was designed to eliminate the existing incentive for an EIM entity, if it wishes to limit the amount of energy that its resources may have to sell at mitigated prices, to only offer the minimum amount of required supply."

FERC didn't buy that argument.

"We are concerned that CAISO's proposed incentive for greater participation in the EIM is likely to produce outcomes that are not just and reasonable. Contrary to CAISO's assertions, the direct effect of the proposed net export limit would be to allow EIM entities to limit the dispatch of their resources if they are mitigated in the market power mitigation run," FERC wrote.

In its motion for clarification, CAISO faulted FERC for "failing to explain how the existing local market power mitigation system and the participation in the proposed net export limit feature can result in 'unmitigated bids … determin[ing] the dispatch to serve load outside of the EIM entities' BAAs.'"

FERC said that wasn't the case.

"We acknowledge that all supply bids in an import-constrained BAA would continue to be subject to mitigation under CAISO's proposal. However, the proposed net export limit would allow an EIM entity to cap its net transfers, and the restriction on supply would affect dispatch in the exporting BAA and in other BAAs," it said. ■

CAISO/West News

CPUC Calls FERC Tx Incentive Plan 'Atrocious'

Continued from page 1

"This body has got to change. Unfortunately, they're termed," Batjer said of the federal commissioners, who serve five-year terms. "But [the nation] clearly needs some better thinking and better logic coming out of FERC. There's no doubt about it.

"I think 'appalled' is another word that comes to mind besides 'atrocious,'" she said.

The NOPR that outraged the California commissioners proposes a new approach to awarding transmission incentives and a doubling of the adder for participating in an RTO from 50 to 100 basis points. It would shift the policy away from awarding benefits based on the risks and challenges of a transmission development project to one focused on economic and reliability benefits.

FERC, which gained authority to issue incentives in the Energy Policy Act of 2005, implemented its policy in Order 679 in 2006. Last March, it opened a docket to reconsider its policy, prompting disagreements among stakeholders over the course FERC was taking. (See *Stakeholders Spar in FERC Tx Incentives Docket*.)

In general, those that stand to profit from the change support the policy, while those who would pay oppose it. The CPUC is intervening on behalf of California ratepayers, who could end up paying hundreds of millions of dollars unnecessarily, commissioners and staff members said.

"Staff have overarching concerns with FERC's untenable rationale for now making these incentives far easier to obtain and far more lucrative for transmission owners," CPUC lawyer Jonathan Knapp told the commission Thursday, paraphrasing a staff *memorandum* he co-wrote.

FERC Commissioner Richard Glick | © *RTO Insider*

CPUC headquarters in San Francisco | © *RTO Insider*

Because of "dramatically increased levels of investment in transmission infrastructure and widespread reduction in transmission congestion, these incentives are not needed, particularly in the CAISO's control area," he said.

'Head Scratcher'

When it directed FERC to issue the incentives in 2005, Congress relied on projections that the incentives would lower costs for ratepayers as demand for electricity grew, Knapp said. That turned out to be wrong, he said. In CAISO, transmission charges have increased 300% since 2006, while demand has decreased 5%, he said.

FERC lacks data showing the incentives worked, and "everything points in the opposite direction," he said.

That's why the proposed changes don't make sense, Knapp said.

"Most fundamentally, FERC now proposes to ignore the definition of an incentive — something that encourages a person to do something — but instead proposes to essentially award bonuses to transmission owners for developing projects that they would already have undertaken or to take actions that in some instances are required by state law," the lawyer said.

One of the changes would remove the requirement that TOs must voluntarily participate in an ISO or RTO to receive the adders. State law requires investor-owned utilities to participate in CAISO, but under the proposed FERC changes, the IOUs would get the doubled adder for remaining in CAISO, Knapp said.

He cited FERC Commissioner Richard Glick's dissent to the March 20 decision calling the proposed change "the biggest head scratcher."

PUC Commissioner Clifford Rechtschaffen said that the proposed changes would give Pacific Gas and Electric $145 million a year for "just showing up."

In two decisions in 2018 and 2020, FERC ruled that CAISO participation is voluntary and that PG&E and other IOUs deserve the return on equity incentives. FERC upheld its original 2018 ruling on March 17 on remand from the 9th U.S. Circuit Court of Appeals. (See *FERC Rejects RTO Incentive Adder Rehearing*.)

CPUC Commissioner Genevieve Shiroma said FERC ignored the 9th Circuit and decided to "double-down on the incentives … inexplicably."

"Who's paying for all this? The customers are paying for all of this," Shiroma said. "And especially during this time of high unemployment, the pandemic — it's not going to go away soon." ■

ERCOT News

Companies Debate When to Bring Back Staff

ERCOT, AEP Find Employees Productive When Working Remotely

By Tom Kleckner

The world changed for American Electric Power's Scott Smith in early March when the coronavirus pandemic forced Ohio Gov. Mike DeWine to partially shut down Columbus' annual professional bodybuilding event.

"The Arnold," as it's called locally, is no ordinary strongman competition. Named after Arnold Schwarzenegger, the *Arnold Sports Festival* annually attracts more than 20,000 competitors from more than 80 countries to Ohio's capital.

"It was a watershed moment for us," Smith, AEP's senior vice president of transmission field service, said last week during an online Gulf Coast Power Association panel discussion.

"It's the largest convention in Ohio, other than [Ohio State University football]," he added.

AEP leadership quickly dusted off a plan it had developed after the H1N1 pandemic in 2009 and by mid-March had sent much of its corporate staff home. Now, AEP's executives are wondering whether they'll even have some staff return to the office.

"We originally thought we would come back to work the same as before, but it's not business as usual," Smith said during the discussion Thursday. "There's going to be the new normal. We're in the beginning stages of figuring out that and the protocols around it."

Smith was joined on GCPA's panel, "The Future of Work in the Age of Pandemics," by ERCOT CEO Bill Magness, who said he has the same thoughts. The Texas grid operator also sent its corporate staff home in mid-March. Their stay-at-home orders have since been extended through September.

"We ended up with about 95% of our people working off-site, and there they remain," Magness said.

ERCOT and AEP have since been using federal guidelines and social-distancing and hygiene practices to determine how best to safely bring back employees. Today's open-office concepts mean companies will have to rely on shields for workspaces and faces if staff are going to return to their workspaces.

"We're not going to be able to keep 6-foot distancing for everyone in their cube," Smith said, noting he sits in an office that is 80% open space.

"We're thinking hard about this," Magness said. "Is it better to maintain the performance of the people on your team by keeping them where they are in a remote environment, or bring them back to the way we used to be? From a business perspective, what's going to help the business the most? What helps the most is productive employees.

"If we only have a somewhat limited number of people in the footprint, we may not be able to bring people back to sit where they use to sit. We may have A Team/B Team arrangements. We're learning a lot about what the future is going to look like. It's been fascinating."

A recent *Upwork survey* of hiring managers revealed that more than half the nation's workforce is working remotely. Managers are planning for almost 22% of their workforces to be entirely remote in five years and for the expected growth rate of full-time remote work during that time to more than double, from 30% to 65%.

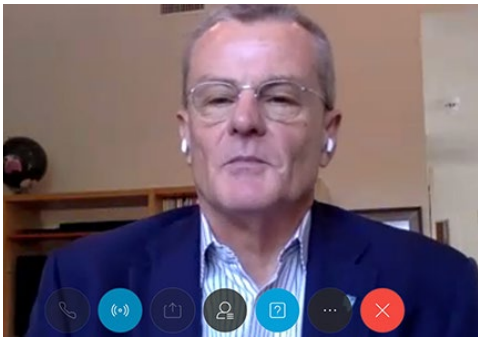
It may seem counterintuitive, but the survey also found 32% of managers say remote work has increased productivity. That's because of a lack of commute, fewer nonessential meetings and distractions than in the office, according to the survey.

"We've learned that we have a lot of employees who can get their work done remotely. We've traditionally never thought that way," Smith said. "We've found the production of a lot of folks is up because they can get things done at home. Their days may extend to 6:30, 7:30 at night because of all the phone calls and time differentials. It's actually very interesting. There are going to be a few persons who have to be at work, but we're questioning who does really need to come back in the office."

"Part of what's challenging is people want to get back to work," Magness said. "We've never stopped working, but people want to get back to their environments. Those environments are not what [they were]."

Staying the Path

In contrast, protecting employees in the field or control rooms is much easier. Smith said AEP's work crews complete health self-assessments each day on an app. If an employee answers positively to one of the questions, their supervisor gets an email that indicates the employee needs to stay home.



ERCOT CEO Bill Magness during a GCPA webinar on the future of work | *GCPA*

"That's our first line of defense: the employee staying home," he said. "We're asking employees, as best they can, to separate themselves with their vehicles. If there are three or four of them working on an issue, we may have three or four trucks at the jobsite, just to maintain social distancing."

Austin-based ERCOT has isolated controllers in its two operations centers in nearby Taylor and Bastrop. When a 12-hour shift ends in Taylor, the next shift begins in Bastrop while the Taylor ops center is sanitized.

Smith said the remote work environment has revealed a need for different ways of communicating. Zoom and Microsoft Teams can only go so far in bringing together staff from disparate locations and instilling a sense of camaraderie.

"It's very hard to replicate face-to-face time with electronic tools," he said. "One of the things we find, like staff meetings on the web, is someone makes a joke, but no one hears anyone laugh. Everyone's on mute. That kills camaraderie right there."

"That's right! That's a terrible thing," Magness responded.

Turning serious, Magness said the current environment has left him pleased with staff's ability to get their work done in a difficult setting.

"From ERCOT's perspective, we're really gratified with the way people have stepped up," he said. "We have to remember this is unusual. This is odd. People will have different reactions to this. We need to constantly think about who we were when we started this, who do we want to be, and how do we stay on that path until this is over." ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

Members Virtually Conduct First Full Meeting Since January

ERCOT's Technical Advisory Committee last week held its first full working meeting — albeit virtually — since the COVID-19 outbreak, endorsing a raft of revision requests, reviewing the committee's strategic goals, and receiving updates from the Real-Time Co-Optimization Task Force (RTCTF).

The committee last conducted a full meeting in January. It has held several information sessions since, taking email votes on changes to the grid operator's protocols and a $219 million transmission project. (See "Corpus Christi Tx Project Gets OK," *ERCOT Technical Advisory Committee Briefs: May 27, 2020*.)

Speaking during a webinar the day after the TAC's meeting Wednesday, ERCOT CEO Bill Magness said staff's "experimentation" with conducting webinars resulted in a meeting "where the TAC was really able to do everything." (See related story, *Companies Debate When to Bring Back Staff*)

"Yesterday showed us we can do things on a remote basis," he said. "[Stakeholder] meetings are still happening and still going on. We're working through a lot of complexities with real-time co-optimization, but those folks aren't missing a beat so far, knock on wood."

The committee and the Board of Directors have already approved the use of roll-call votes during their remote meetings and modified other rules and procedures that compensate for the inability to meet in person. ERCOT's corporate members will convene virtually July 10 to vote on the changes.

In-person meetings will not resume until October, at the earliest — if then.

ERCOT in May *extended mandatory work-from-home rules* through September. Staff can request "limited periods" of on-site work for "business-critical" task that can't be completed remotely, but approvals will be limited and must come from executive leadership, human resources or security and facilities.

ERCOT Finds New Corporate HQ Site

Staff discussed with the committee their plans to move into a new office space, assuring members the new digs would not increase the system administrative fee.

Facing a 2022 expiration on its Austin office space it leases for corporate staff and Independent Market Monitor, ERCOT engaged a commercial real estate firm to find a new one. The grid operator's criteria included at least 35,000 square feet of space, 180 parking spaces, proximity to the city's airport and hotels, and an option to purchase.

Artist rendering of ERCOT's new corporate headquarters | *ERCOT*

The search resulted in a location within the same *MetCenter* business park where ERCOT is currently located. The board this month gave staff the go-ahead to execute an agreement with developers, which is expected to be finalized by the end of July, with construction to begin in August.

The grid operator expects the two-story building to be ready for occupancy by the end of next summer. Construction, equipment and furnishing costs are expected to be about $20 million, with ERCOT expecting to break even within 13 years.

Staff said a lack of meeting space and technology issues are the main reasons they are moving from their home of 20 years. ERCOT supports about 300 stakeholder meetings each year at its MetCenter location.

"With the pandemic, do we even need a MetCenter? The answer is a strong 'yes,'" said Betty Day, vice president of security and compliance. "The number of meetings is increasing."

The new building will include two additional meeting rooms among its 5,000 additional square feet of public meeting space. Informal meeting areas, public booths and phone rooms will also be added.

Day said staff have had "multiple" conversations with the board about the plan. During individual meetings with stakeholders last fall, staff "made stakeholders aware this lease was coming up and we would look at alternatives," she said.

Committee members expressed concern over making a costly real estate decision during a bad economy and encouraged further due diligence. Day said ERCOT felt the project's

ERCOT News

costs were "reasonable."

"We're where we are," Magness said during his online panel discussion. "We had to move on making a decision. As long as there's ERCOT, there'll be meetings. We're moving forward with the real estate decision in this strange environment."

Software Error Results in 'Minimal' Market Exposure

Staff said a software error in ERCOT's credit monitoring and management system resulting from a 2012 protocols change resulted in "minimal" exposure to the market.

Mark Ruane, director of settlements, retail and credit, said errors in a real-time liability forward (RTLF) calculation resulted in a 100% multiplier, rather than the proposed 150% multiplier, being applied to some components of the real-time liability calculation, among other errors.

System limitations kept staff from quantifying the number of instances where an erroneous calculation determined a counterparty's total potential exposure, Ruane said. He said the error may have resulted in either higher or lower RTLF estimates.

Staff patched the error on June 4 by aligning the calculation with the 2012 *Nodal Protocol revision request* (NPRR) that reduced the time frame for an operating day's cash clearing and correspondingly reduced required collateral. ERCOT *notified* market participants of the error that same day.

Given the chance to ask questions, none of the TAC members did.

RTCTF Continues Work

ERCOT's Matt Mereness, chair of the RTCTF, told the TAC that the group met June 22 to consider ancillary services' deployment and recall. Staff walked the task force through a 44-page slide deck in sharing their view and understanding of the process.

"As we develop the protocols, sometimes it's hard to see how everything fits together," Mereness said.

The task force is reviewing 90 of 187 binding document sections. It has reached consensus on 64 sections as it works toward a November deadline to develop real-time co-optimization's protocols.

TAC Endorses Consent Agenda's 16 Changes

The committee unanimously approved a 16-item consent agenda in a voice vote that concluded the meeting. Many of the changes were noncontroversial cleanup items; some removed gray-boxed language that is no longer needed. Four other changes were tabled while waiting on related revisions to pass through the stakeholder process.

The changes included six NPRRs, four changes to the Nodal Operating Guide (NOGRR), three revisions to the Planning Guide (PGRRs), a system change request (SCR), and single revisions to the Resource Registration Glossary (RRGRR) and the Verifiable Cost Manual (VCMRR):

- *NPRR903*: clarifies the deviations that may occur with day-ahead market delays and adds language requiring ERCOT to issue a market notice for any act or omission to ensure the day-ahead process is successfully completed.
- *NPRR973*: adds definitions for generator step-up and main power transformer to the Nodal Protocols and clarifies their uses.
- *NPRR983*: deletes remaining gray-boxed language associated with *NPRR257* (Monitoring Programs and Changes to Posting Requirements of Documents Considered CEII).
- *NPRR990*: deletes the remaining gray box for *NPRR889* (RTF-1 Replace Non-Modeled Generator with Settlement Only Generator) and relocates the defined term "combined cycle train" from "Resource" to "Resource Attribute."
- *NPRR992*: ensures the day-ahead liability estimate correctly includes ERCOT contingency reserve service charges and payments, as intended by *NPRR863* (Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve).
- *NPRR993*: clarifies gray-boxed language after the concurrent approval of *NPRR902* (ERCOT Critical Energy Infrastructure Information) and *NPRR928* (Cybersecurity Incident Notification).
- *NOGRR196*: clarifies language used by NPRR973-proposed defined terms "generation step-up" and "main power transformer."
- *NOGRR200*: deletes all remaining gray-boxed language associated with *NOGRR025* (Monitoring Programs for QSEs, TSPs and ERCOT).
- *NOGRR202*: removes language regarding the posting timeline for resources' megawatt limits when providing responsive reserve service. The requirement is now outlined in the Other Binding Document procedure for calculating individual resources' limits.
- *NOGRR205*: clarifies gray-boxed language to maintain consistency with revisions adopted from *NOGRR197* (Align Responsive Reserve Manual Deployment Requirements with Current Practice) following the November 2019 incorporation of *NOGRR191* (Related to NPRR939, Modification to Load Resources Providing RRS to Maintain Minimum PRC on Generators During Scarcity Conditions) into the guide. It also corrects an error in ERCOT's administrative comments to NOGRR191 that inadvertently changed the language.
- *PGRR074*: clarifies language used by NPRR973-proposed defined terms "generation step-up" and "main power transformer."
- *PGRR078*: specifies that data related to the regional transmission plan and special planning studies considered protected information may be posted to the market information system's certified area for transmission service providers. The change also includes updated resource asset registration form generator data postings to the system.
- *PGRR080*: aligns the Planning Guide with NERC standard TPL-007-4 (Transmission System Planned Performance for Geomagnetic Disturbance Events) by identifying responsibilities for performing studies needed to complete benchmark and supplemental geomagnetic disturbance vulnerability assessments.
- *RRGRR022*: clarifies language used by NPRR973-proposed defined terms "generation step-up" and "main power transformer."
- *SCR810*: adds logic to ERCOT's energy management system by removing the flag that indicates to the operator that a unit representing a DC tie does not count toward the 2% criterion for activating transmission constraints.
- *VCMRR207*: removes from the manual and its appendix language regarding the validation rules imposed on ERCOT's external telemetry and used in the resource-limit calculator. This maintains consistency between the manual and the protocols by aligning energy storage resource-related provisions with *NPRR986* (BESTF-2 Energy Storage Resource Energy Offer Curves, Pricing, Dispatch and Mitigation) and its provision that storage resources do not have start-up or minimum-energy costs and sets their mitigated offer cap at the systemwide cap. ■

— Tom Kleckner

ISO-NE News

Study: $25 Carbon Price Needed to Meet Goals

$55 to $70/ton Price Needed for 2030

By Rich Heidorn Jr.

New England needs a CO_2 price of $25 to $35/ton by 2025, rising to $55 to $70 by 2030, to meet states' carbon emissions goals, according to a report released Wednesday by the New England Power Generators Association (NEPGA).

The *report*, prepared by the Analysis Group, says carbon pricing is essential to preserving wholesale electric competition and ensuring the least-cost path to meeting the New England states' 2050 goal of reducing economy-wide greenhouse gas emissions by almost 80% compared with 2015 emissions.

While other studies have focused on the 2050 end-state, said NEPGA President Dan Dolan, "this report provides a viable pathway to meet New England's climate change responsibilities by producing needed investments in electricity supplies and enabling electrification in transportation and heating."

A multisector carbon price is essential to the "deep and continuous investments" needed to electrify transportation and heating and build the power system infrastructure to support the transition, the report says. "Without a multisector approach, the financial signal for electrification in transportation or residential heating would be undermined because CO_2 emissions have only been valued in the electricity sector," it says.

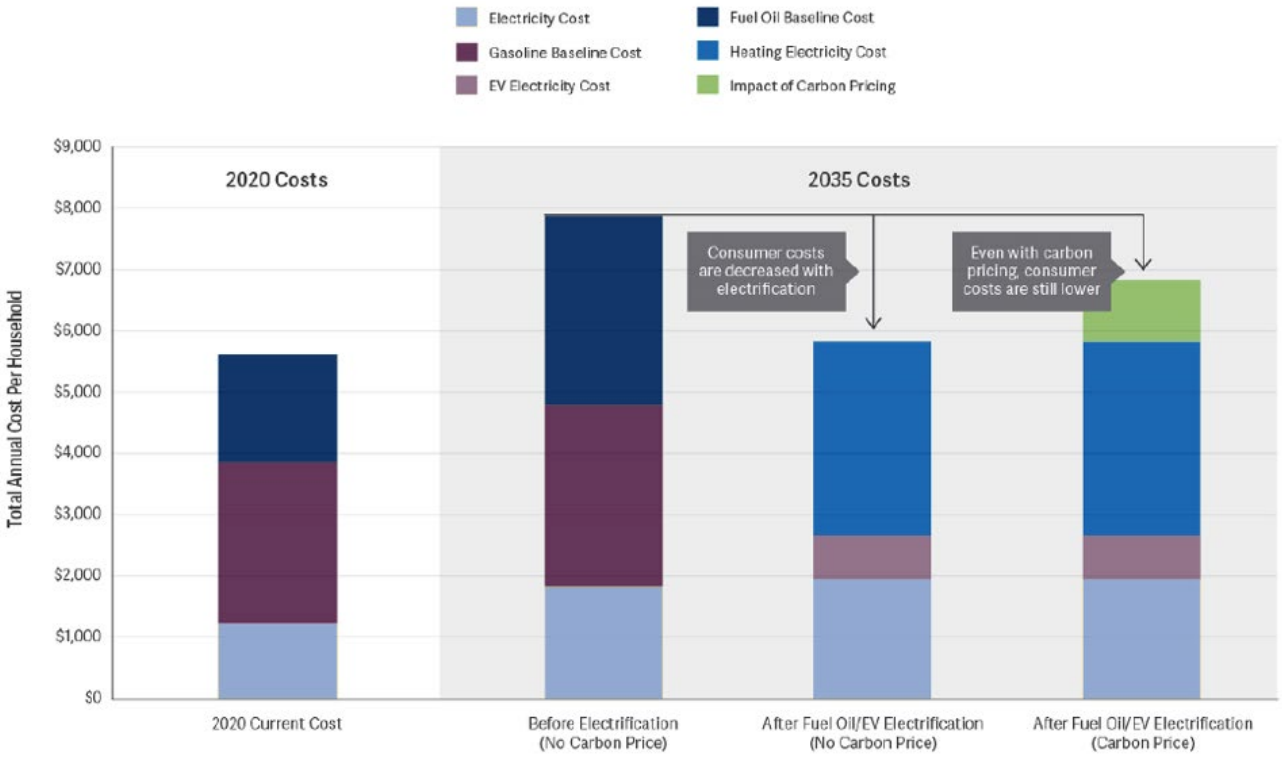
The study employed production cost modeling to determine the carbon prices needed in 2025, 2030 and 2035 to ensure "revenue sufficiency" for the resources required to meet GHG reductions without state or federal procurement mandates or subsidies.

Although the carbon prices calculated are lower than the estimated social cost of carbon, "they would allow for market competition to drive evolution of the region's power system without state-mandated procurement of specific generation resources," the study says.

($MMTCO_2e$).[14]

	Historical Emissions		Standards
	1990	2015	2050
Connecticut	45.3	43.8	9.9
Massachusetts	94.4	76.1	18.9
Maine	21.7	19.1	4.3
New Hampshire	15.8	17.0	3.2
Rhode Island	12.5	11.3	2.5
Vermont	8.6	10.0	1.7
Total	**198.2**	**177.3**	**40.5**

Historical and expected economy-wide greenhouse gas emissions by state | *Analysis Group*



Estimated average annual consumer energy costs for households that adopt electric vehicles and convert home heating system from fuel oil or natural gas to electric heat pumps | *Analysis Group*

ISO-NE News

"The lower range of CO_2 emission prices for 2025 recognizes that certain New England states have already made long-term contractual commitments that provide the financial support needed for various zero-emission resources to be brought into service or remain operational."

The volume of zero-emission resources needed by 2030 and 2035 will increase the frequency of zero-price energy hours, putting downward pressure on prices and requiring a higher carbon price for them to remain viable without subsidies, it says.

The study assumed light-duty electric vehicle penetration of 25% in 2025, 60% in 2030 and 90% in 2035. Similarly, it assumed 25% of homes heating with oil, propane or natural gas would switch to electric by 2025, rising to 50% by 2030 and 75% in 2035.

Lower Household Prices?

Although a carbon price would increase wholesale power prices, it "would not drive up consumer costs materially if states choose to rebate carbon revenues," the study says.

It projects that average residential household energy costs would actually decline by 2035 under electrification.

Without the transition, the study posits annual household energy costs will rise from less than $6,000 currently to almost $8,000 by 2035. Costs would be less than $7,000 with electrification and a carbon price, it said.

Electrification of the transportation sector would be the biggest source of GHG reductions. While residential heating electrification would produce only "modest contributions" to GHG cuts, it would turn ISO-NE from a summer-to a winter-peaking region by 2030.

The study also notes the increasing need for flexible electric sector resources to respond to increased hourly net load variability. More variable renewable resources and the addition of EV and heating loads would increase average hourly ramping requirements to more than 15,000 MW at times in winter, it says.

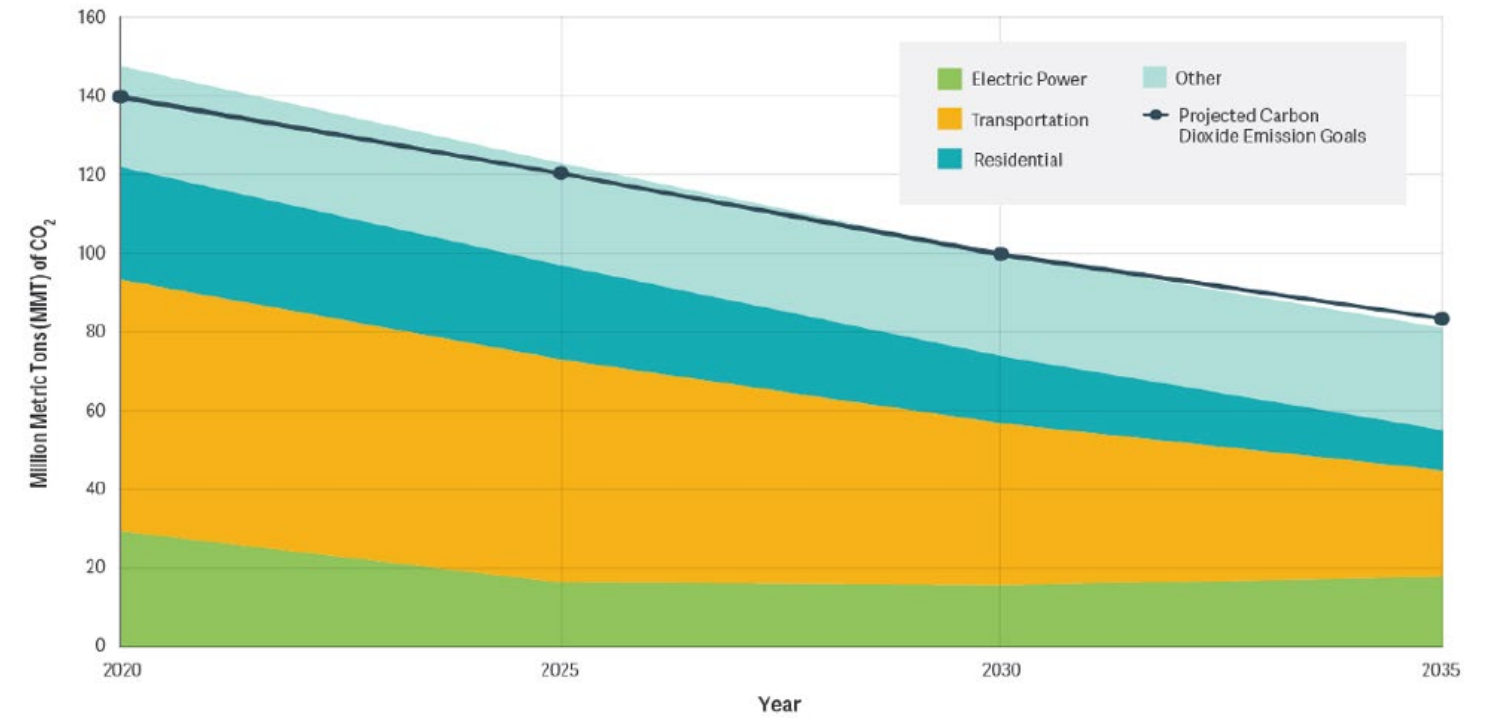
"Even assuming a significant quantity of technologically feasible energy storage resources, the availability of existing fossil fuel generators will be vital over at least the next one to two decades" for ISO-NE to manage the change in load shape and growth in daily ramping needs, it says.

Competitive markets with efficient carbon pricing could save consumers $100 million to $300 million ($2020) between 2026 and 2035 compared with reliance on utility-administered resource procurements.

A carbon price would allow technology-neutral competition; reduce reliance on out-of-market contracts that lock in long-term costs; ensure financing in the absence of long-term contracts; increase incentives for developing new supply-side and demand-side technologies; and encourage consumer use of demand management, the study says.

"It is obvious that establishing enhanced carbon pricing in electric energy markets is not an easy path to take from political and regulatory perspectives," it says. "Yet pursuing these objectives through state-mandated programs and procurements will almost certainly achieve the results imperfectly, and at costs in excess of what would result through efficient carbon pricing. ...

"The absence of an effective carbon-pricing mechanism is a fundamental challenge to continued reliance on competitive markets," it says, calling the Regional Greenhouse Gas Initiative insufficient. "Absent adoption of a carbon price in energy markets, the pace and magnitude of additions of out-of-market, procurement-based resources will likely undermine the continued relevance of wholesale markets in New England as a vehicle for resource development and investment. ... Carbon pricing in energy markets is not an easy path to take, but it may be the only one that can preserve the operation of competition for the benefit of consumers." ■



Projected CO_2 emissions changes by sector under high electrification | *Analysis Group*

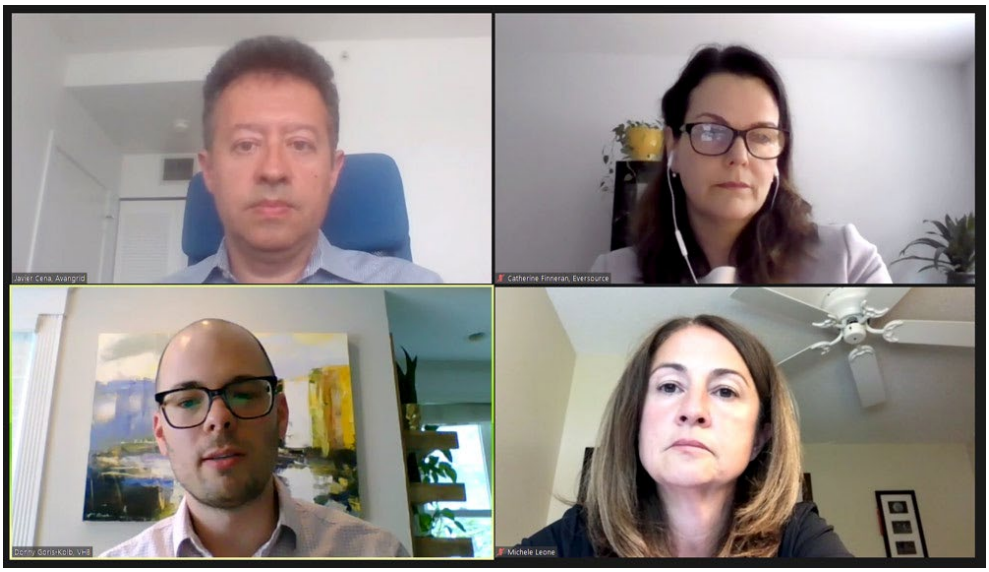
ISO-NE News

NE Utilities Lay out Strategies for Net-zero Emissions

By Michael Brooks

Representatives of three of the dominant utilities in New England on Wednesday briefed Northeast Energy and Commerce Association members about their companies' aggressive decarbonization efforts, suggesting that many other utilities will need to step up their games to reach net-zero emissions by 2050 — the year by which climate experts say the world must stop emitting carbon entirely or find some way to remove it from the atmosphere to prevent catastrophic environmental changes.

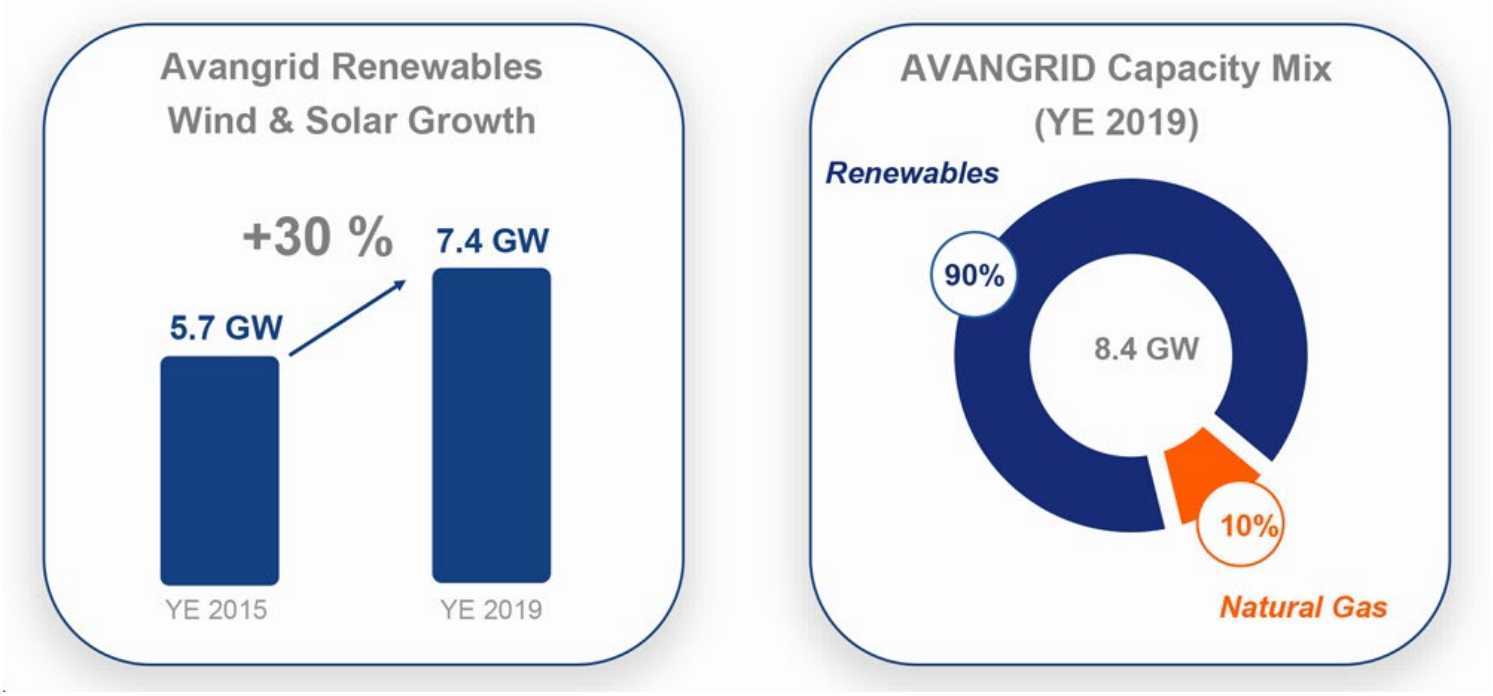
Officials from Avangrid, National Grid and Eversource Energy spent most of their presentations triumphantly pointing to the progress they have made toward their decarbonization goals. The strategies laid out by the officials ran the familiar gamut: aggressive investment in renewable resources, upgrading the transmission system to make it more efficient and co-locating new renewables with storage.



Clockwise from top left: Javier Ceña, Avangrid; Catherine Finneran, Eversource; Michele Leone, National Grid; and VHB Senior Environmental and Sustainability Planner Donny Goris-Kolb, who moderated the discussion. | *NECA*

Driven by legislation passed by states in their service territories, the utilities are indeed well on their way to reaching their targets — for now. National Grid last year, for example, *upped* its goal from an 80% reduction by 2050 from 1990 levels to net-zero emissions by then. Its also increased its interim goals, having already achieved its previously 70%-by-2030 target this year; it's now targeting 80% by 2030.

Avangrid's generation mix is made up almost entirely of wind energy, with 7.4 GW of onshore resources in operation, and another 9.6 GW in development, both on- and offshore. It expects to be carbon-neutral by the end of 2035 — the year its last remaining fossil fuel plant, the Klamath Cogeneration Project in Oregon, will reach the end of its useful life.

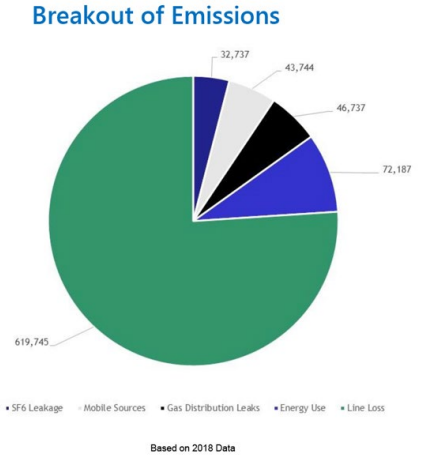


| *Avangrid*

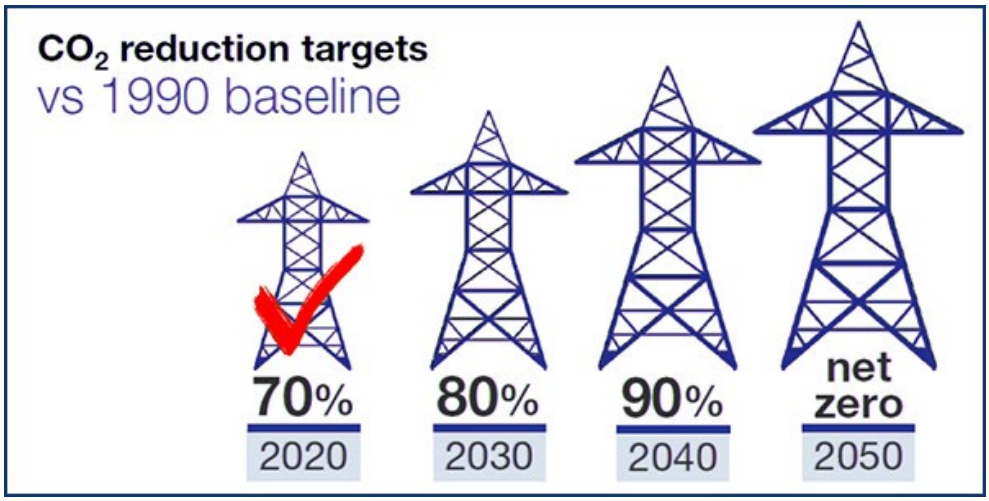
ISO-NE News

But the speakers cautioned that these strategies will get utilities only so far in reaching net-zero emissions by 2050. Nascent technology such as long-duration energy storage, carbon capture and sequestration, and renewable natural gas will be needed not just to offset emissions but to balance the intermittency of renewable resources, they said.

"High penetrations of renewables are going to need some truly flexible power plants to balance them ... which means, for many utilities, natural gas," said Javier Ceña, Avangrid's executive director of sustainability. "So the electric sector might need to rely on carbon capture or carbon-free fuels, like green natural gas or green hydrogen, to reach carbon neutrality by 2050."



Eversource's Catherine Finneran said that line losses actually account for most of the company's emissions and that it is focused on replacing aging transmission infrastructure as part of its decarbonization strategy. | *Eversource*



Having achieved its 70% emissions-reduction goal 10 years earlier than its original target, National Grid last year upped its goals. | *National Grid*

He pointed to Avangrid parent company Iberdrola's demonstration *project* in Puertollano, Spain, that will use a combination of solar and electric storage to produce hydrogen.

National Grid is also in the early stages of developing a program to counter emissions. "As much as our primary focus is to reduce our emissions, we do believe that we will have to do some offsetting in 2050," said Michele Leone, director of sustainability and environment. "So right now we're looking to develop a program ... looking at local partnerships, looking at co-benefits of various offsetting options."

Eversource has perhaps one of the most aggressive targets in the U.S.: carbon neutrality by 2030. Its strategy is to first reduce its own greenhouse gas emissions "to the maximum extent possible," according to Catherine Finneran, vice president of sustainability and environmental affairs. "And then ... we'll offset those emissions, whether through the purchase of offsets or the development of initiatives that produce the offsets."

Both National Grid and Eversource said they're also focusing on reducing leakages of methane from their natural gas pipelines and of sulfur hexafluoride (SF_6) — an extremely potent greenhouse gas rarely mentioned compared to carbon dioxide and methane — which is used in switchgear as an insulator.

SF_6 "might look like a small amount of our footprint, but it is a very big focus for us," Finneran said. The company is working with its suppliers to phase in SF_6-free equipment over the next five years. The challenge, however, is that such equipment is only available for lower-voltage equipment, "and we really need it also at higher voltages as well," she said. ■

ISO-NE News

NEPOOL Participants Committee Briefs

EMM Recommends Market Changes in New England

ISO-NE External Market Monitor David Patton delivered highlights from his 2019 *assessment* of the RTO, comparing its markets with others in the Eastern Interconnection and making several recommendations.

Patton, president of Potomac Economics, related concerns about the current Forward Capacity Market and plugged the benefits of a prompt capacity in the context of improving coordinated transaction scheduling with NYISO.

"We think the pros of a prompt capacity market outweigh the cons," Patton told the New England Power Pool Participants Committee on June 23. "In other words, we tend to think prompt capacity markets perform better than forward capacity markets, and the large demand forecast errors that have occurred in New England highlights one of the many concerns of a forward capacity market."

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

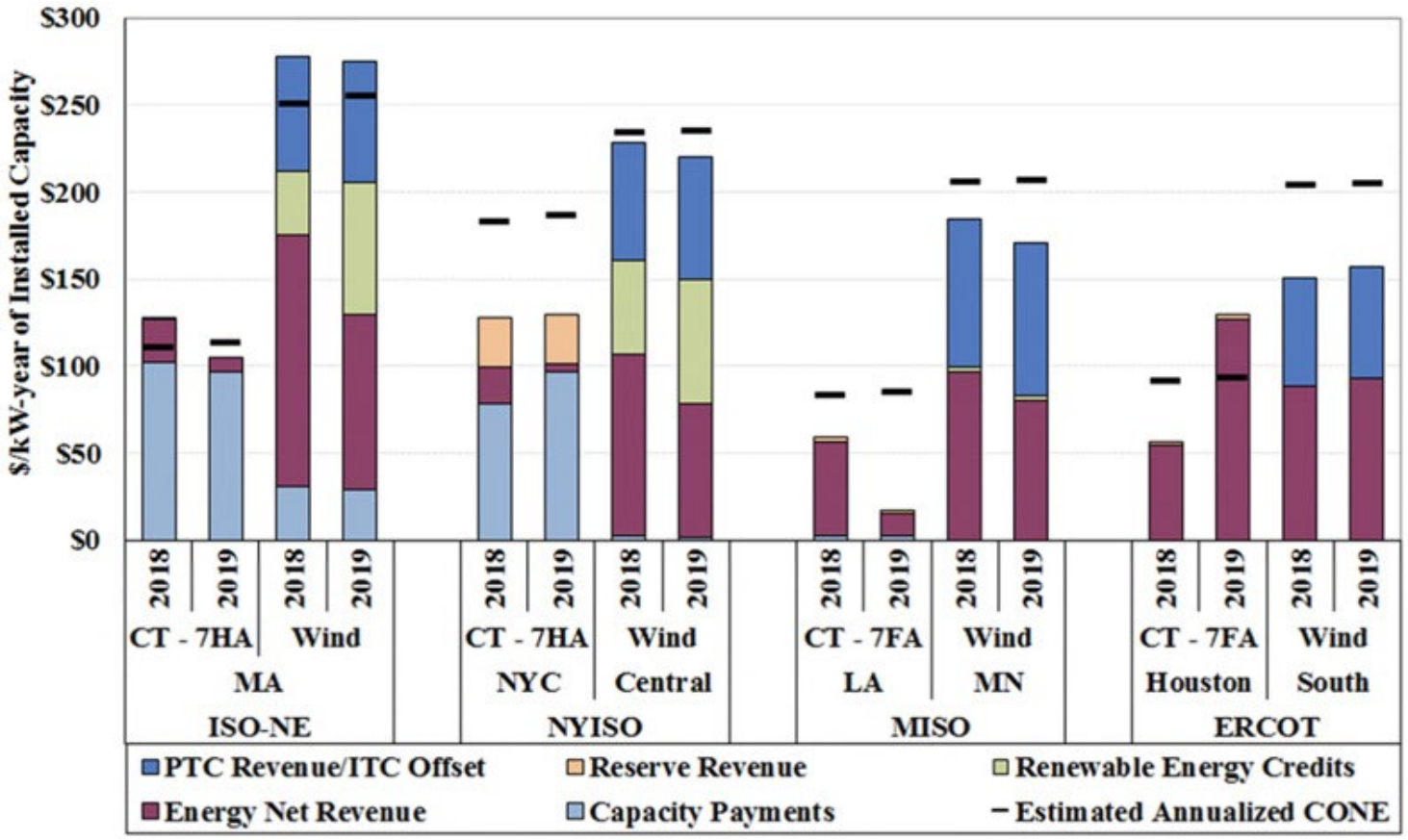
However, he did not recommend eliminating the FCM because the benefits of doing so do not clearly outweigh the market disruptions it would cause. But he did recommend that ISO-NE replace the descending clock auction with a sealed-bid auction to improve competition in the Forward Capacity Auction.

Patton also recommended improving the minimum offer price rule by: eliminating performance payment eligibility for units subject to the MOPR; capping the minimum offer price at the net cost of new entry; and exempting competitive private investment from the MOPR.

A comparison of net revenue across various regional electricity markets showed that a well functioning wholesale market helps establish transparent and efficient price signals, which in turn influence the locations and technologies of new projects, according to the EMM's report.

In New England, net revenues have been close to the levelized new entry costs for combustion turbines, but this will not continue in the future as capacity prices fall over the next few years, the report said. With tax credits and renewable entry credits, the markets are providing more than sufficient revenues for wind resources. Wholesale market revenues will continue to play a key role in motivating entry of flexible units that help integrate policy resources and prompt the retirement of inflexible units.

The EMM also recommended the RTO modify allocation of "economic" net commitment period compensation (NCPC) charges — the pay-



Net revenue comparison across markets | *Potomac Economics*

ISO-NE News

ment made to market participants that don't recover their effective offer costs — to align it with cost causation, and pursue improvements to the price forecasting that is the basis for CTS with NYISO.

An uplift rate of $2 to $3/MWh over the past three years generates millions of dollars in day-ahead NCPC payments, but "the shocking number is the number of hours, almost half the hours of the year, when commitments are being made to supply spinning reserves," Patton said.

"This signifies that both our prices and our compensation in the day-ahead is not very efficient when it comes to the types of units that are supplying the spinning reserve product," he said. "It also tends to undermine the energy price because, to the extent that costs are being incurred to meet the spinning reserve requirements, those costs should be reflected in energy prices." However, Patton indicated that the RTO's Energy Security Improvements (ESI) initiative will address these concerns.

When asked about how recent reductions in load forecasts should be factored into the capacity market requirements, Patton said that "the general principle is that you should do everything you can to make your installed capacity reserves forecasts as accurate as possible, recognizing that there are Tariff requirements and tradeoffs where the ISO has to publish what the requirements are in advance of the auction so that people can ... offer into the auction."

Further recommendations are to modify the performance payment rate to rise with the reserve shortage level and not implement the remaining planned increase in the payment rate; and consider modifying the capacity compensation of energy-limited resources to be consistent with their reliability value.

The Monitor also recommended that the RTO require the use of the lowest-cost fuel or configuration for multiunit generators when they are committed for local reliability.

BPS Reliability Perspectives for 2050

NERC CEO Jim Robb | *ISO-NE*

NERC CEO Jim Robb gave the PC a look at various bulk power system reliability perspectives at midcentury, with key issues being the timing of technology development and deployment (especially batteries), the pace of deep electrification and the regulatory treatment of natural gas.

"The one challenge our industry has is that we're enormously reactive," Robb said. "We are great at responding to an event and figuring out what went wrong and changing it, but we are not great at heading events off before they happen, because it's hard to motivate people to make hard choices when they don't feel them very present."

Bruce Ho of the Natural Resources Defense Council referred to the need for increasing system flexibility in which load follows generation — rather than just generation following load — as the country gradually moves to a fully decarbonized grid that relies on variable energy resources like wind and solar.

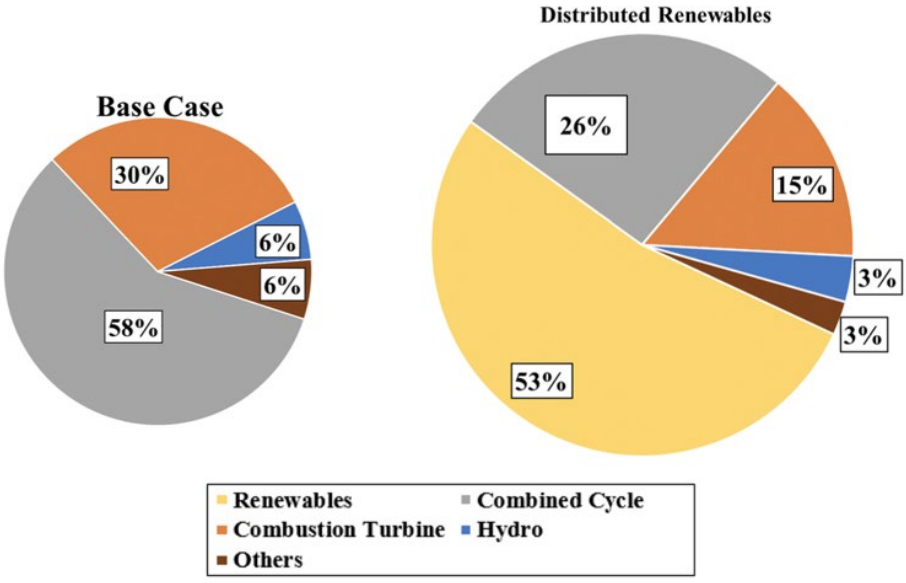
"I'm curious what you see as the role in the other direction, with more dynamic loads that follow supply," Ho said, citing the importance of demand response. "What role do you see on the demand side, and do you have any thoughts on how markets and reliability standards might need to adapt to incorporate and compensate that dynamic load?"

"We need to rethink so many things, because I actually have a bias of thinking of the electric system serving load," Robb said. "And you're right; as Mark Lauby says — who's our chief engineer and the smartest technical guy I know on this stuff — that concept is increasingly flawed."

Planners need to expand their thinking about the grid beyond a linear relationship between the bulk power system, the distribution system and end users, he said. It would be wrong to describe them as being "integrated," Robb said.

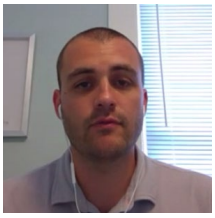
"Really, they're all interdependent," he said. "When I talk about the new models, the new operating paradigms, I think those issues need to be brought in as much as anything else. Demand response can play a really important role, but will it be there on the fourth day of the heat wave? I have a little bit of a [former PJM CEO] Terry Boston view of the world in that I like iron in the ground, because I know I can do something with it."

Robb cited cybersecurity as a constant issue and said he does not like the term "Internet of Things," preferring to think of it as the "Internet of Threats."



Distribution of outage risk by technology type | *Potomac Economics*

Investing in the Future



Scott Kushner, John Hancock | *ISO-NE*

Scott Kushner, managing director of Boston-based John Hancock Infrastructure Investments, discussed how he and his team decide where to invest in the electric power industry and how changing public policy affects such decisions.

ISO-NE News

Of the firm's $30 billion in assets under management, approximately 30% is invested in private equity investments, while the remaining 70% is in investment-grade, long-term, fixed-income debt products, Kushner said.

"We lend to utilities; we've lent to projects, power plants of all technologies, all fuel sources; but certainly lately renewables has become a very big piece of what we're looking at on both the debt and equity side," Kushner said. "One of the main drivers of that, if you look at what an insurance company likes to invest in, is the lower-risk stuff, the stuff with longer-term contracts."

On lowering the cost of capital, James Daly, vice president of energy supply at Eversource Energy, asked whether Kushner preferred programs with more revenue certainty or those dependent on merchant revenues.

"It certainly helps from an institutional investor standpoint," Kushner said. "I would say that *SREC 1* and SREC 2 [solar renewable energy credits] in Massachusetts worked really well, but certainly when we're looking at the cost of capital for the *SMART* [Solar Massachusetts Renewable Target] program, which has the longer-term feed-in tariff like contracts, the cost of capital has come down even lower."

Whether because of highly structured state programs or just the evolution of time and more investors starting to get comfortable in the clean energy space, "certainly the longer the contract, the more certainty in it, there's no denying that will lower the cost of capital," Kushner said.

"It seems that the capacity market in New England, with the seven-year lock rate available for new resources, is able to provide sufficient revenue certainty and risk reduction to make financing terms attractive for gas generation, but it doesn't have the comparable impact for financing of renewable generation because those resources get the majority of their revenue from the energy market, which has no similar long-term certainty," said Abigail Krich, president of Boreas Renewables.

Frank Felder, Rutgers | *ISO-NE*

"While state solicitations for long-term contracts and programs like SMART are filling in that gap to provide comparable revenue certainty to renewable resources, if the wholesale market were modified to be able to supply a similar level of revenue certainty to renewable resources, would those long-term contracts and policy commitments for renewables still be needed in order to be able to finance them?" Krich said.

There's a place for both gas-fired generation and renewables in the market, Kushner said.

"If the market were to shift from these longer-term contracts to something like the capacity market for fossil fuels, which gives these projects price certainty for maybe five to seven years, the projects absolutely will get financed," Kushner said. "It just depends on who's going to actually finance them and what the ultimate cost of capital is."

Problem Trio

Rutgers University professor Frank Felder, who teaches electricity policy and market structures, *presented* a thesis posing three types of problems that market operators and public officials must address: political economy, economic/regulatory and engineering.

"They are really three subsets of the same problem," said Felder, director of the Rutgers Energy Institute and the school's Center for Energy, Economic and Environmental Policy.

Deep decarbonization is a political economy problem because it concerns jobs, costs and economic policy, which interact with the economic and regulatory problem, he said.

"Whether an entity is regulated, or in a market environment, or in an integrated utility environment, there are economic and regulatory incentives that shape the decision-making, and in particular with long-term loan capital assets, you have a variety of problems, such as asymmetric information," Felder said.

For example, an offshore wind developer knows more about the cost structure of a power purchase agreement than the regulator signing off on the deal, he said.

Engineering comprises both optimization and system-control problems, Felder said.

Political, economic and reliability difficulties are likely to arise unless these three types of problems are addressed in an integrated and consistent manner, he said.

"Massachusetts is really committed to trying to find a market-based solution to integrate clean energy," said Matthew Nelson, chair of the state's Department of Public Utilities. "We know that's not going to be easy.

"Massachusetts has been very supportive of carbon pricing, so we've supported the Regional Greenhouse Gas Initiative. We have initiatives [that encompass more than] energy, like our state-specific Clean Energy Standard, and the Transportation Climate Initiative, but we're not so interested in a FERC-jurisdictional carbon pricing — that concerns us," Nelson said.

Massachusetts wants to ensure that a carbon price brings clean resources online and that it works with existing state policies, he said. Meanwhile, "other states in New England are in very different places on this one as well."

"Where we're all aligned, at least on carbon, is we don't have any interest in a federal-based carbon price that would prevent states from achieving their individual goals," Nelson said. "How is the price set? How is it priced accurately? Those are big, fundamental questions that bother individuals." (See *Study: $25 Carbon Price Needed to Meet Goals*.)

Speaking to *RTO Insider* after the meeting, Nelson said, "Specifically here, what I think is important is who is setting the price and that process, because obviously that's a big decision and will influence the outcome. I feel that's a question we need to answer before states would be supportive."

Some states don't have clean energy targets and don't think that increasing the price of carbon is actually what they want to achieve, he said.

"At this time, I just don't think that a new carbon price adder outside of RGGI is politically feasible for all six states," Nelson said. "But we're not scared to talk about the data, what that data achieves, where the price is set. I think we have to have the conversation around what the numbers are and what we're paying through different processes, to understand the different policy decisions we're making.

"We have aggressive clean energy targets in Massachusetts," he said. "I know that we're going to need more clean energy to come online, and most of the need will be met through load growth through some of our policies around decarbonization of transportation, of buildings. And continued out-of-market contracts still have some inherent drawbacks, especially in the long-term scale we're talking about." ■

— Michael Kuser

MISO News

Study Foresees MISO Solar Eclipsing Wind

By Amanda Durish Cook

MISO's southern and central regions could surpass the RTO's wind-heavy northern reaches as the biggest producer of renewable energy as solar generation grows in popularity, new study results indicate.

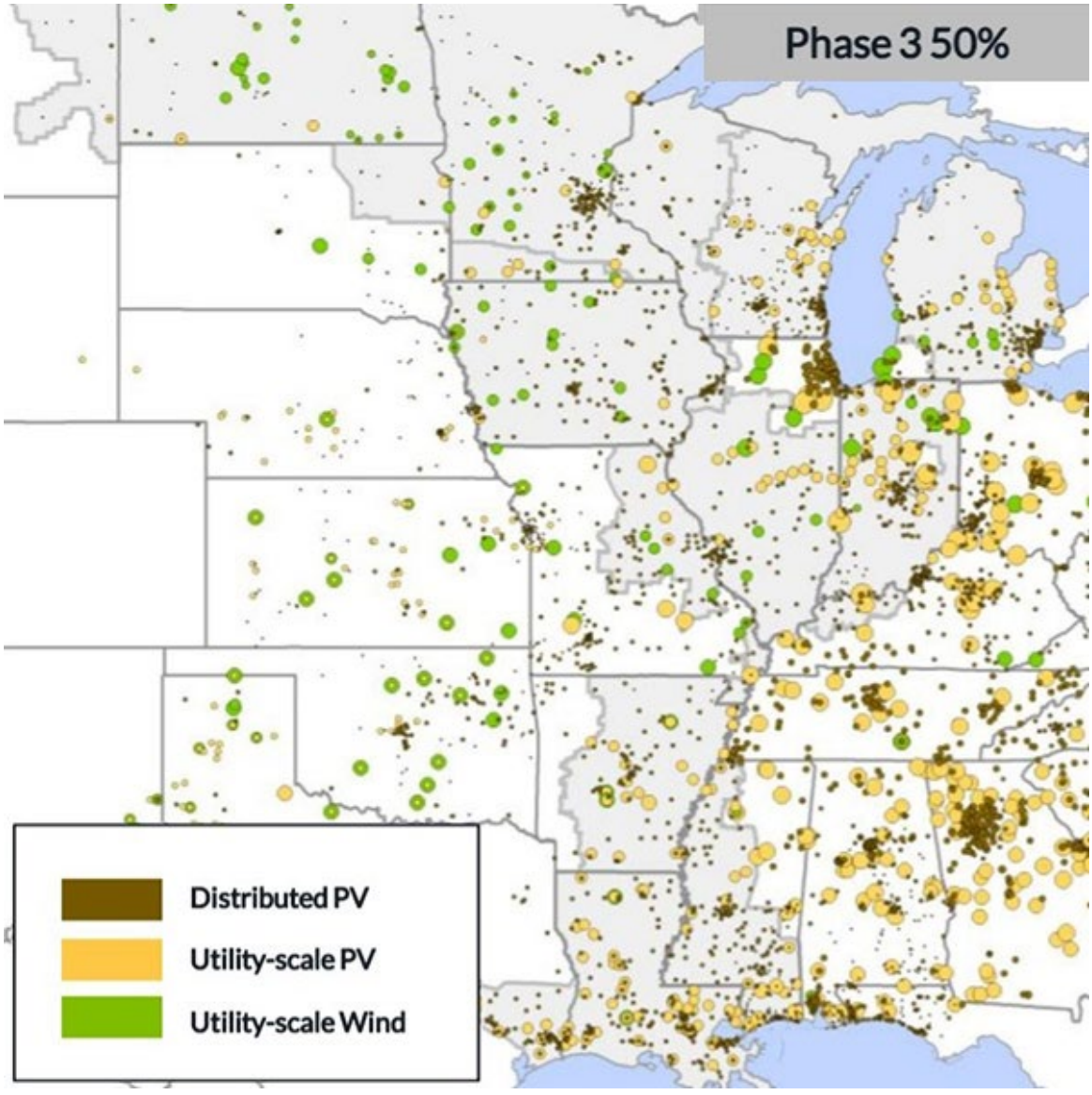
The findings come out of MISO's ongoing Renewable Integration Impact *Assessment* (RIIA), which most recently focused on where new resources could be located when renewables rise to 50% of the RTO's resource mix. It found distributed and utility-scale solar installations would proliferate in Michigan and Indiana and the footprint's southern states, while the wind buildout that has so far dominated the North planning region winds down.

"Some of the heavy wind that we were seeing in Minnesota, North Dakota and even Iowa, we're starting to see a shift," James Okullo, MISO policy studies engineer, told stakeholders during a teleconference Friday.

The RIIA results are based on trends in MISO's interconnection queue and load ratios in local resource zones. The Southern Alliance for Clean Energy recently *predicted* the U.S. Southeast could contain 25 GW of solar capacity by 2023.

Okullo said MISO has generally found that grid needs rise sharply beyond a 30% renewable penetration. Previous results of RIIA have concluded that to operate with a 50% renewables mix, MISO must boost reserve requirements and demand-side management, dramatically increase transmission (including HVDC) and add more technology to lines, including synchronous condensers and transformers. (See *MISO Renewable Study Shows More Tx, Tech Needed*.)

MISO has been undertaking the study since 2017, which used actual peak load levels at the time and a 2022 power flow model to draw conclusions. The RTO has not yet modeled strategic energy storage additions in addition to the growing renewable share, and Okullo said it would have new RIIA results by August projecting how much energy storage might be needed to help ease the transition.



Possible resource additions at 50% renewables | *MISO*

For now, MISO's study projects an increasing risk to serving load outside of summer as solar generation gains momentum. A large solar fleet staves off the usual early evening daily peak as the sun still shines, compressing risk to a shorter and steeper time period later in the evening, the RTO said.

The Union of Concerned Scientists' Sam Gomberg last month said that MISO might be biasing the presentation of RIIA results in terms of what the system could not do rather than what it could. After the RTO presented its last RIIA results last November, many stakeholders walked away with the view it couldn't possibly operate with more than 40% renewable penetration because of complexity, he said.

"I would encourage you to think hard about the takeaways you communicate and the message you deliver," Gomberg told staff during a Planning Advisory Committee teleconference May 13. ■

MISO News

MISO Planning Advisory Committee Briefs

DER Data Requirement Becomes Request for LSEs

MISO has temporarily backed off requiring load-serving entities to provide the location and capacity values of distributed energy resources for its planning models.

Planning Modeling Manager Amanda Schiro told the Planning Advisory Committee on Wednesday that the requirement for LSEs to provide counts of inverter-based DERs on distribution systems has been *downgraded* to a request for 2021.

Schiro said this year's request is only intended to allow MISO to get a better handle on DER siting. She said the RTO is only in a "data-gathering mode" to possibly introduce future modeling improvements that better capture DERs.

MISO wants LSEs to provide more explicit DER estimates for transmission planning models by 2022.

DERs are registered in the capacity market but not represented in the RTO's planning models, Schiro said. She said DER integration into reliability planning and operations and market systems will soon necessitate a modeling change.

Summer peak load continues to drop slightly every year, and DERs could play a role in that, Schiro said.

"We want to plan for the situation we're going to find ourselves in," she said.

For now, MISO needs more information to decide how to represent DER in modeling, Director of Planning Jeff Webb said.

"We're trying to just get an understanding of what's out there," he said, agreeing with stakeholders that MISO must engage in more discussion with LSEs before it adopts a new approach for better estimating DER in planning models.

Some LSE representatives have expressed skepticism over MISO's DER modeling goals.

WEC Energy Group's Chris Plante said many LSEs already include in their forecasts any DERs they have insights into. He also said it might be impossible for MISO to locate all DERs.

"In some cases, it might not be practical to model some DERs because some might be behind the customers' meter, and we have nothing to do with it," Plante said.

Rooftop solar in Indianapolis | © *RTO Insider*

MTEP Transfers Under Study

MISO has defined the transmission transfers it will study in its 2020 Transmission Expansion Plan (MTEP 20) to determine the system's capability for handling various transfer scenarios.

The RTO is *studying* nine transfers under the MTEP 20 voltage stability analysis, which seeks to find future "soft spots" that might cause contingencies on the system. Three of the transfer scenarios will focus on transfer paths from Minnesota to areas in Wisconsin and Illinois, while two others focus on exports into the Downstream of Gypsy area near New Orleans from other Entergy territories.

The analysis also includes:

- Minnesota and North Dakota's exports into Manitoba Hydro territory;
- Indiana and southern Michigan's exports to the St. Louis area;
- exports from Iowa into the MISO Central planning region of Indiana, Illinois, western Kentucky and eastern Missouri; and
- MISO South to the West of the Atchafalaya Basin load pocket straddling Texas and Louisiana.

Additionally, MISO is *studying* five transfers under its NERC-required transfer study, used to determine the ability of the MISO system to handle possible power transfers across the footprint:

- MISO's South Region to SPP;
- Ontario's Independent Electricity System Operator to MISO's East planning region;
- MISO Central to the North planning regions in both directions; and
- PJM's Northern Illinois territory to the rest of its footprint east of Indiana.

Nearly all the transfers were chosen based on heavy historical usage; however, the PJM transfer was selected because of an influx of wind generation additions in the area by 2025.

At the end of last month, MTEP 20 contained 510 proposed projects at a combined $4.06 billion. (See *Price Tag Rising for MTEP 20*.) Those figures will remain fluid as MISO finalizes the transmission package over the next three months.

MTEP 20 is also on a shorter-than-usual timeline this year.

MISO announced earlier this year that it will revise the MTEP 20 schedule to allow the Board of Directors' System Planning Committee an additional month to review the transmission package prior to the full board vote in early December. That means the PAC will review, then vote on, whether to recommend the draft MTEP 20 report about a month earlier than usual, in September instead of October. (See "MTEP 20 Schedule Change," *Northern Focus for MTEP 20*.)

PAC Chair Cynthia Crane has said the truncated MTEP timeline caused "some consternation" among stakeholders. "As much as everyone wants to give the board extra time to review, it's going to take a month out of the process to form the MTEP," Crane reported to the MISO Steering Committee in February. ■

— Amanda Durish Cook

MISO News

IMM Issues 5 Recs in MISO State of the Market Report

By Amanda Durish Cook

MISO's Independent Market Monitor issued five new recommendations in its annual State of the Market report released Wednesday, focusing on the RTO's management of flows across its seams, dynamic transmission line ratings and whether energy efficiency should be considered a capacity resource.

But IMM David Patton also used presentation time before the MISO Board of Directors' Markets Committee to issue a warning on the deteriorating condition of the RTO's reserve margins.

MISO Executive Director of Market Strategy and Design Scott Wright said the new recommendations this year concentrate on seams and efficient use of the transmission system. Three recommendations offer advice on how to manage flows between neighboring RTOs, where the Monitor suggests:

- Using new testing criteria for defining market-to-market constraints. Patton said the rules for determining flowgates have not been overhauled since 2004 and could use an update that places more emphasis on how much available flow relief a non-monitoring RTO can provide.
- Improving the relief request software used in market-to-market coordination. Patton said MISO's current relief request software does not always request enough relief from the non-monitoring RTO because it doesn't consider shadow price differences between the RTOs.
- Clearing coordinated transaction scheduling transactions with PJM every five minutes based on the most recent five-minute prices, not forecasts. The Monitor said "persistent forecasting errors by MISO and PJM have likely hindered" use of coordinated transaction scheduling. Instead, Patton said the most recent five-minute prices are a more accurate forecast of the prices over the next five minutes.

MISO IMM David Patton | © *RTO Insider*

Patton's two other recommendations include MISO developing the capabilities to apply dynamic transmission line ratings from transmission owners and disqualifying all energy efficiency resources from the capacity auction.

Most MISO TOs don't adjust line ratings to reflect ambient temperatures and wind speeds, Patton said. He said a "broad adoption" of ambient-adjusted ratings could have reduced congestion costs by $150 million in 2018 and 2019.

Patton also said if all TOs provided short-term emergency ratings, which tend to be about 10% higher than normal ratings, MISO might have saved as much as $114 million in congestion over the past two years.

"The ratings transmission owners provide tend to be overly conservative," Patton said. "If you calculate how much we could save by rating transmission lines more efficiently, it would be something like $265 million."

Further, Patton said more efficient line ratings on just the top 25 constraints could achieve two-thirds of that estimated savings alone.

"Hopefully over the next year, we'll see some progress," he said, adding that effectively managing congestion can save MISO more than developing a new, big-ticket market product.

Patton also said allowing energy efficiency resources to offer into the MISO Planning Resource Auction (PRA) makes little sense.

"Funneling an additional subsidy to pay for LED lightbulbs is an inefficiency," Patton said, adding that capacity payments for energy efficiencies don't make sense because entities with installed energy efficiency are already saving on retail bills.

He also said capacity payments for energy efficiency owners further offset the bills that contain, ironically, the cost of serving them, including energy, ancillary services, and capacity, transmission and distribution costs.

"When they purchase energy-efficient equipment, the electric bill savings include all of these elements. There's just an array of problems," Patton said of energy efficiency receiving funding through MISO's capacity market. "The quantities are growing rapidly and in key tight locations like Michigan."

MISO News

Last year, Patton produced six new market recommendations as part of his 2018 report, among them clarifying the criteria for calling emergencies, procuring operating reserves on the Midwest-to-South regional transfer limit and lowering the generator shift factor cutoff for transmission constraints with limited relief. (See *MISO Monitor Poses 6 New Market Recommendations*.) MISO has yet to issue proposals on any of the 2018 recommendations, though it is working on new capacity accreditation requirements that could address two of the six recommendations. The RTO also discussed possible improvements to the logging and documenting of emergency procedures with the Monitor last year.

Markets Competitive, but Trouble Brewing

Patton also reported that offers into the MISO markets throughout 2019 were highly competitive.

"The prices were about as competitive as they could be. The MISO markets always performed very competitively," Patton told board members.

Real-time prices for the year averaged just $26/MWh in the footprint, driven by cheap natural gas and a 2% decrease in average load, while a cooler year overall brought lower demand, he said.

By the IMM's count, 3.3 GW of resources retired in MISO last year. Of those megawatts, almost 90% were coal generation. Patton said more than 4.5 GW of new capacity entered MISO over the same time, including nearly 2 GW of natural gas capacity in MISO South and more than 2 GW of less dependable nameplate wind capacity.

"Nuclear and coal resources are under a tremendous amount of pressure, mainly because gas prices are so low," Patton said.

Patton predicted a continued gradual loss of coal resources in MISO, making the need for reliable capacity resources more pressing. He said the retirements make MISO's possible rethink of its capacity resource accreditation even more crucial. Capacity accreditation must be doled out according to resource's ability to serve capacity reliably, he said.

"It's likely to be one of the most unpopular proposals among participants, since it'll look like we're taking capacity credits away. It'll be a heavy lift because it'll look hostile — or at least adverse to their interests — to participants," Patton said.

"What's striking about this [report] is the theme of a resource mix in transition," Wright said.

The Monitor also reserved space in the report to decry the continued use of a vertical demand curve and advocate for a sloped demand curve in the PRA.

Save for a high zonal price in Lower Michigan in this year's capacity auction, the PRA produces prices that are "close to zero and generally represent less than 2% of the revenue needed to support investment in new peaking resources," Patton said. "These prices have really hammered the merchant generation and forces them into retirement … or selling capacity outside the footprint."

Addressing its board earlier this month, MISO *said* there was a "lack of assurance that the existing resource adequacy construct will … promote participant investments that ensure sufficient resources are available to meet load in all time periods."

According to MISO's Tariff, the RTO's leadership has 120 days, until Oct. 16, to make a public response to Patton's recommendations. ■

MISO News

Mankato Sale Approved over Public Citizen Concerns

By Amanda Durish Cook

FERC on Wednesday approved the purchase of the Mankato natural gas plant in Minnesota by a specially created subsidiary of Southwest Generation, despite concerns about the company's links to a JPMorgan Chase investment fund (*EC20-54*).

Denver-based Southwest Generation Operating Co. formed subsidiary SWG Minnesota Holdings for the sole purpose of acquiring the 760-MW Mankato Energy Center for $680 million.

Through a series of parent company arrangements, JPMorgan's Infrastructure Investment Fund (IIF) holds 100% of the voting securities of Southwest Generation Operating Co.'s parent company. IIF is controlled by three private owners using a slightly different company name. Those owners also own about 29 MW worth of small generating facilities in MISO.

Consumer interest group Public Citizen had questioned JPMorgan's involvement with the sale, asking the commission to require the company to more clearly explain its involvement with its subsidiary investment fund.

"Determining IIF's affiliation with JPMorgan Chase and Co. in the Mankato transaction is vital for establishing whether the Mankato transaction is in the public interest, as failing to address affiliation threatens harm to competition, rates and regulation," Public Citizen said.

But FERC said the new owners are affiliated with just 0.4% of the generation capacity in MISO, a "*de minimis* amount." The commission declined to require SWG Minnesota Holdings to conduct an analysis to prove no harmful effects on competition.

Mankato Energy Center | *Southern Co.*

The commission also said that "treating J.P. Morgan Investment as an affiliate of SWG Minnesota Holdings would not change the ultimate result of the commission's analysis of the effects of the proposed transaction on competition, rates, regulation or cross-subsidization."

Xcel Energy purchased Mankato from Southern Co. for $650 million in January. The quick turnaround will net the utility $30 million, two-thirds of which it *promised* will be earmarked for corporate giving and COVID-19 relief in its eight-state territory.

Mankato will continue to provide energy to Xcel through long-term contracts. ■

MISO News

MISO Unveils 1st Proposal to Consolidate Tx Planning

By Amanda Durish Cook

MISO last week floated a proposal that would require network upgrades needed by projects in the generator interconnection queue to reach certain voltage and price levels before they could be tested for the economic benefits needed for cost-sharing eligibility.

But renewable proponents argue the plan wouldn't do much for developers facing costly upgrades.

The proposal is a starting point for MISO's effort to coordinate and align studies found in network upgrade planning in the interconnection queue and the RTO's annual Transmission Expansion Plan (MTEP), Senior Manager of Economic Planning Neil Shah told stakeholders during a Planning Advisory Committee teleconference Wednesday. (See *Regulators Not Sold on MISO Tx Planning Sync*.)

Under the proposal, a generation project's needed upgrade would need a minimum rating of 230 kV and cost at least $5 million to be eligible for evaluation as a possible market efficiency project (MEP), the same thresholds set out for MEPs in MISO's proposed cost allocation plan, currently awaiting FERC approval. (See *Local Projects Axed from MISO Cost Allocation Refile*.)

MISO is additionally proposing that costs for a network upgrade submitted for economic evaluation can be spread across a group of interconnecting generation projects as long as they are $50,000/MW or higher. However, the projects necessitating the upgrade would need to have already completed the queue and executed a generator interconnection agreement (GIA) before they could be evaluated.

Shah said a GIA execution would help MISO avoid running economic analyses on projects that haven't completed all interconnection studies.

Neil Shah, MISO | © *RTO Insider*

"The benefit of this process is that it allows MISO and stakeholders an opportunity to compile and list all [generator interconnection] projects for economic evaluation rather that doing it on an *ad hoc* basis as interconnection projects come in," Shah said.

He said MISO is aware that the RTO's Environmental and Other Stakeholder Groups sector is critical of the proposal, arguing that it wouldn't give interconnection customers certainty on future cost-sharing as they make their way through the definitive planning phase (DPP) of the queue.

Too Late

Sustainable FERC Project attorney Lauren Azar said the economic evaluation would still come too late for "bona fide" developers saddled with large network upgrades that could show regional economic benefits for others.

"This proposal is not going to solve the problem of generators being scared away by large increases, because by the time a generator interconnection agreement is signed, those customers would have already been scared away by large network upgrade costs," Azar said. "I don't think this scratches the itch of the problem we have before us."

"We're not going to wait until we have signed GIAs in order to get an economic evaluation. … This really doesn't solve the problems. If folks get to a signed GIA, it's likely that they can afford those upgrades," Clean Grid Alliance's Natalie McIntire argued.

But Shah said he didn't think an economic evaluation earlier in the DPP would be feasible. Even if MISO were to figure out the timing issue, it likely wouldn't make a substantial dent in project withdrawals because affected-system studies with neighboring grid operators — which come later in the interconnection process — also reveal high upgrade costs, he said.

Trust Queue Price Signals?

Stakeholders asked how interconnection customers could gain insight into whether their network upgrades could be economically beneficial.

Shah said it would depend on the customers' access to tools and modeling — or by hiring of consultants, if they do not have tools to perform their own economic analysis.

"The interconnection queue is working as designed. We've got too many interconnection projects interconnecting at places where there isn't enough transmission. It's sending that signal to either reinforce the grid or go somewhere with less congestion," WEC Energy Group's Chris Plante argued.

Indiana Utility Regulatory Commission staffer Dave Johnston agreed, saying requests for proposals or power purchase agreements could benefit from inclusion of grid upgrade costs.

"We need a big transmission overlay if a lot of people in the footprint wanted to procure resources of those areas," and that's not happening, Johnston argued.

Azar said that while price signals are appropriate, network upgrades have never been evaluated for economic benefits, even though project developers are being told to build "backbone" transmission projects.

Apex Clean Energy's Richard Seide said the 2017 MISO West network upgrade costs were so egregious that nearly all were canceled, even those projects with PPAs approved by state commissions. Of the 27 generation projects that entered the February 2017 MISO West queue cycle, all but two dropped out, hindered by expensive but necessary transmission upgrades to accommodate the projects that cost tens to hundreds of millions of dollars per project.

More to Come

Shah stressed that the proposal for making interconnection project network upgrades eligible for economic evaluation was just the first step that MISO is considering to align transmission planning processes. He asked stakeholders to consider whether its next step should be changing its annual MTEP model building timeline in order to get more data from the interconnection queue.

Shah added that MISO's goal is to align the two processes and not disturb them — or the FERC-approved Tariff language that governs them — as much as possible.

"I hope that we don't make perfect the enemy of the good," McIntire said, arguing that generator interconnection planning doesn't need to perfectly conform to the timeline of a year and pointing out that even MTEP studies begin prior to the plan's approval year. "We don't need to get too hung up on making this 365 days." ■

NYISO News

Bulk Tx, 115-kV Upgrades Needed for NY '70x30' Goal

BIC Apporves CARIS Report

By Rich Heidorn Jr.

NYISO will need to expand its bulk transmission and some low-voltage lines to meet New York's 2030 climate goals, according to the latest Congestion Assessment and Resource Integration *Study* (CARIS).

Jason Frasier, the ISO's new manager of economic planning, *presented* the study to the Business Issues Committee on Wednesday, which recommended it be approved by the Management Committee.

Business as Usual

The report, the first phase of the ISO's two-phase economic planning process, contains a "business as usual" base case that includes only incremental resource changes based on known planned projects with a high degree of certainty. It simulated hourly grid operations from 2019 through 2028, based on the 2019-2028 Comprehensive Reliability Plan, which includes the Western New York and AC Transmission Public Policy Transmission Projects scheduled to enter service on June 1, 2022, and Dec. 31, 2023, respectively.

The model simulated how investments in transmission, generation, demand response and energy efficiency would impact congestion in the three most congested transmission corridors: Central East, Central East-Knickerbocker and Volney-Scriba.

As in past studies, the base case found "limited opportunities for transmission buildout based solely on production-cost reductions" reflecting the current "generation-rich" system, the ISO said.

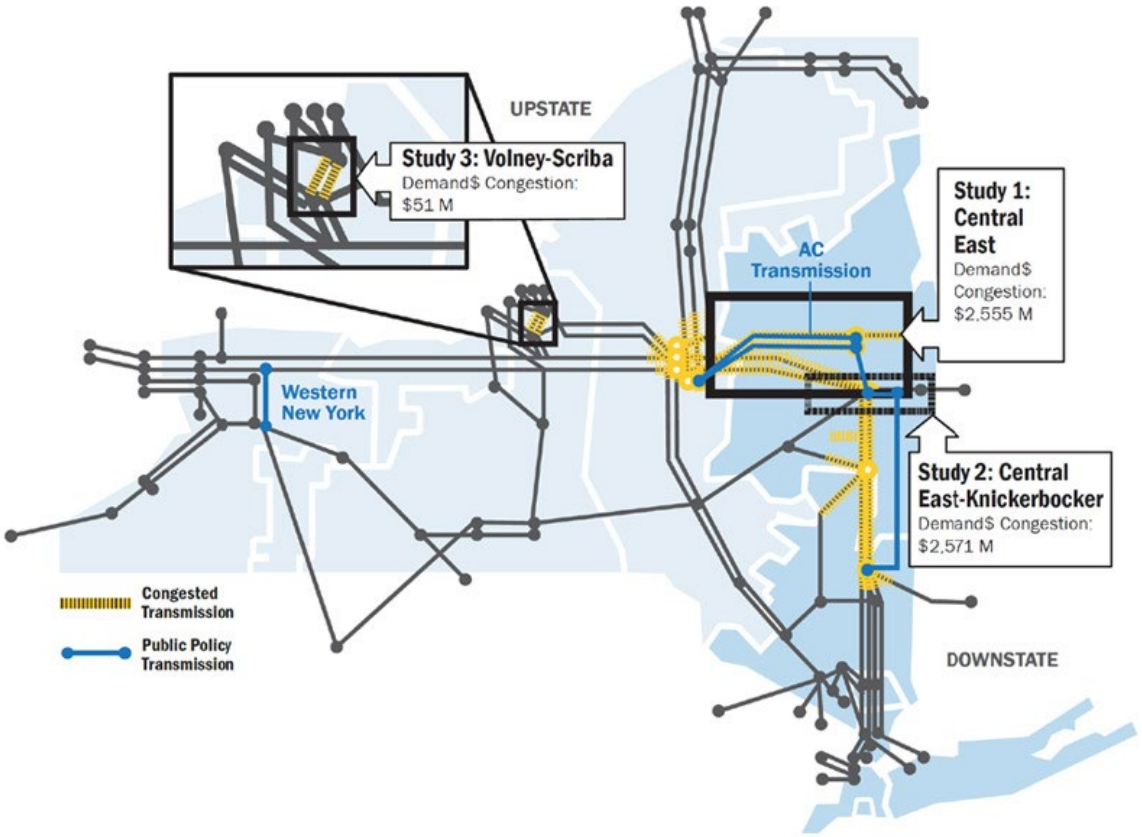
"The solutions … offered a measure of congestion relief and production costs savings but did not result in projects with benefit/cost ratios in excess of 1.0. Following the energization of the AC Transmission projects, the congestion is substantially reduced and shifts to the Central East-Knickerbocker corridor."

The study does not attempt to project changes in energy consumption caused by the COVID-19 pandemic. "The study provides in-depth analysis of long-term system usage trends and of system congestion and curtailment patterns over the next decade that are likely to persist notwithstanding the lower energy forecasts for 2020 and 2021 that the NYISO produced for the 2020 Gold Book," the ISO said.

'70x30' Scenario

CARIS' primary focus, however, is on the "70x30" scenario, reflecting the 2019 Climate Leadership and Community Protection Act (CLCPA) requirement that 70% of the state's end-use energy be generated by renewable energy systems by 2030.

The scenario, which modeled two hypothetical buildouts of renewable energy facilities, identified transmission-constrained pockets that could prevent renewable production from being fully deliverable to customers. Unlike the base case, it did not include a benefit-



2019 CARIS study groupings | *NYISO*

NYISO News

cost analysis.

The CLCPA included technology-based targets for distributed solar (6,000 MW by 2025), storage (3,000 MW by 2030) and offshore wind (9,000 MW by 2035), with a goal of making the electric sector emissions free by 2040.

The system model for the scenario added about 110 sites of land-based wind, offshore wind and utility-scale solar, along with additional behind-the-meter solar across the system.

Sufficient renewables were added to the system to equal 70% of state energy consumption, taking into account the "spillage" of generation when renewable production exceeds load within the New York Control Area — power that could either be exported or would have to be curtailed.

To study the impact of one potential renewable resource mix that could meet the 70x30 goal, the model included about 15,000 MW of utility-scale solar, 7,500 MW of behind-the-meter solar, 8,700 MW of land-based wind and 6,000 MW of offshore wind in addition to existing hydro generation. ISO staff also included a sensitivity analysis assuming the policy target of 3,000 MW of energy storage.

The study used a new screening tool to identify five "renewable generation pockets" where insufficient bulk and local transmission network (115-kV and some 230-kV lines) capacity could prevent renewables from being delivered to consumers statewide. The study concluded that about 11% of total potential renewable energy production of 128 TWh/year would be curtailed without transmission improvements.

The North Country pocket saw the highest curtailment by percentage, the highest curtailed energy by gigawatt-hours and the most frequent congested hours. Offshore wind also would be constrained in New York City (Zone J) and Long Island (Zone K) because of constraints on the land-based grid.

The increase in intermittent renewable generation meant lower production from the state's fossil fuel generators compared to the base case.

"In many cases, however, the reduced output is accompanied by an increased number of generator starts, indicating the need for dispatchable and flexible operating capabilities in the future. Fossil fleet operation can also be highly dependent on transmission constraints," the report said. "In particular, comparison of operations in the relaxed and constrained cases makes apparent that simple cycle combustion turbines may run more and start more often due to transmission constraints."

The conclusion: "Additional transmission expansion, at both bulk and local levels, will be necessary to efficiently deliver renewable power to New York consumers."

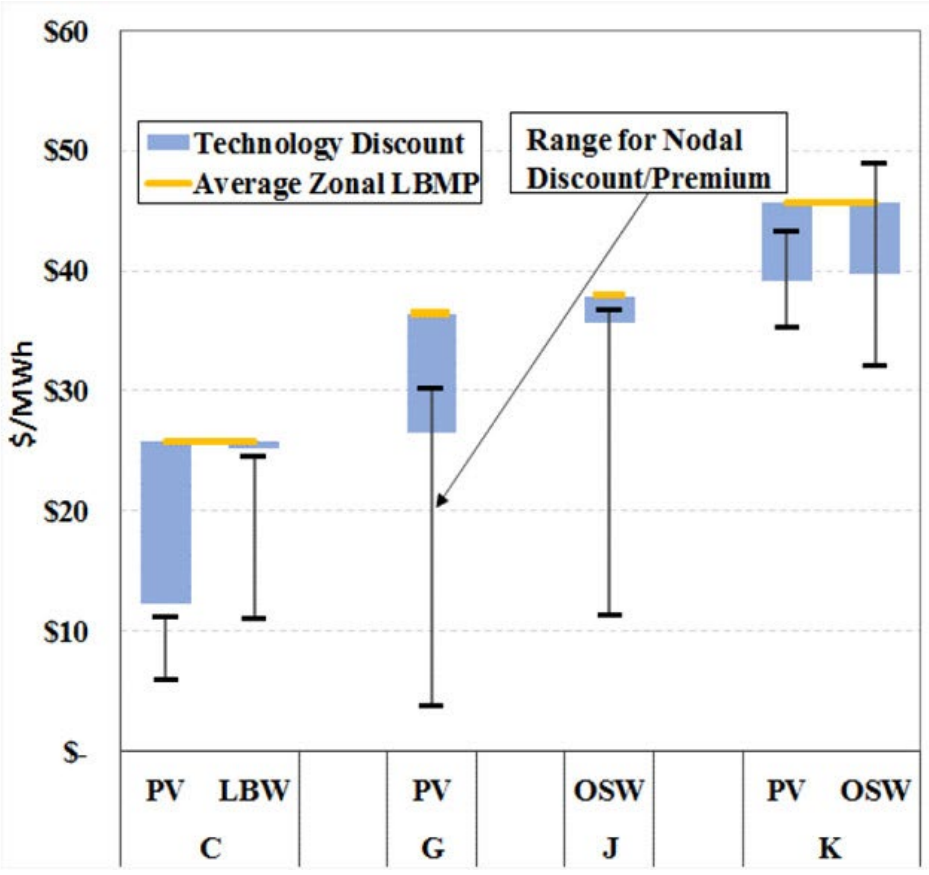
The report also found that energy storage could decrease congestion and help to increase the use of the renewable generation, particularly solar generation, when "dispatched effectively."

"The targeted analysis showed that energy storage likely cannot by itself completely resolve the transmission limitations in the pockets analyzed."

MMU Review

Pallas LeeVanSchaick of Potomac Economics *presented* the Marketing Monitoring Unit's *review* of the report, saying the transmission constraints identified in the 70x30 hourly

- Prices in hours of solar generation are heavily discounted
- Prices in hours of offshore wind generation are moderately discounted
- Prices vary widely at nodes within a zone, as renewables cause local transmission bottlenecks in some places



Technology and nodal discounts in 70x30 case | *Potomac Economics*

NYISO News

resource modifiers (HRM) scenario "also substantially affects investment incentives" for intermittent renewable generation and battery storage. Under HRM, renewable resources are modeled to allow their outputs to change on an hourly basis.

Wholesale market incentives will encourage developers to locate assets where the transmission system is not already saturated with a particular renewable technology, the MMU said.

While renewable generation and battery storage projects may rely on revenues from sources outside the wholesale market, "the wholesale markets are as important as ever in channeling investment," LeeVanSchaick said.

Many renewable generators seek to reduce market risk by signing long-term (20- to 25-year) contracts for "index" renewable energy credits, which pay a price per megawatt-hour equal to a fixed strike price minus the index price for a nearby pricing hub. A generator with a strike price of $65/MWh located near a trading hub that averaged $30/MWh over a month would receive $35/MWh for its RECs for that month.

But index RECs don't eliminate all risks in the 2030 scenario, the MMU said.

The MMU cited the "technology discount" — the difference between the simple average zonal LBMP in the day-ahead market and the generation-weighted average zonal LBMP in the real-time market by technology. This affects technologies that tend to produce electricity at times when zonal LBMPs are below the day-ahead average.

Generators also face a "nodal discount" — the generation-weighted average differential between the zonal locational-based marginal prices and the nodal LBMP for a particular technology and location. This reflects reduced revenue when local transmission constraints further discount the energy revenue to a particular technology and location.

Neither of the discounts are much of a factor in 2020, LeeVanSchaick said. "But you see those tend to grow over time as [intermittent renewable] penetration increases."

In the 70x30 scenario, the MMU found technology discounts of 27 to 87% of average zonal LBMPs for solar generation in Zones A to G, with solar in Zone K facing a potential 14% revenue reduction. Land-based wind would face a 2 to 21% discount in Zones A to E, with a 6 to 13% discount for offshore wind in Zones J and K.

Nodal impacts could range, from a 79% discount to a 29% premium for solar. Land-based wind could see between a 56% discount to an 8% premium, with offshore wind ranging between a 68% discount to 23% premium.

The MMU emphasized that the 70x30 scenario does not constitute a prediction of the resource mix in 2030, and its analysis is not a prediction of future market outcomes. It said the scenario does provide useful information about market incentives as the state works toward the 70x30 goal.

"If additional entry into saturated areas is motivated by raising index REC prices in the future, it will result in large financial risks to renewable generation developers that invest sooner (i.e., before the area has become saturated with a particular intermittent generation technology)," the MMU said. "Thus, a stable and predictable policy regarding index REC price levels may facilitate progress towards the state's goals."

It also said the high renewable penetration in the 2030 scenario would result in "strong incentives" for entry by unsubsidized battery storage developers.

"This market response would moderate energy prices and reduce market risks for renewable generation investors. Hence, a competitive wholesale market for energy, ancillary services and capacity will ultimately facilitate state policy objectives."

Next Steps

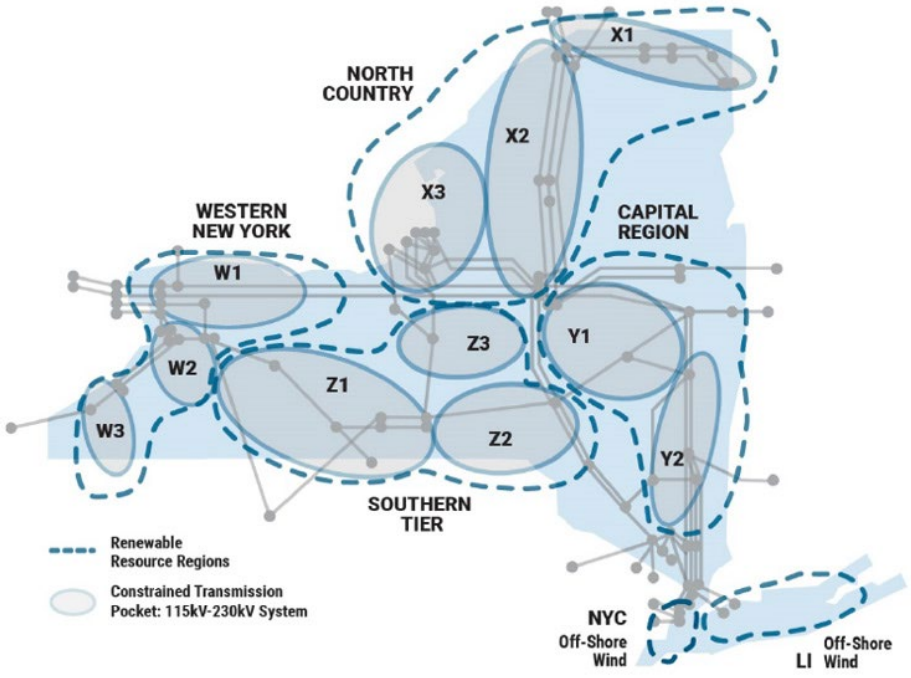
CARIS Phase 1 will be brought to a vote at the July 1 Management Committee meeting and is expected to be considered by the NYISO Board of Directors at its July meeting.

The ISO said it will build on the CARIS results in the upcoming 2020 Reliability Needs Assessment and the Climate Change Impact and Resilience Study.

After CARIS Phase 1 is approved by the board, NYISO will begin Phase 2 of the economic planning process, in which developers will be invited to propose projects to alleviate the identified congestion.

The ISO will evaluate proposals to determine their impact on congestion and whether the projected economic benefits make the project eligible for cost recovery under the ISO's rules.

"While the eligibility criterion is production cost savings, zonal LBMP load savings (net of transmission congestion contract revenues and bilateral contracts) is the metric used in Phase 2 for the identification of beneficiary savings and the determinant used for cost allocation to beneficiaries for a transmission project," the ISO said. ■



NYISO identified five "renewable generation pockets" where insufficient bulk and local transmission network capacity could prevent renewables from being delivered to consumers statewide. | *NYISO*

NYISO News

'Astonishing' Buildout Needed for Clean NY Grid

Continued from page 1

ISO retained Brattle to simulate the resources that can meet state policy objectives and energy needs in order to inform planning for reliability and market design over the next two decades. (See *N.Y. Looks at Grid Transition Modeling, Reliability*.)

Three Scenarios

Brattle developed three scenarios to address a range of questions from NYISO and stakeholders, including: an existing technologies case; an increased flexibility case (with expanded interties to Hydro-Québec); and an expanded transmission case (with new lines southbound).

The study is modeling for a 20-year time horizon. Given the amount of uncertainty about what available technologies, costs, and state and market rules will be, the ISO and its stakeholders thought it was important to use alternative scenarios to get a sense of how much the results change under different assumptions, said Brattle Senior Associate Roger Lueken.

"One thing to stress is that there is a lot of uncertainty in the study both in terms of the setup and the results," Lueken said. "Of course, there's a lot more scenarios that we could look at, but these were the three that it sounded like were of most interest."

The study compares each of the scenarios to the high electrification case and to the base case results, he said.

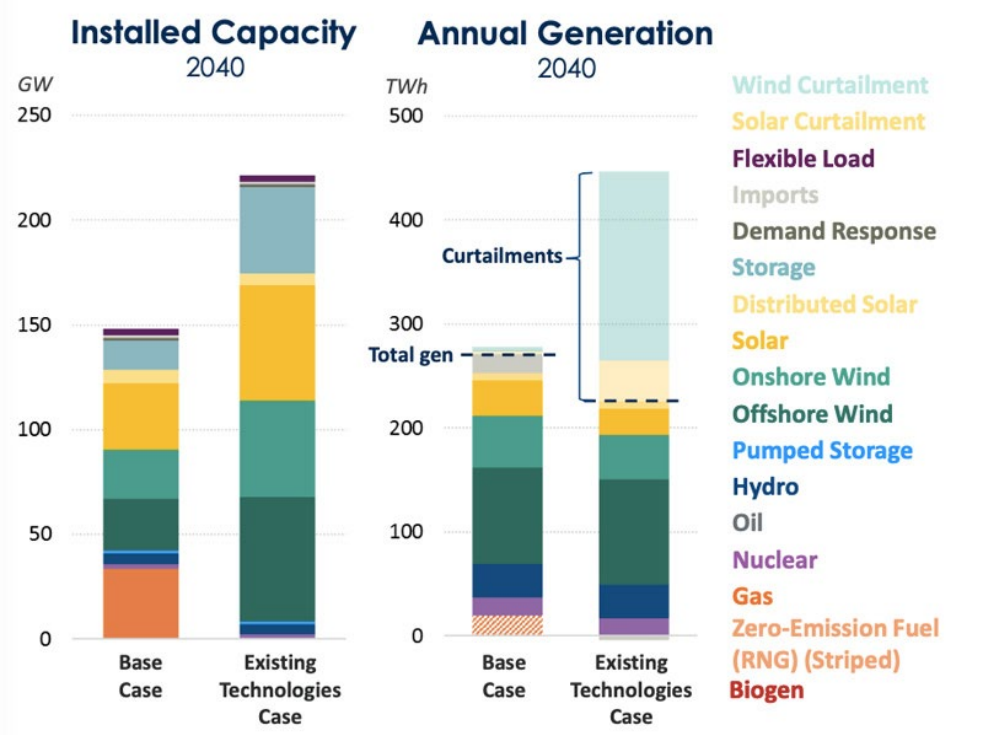
In addition to the CLCPA, a key public policy driving decarbonization of the grid is the Regional Greenhouse Gas Initiative, the Northeast regional cap-and-trade program that had an average 2019 price of $5.40/ton of carbon dioxide, which is expected to reach $12.60/ton by 2030.

The study also considers the zero-emissions credit (ZEC) program for payments to New York nuclear plants, which expires March 2029, and the Department of Environmental Conservation rule to reduce NO_x emissions from peaking plants, whereby peakers built before 1986 will most likely retire instead of retrofitting to meet emissions requirements.

The state's new emissions regulations go into effect May 1, 2023, and generator compliance plans were due March 2. (See *NY DEC Kicks off Peaker Emissions Limits Hearings*.)

Through the Looking Glass

The existing technologies case for 2040 gives high-level insights into a large overbuild of renewables (+80 GW from current levels) and storage (+27 GW) to meet load in all hours, with large curtailments of 221 TWh, or 50% of projected generation.



The existing technologies case for 2040 gives high-level insights into a large overbuild of renewables (+80 GW) and storage (+27 GW) to meet load in all hours. | *The Brattle Group*

In addition, retirement of gas plants by 2040 causes unforced capacity reserve margins to fall below planning reserve margins, and load falls by 50 TWh without in-state renewable natural gas production.

"In the second case — increased flexibility — we model expanded interties to Hydro-Québec as being able to provide flexibility, and we model more flexible load on the system," Lueken said.

Lueken said "there are many different ways load can be flexible," but Brattle chose to focus on two.

"The first is controlled electric vehicle charging, so people with EVs can control at what time of day they charge," he said. The second is controllable heating and air conditioning loads, with the study assuming that buildings are outfitted with smart thermostats or types of HVAC that allow occupants to vary their thermostat point in order to shift their load from hour to hour.

"The third case is an expanded transmission case where we model transmission along key corridors from upstate New York into downstate New York, and between Zone J [New York City] and Zone K [Long Island]," Lueken said.

The New York Public Service Commission in May authorized a study to identify distribution upgrades, local transmission upgrades and bulk transmission investments needed to meet the state's clean energy goals (*20-E-0197*). (See *NYPSC Launches Grid Study, Extends Solar Funding*.)

The third case is designed to show how the amount of transmission affects what types of resources are built and where they're added.

Brattle made three specific updates to the scenario. The first update was increasing transmission from zones A through E (Western to Central New York), and to zones G, H and I (Central and Lower Hudson) by 2,000 MW, and more than doubled the base case transfer limit from 1,900 MW to 3,900 MW, Lueken said.

"The second update was increasing transmission from Zones G, H and I into the Zone J

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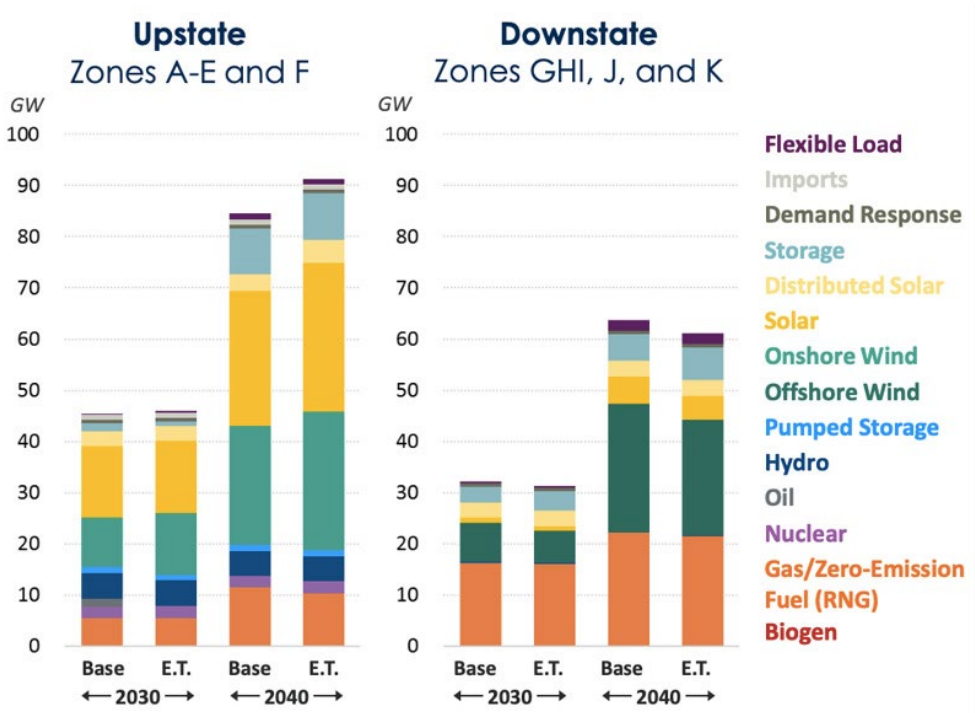
by 2,000 MW, upping the transfer limit in the base case from 3,900 MW to 5,900 MW. Both of those upgrades were unidirectional, so we only increased the flow limit in the downstate direction," Lueken said.

The third update was applied bidirectionally, assuming that the transmission lines between Zones J and K increase by 1,000 MW, so that an additional 1,000 MW can flow from J to K and vise-versa, he said.

In response to a question about assumed costs for the transmission buildout, Lueken said "we did not compare the cost of building the increased interties to Hydro-Québec to the benefits; we simply reasonably assumed that they occurred and checked what happens to the resulting resource mix. The same is true here — we don't make assumptions about what these upgrades cost, and we don't compare the benefits of these upgrades to some estimate of what they might cost."

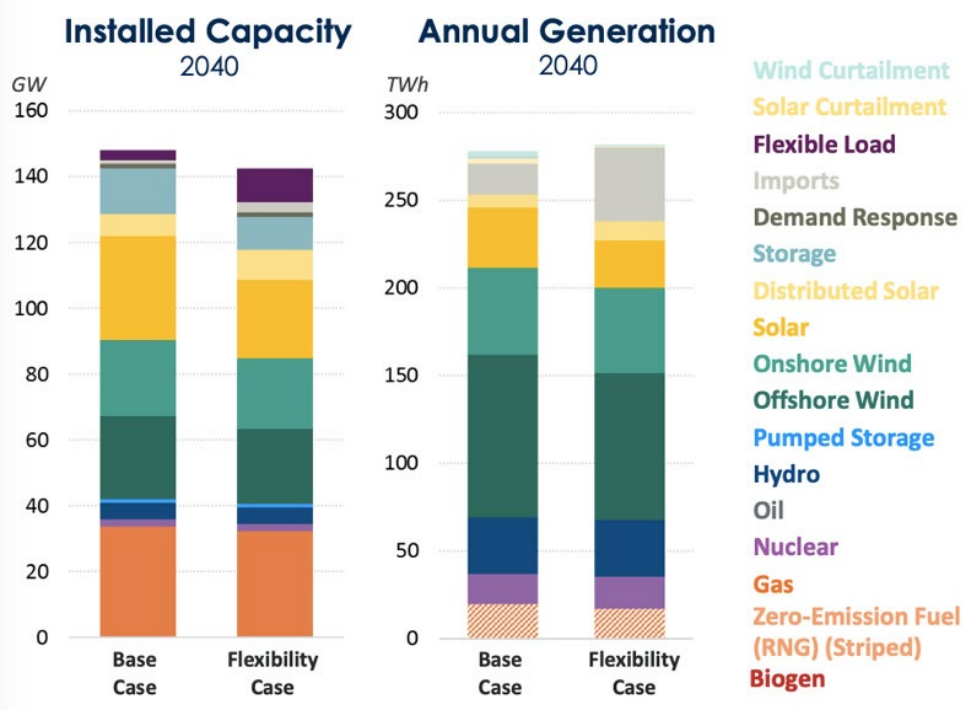
Merits a Closer Look

The study's main point is that the projected renewable needs for 2030 are in line with the technical potential for renewables in New York, but projected needs for 2040 will possibly exceed that potential, Lueken said.



The expanded transmission case for 2040 shows upstate capacity grows, as increased transmission enables more capacity to be built in lower-cost areas. | *The Brattle Group*

He reiterated his cautionary note about the uncertainty around what the actual limits are, especially the estimates from the Department of Public Service, the New York State Energy Research and Development Authority and the National Renewable Energy Laboratory.



The increased flexibility case for 2040 gives high-level insights of increased HQ imports (+24 TWh net), zero-emission generation largely unchanged and increased flexible load capacity resulting in less storage capacity. | *The Brattle Group*

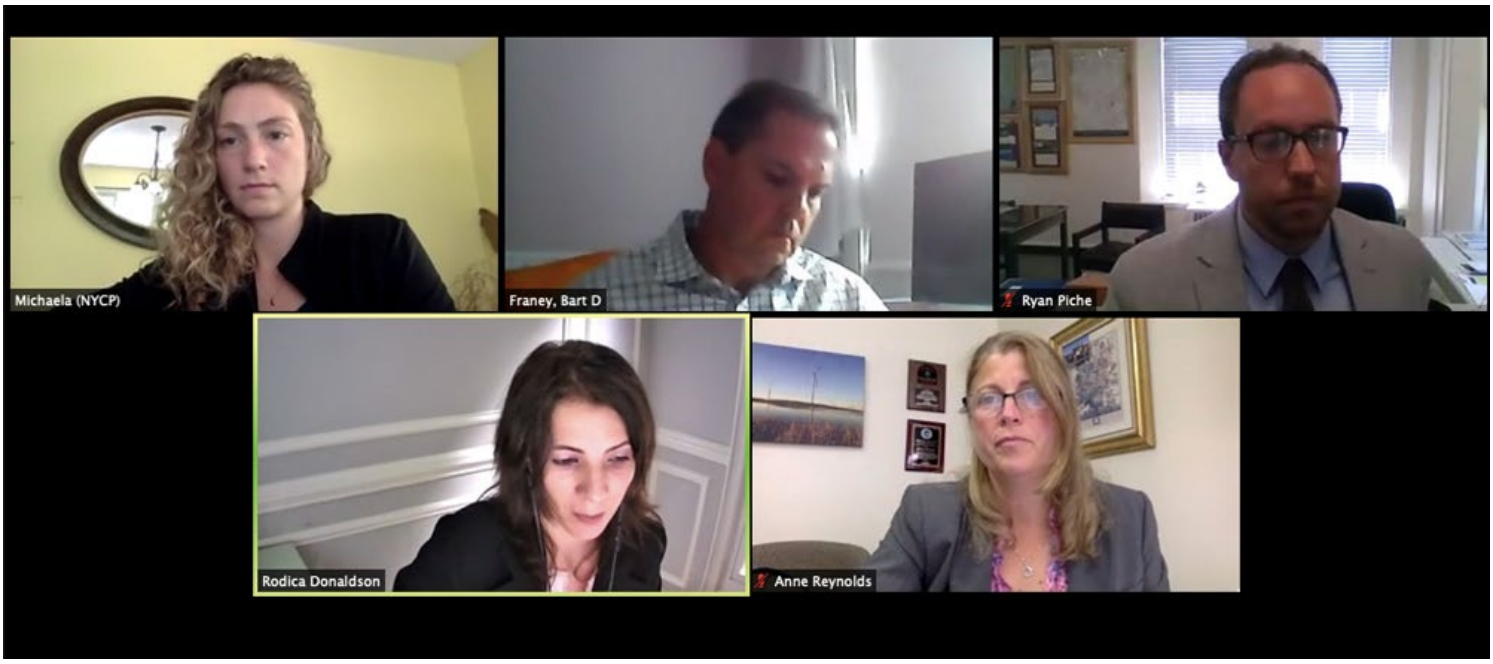
"One thing that might be worth further study by the labs or by the state or someone is getting a better sense of what these limits really are, and how that might influence the types of resources that are built," Lueken said. "This is most obvious looking at solar, where for the amount of potential the limits range from 7 GW to 50 GW to almost 1,000 GW."

Newell wrapped up the presentation by emphasizing Lueken's last point: "The one area for further study is how do these needs relate to resource potential, including how much offshore wind you can get without transmission being built to access whatever lease sites are developed."

"In any case, we're talking about massive amounts of intermittent resources that are difficult to rate properly in terms of capacity," Newell said. "Their intermittency is accounted for in installed capacity reserves studies, but they've become such a big part of the system, it's worth taking a closer look at how you look at multiple years of wind and solar data, and more robustly incorporate that into the analysis, and extend that to resource accreditation." ■

NYISO News

New Yorkers Plug New Tx Need for Clean Future



Clockwise from top left: Michaela Ciovacco, New York for Clean Power; Bart Franey, National Grid; Ryan Piche, Lewis County, N.Y.; Anne Reynolds, ACE NY; and Rodica Donaldson, EDF Renewables | *ACE NY*

By Michael Kuser

Renewable energy experts and grid planners joined government officials Thursday to discuss how to address New York's outdated transmission system, which can't move enough clean energy from upstate generation sources to key load centers in and around New York City.

Anne Reynolds, ACE NY | *ACE NY*

"New York will be bringing more and more renewable energy online," said Alliance for Clean Energy New York (ACE NY) Executive Director Anne Reynolds, who opened the meeting. "This is good news — wind and solar are pollution-free, and 22,000 New Yorkers already work in the renewable electricity industry. But for New York to actually achieve its renewable electricity goals, we need to update the grid, parts of which were built more than half a century ago."

An estimated 226 people listened in on the virtual town hall co-hosted by the American Council on Renewable Energy and the Solar Energy Industries Association.

ACE NY lobbied the State Legislature for a budget *bill* that passed in April, the Accelerated Renewables Growth and Community Benefit Act, which aligns state law, bureaucratic practices and policies — including property tax laws — with the clean energy goals outlined in last July's landmark Climate Leadership and Community Protection Act (CLCPA) (*A8429*). (See *NY Renewable Supporters Push for New Siting Agency*.)

The bill directed the Public Service Commission to authorize a study, which it did in May, to identify distribution upgrades, local transmission upgrades and bulk transmission investments needed to meet the state's clean energy goals (*20-E-0197*). (See *NYPSC Launches Grid Study, Extends Solar Funding*.)

New York Sen. Kevin Parker | *ACE NY*

"I agree with the premise that we are going to need more transmission if we're going to meet the goals of the CLCPA, the most aggressive set of climate standards in the entire nation," said Sen. Kevin Parker, chair of the Senate Energy and Telecommunications Committee.

"Now the hard work has begun, which is how do we actually meet the goals. I very much believe that transmission is going to be really critical in that, and organizations like ACE NY are going to be leading the charge," Parker said. "This also is happening in a time at which ... our economy has been way slowed down, and if we look at where we're going to produce full-time jobs at a living wage with benefits, the clean energy economy is the next best place to do that."

However, reduced state revenues stemming from the slowdown means "we have to produce more green using less green," Parker said.

Additional Buildout

Ali Zaidi, Cuomo administration | *ACE NY*

Two things are at the heart of the new climate law, said Ali Zaidi, Gov. Andrew Cuomo's deputy secretary for energy and environment: "One is dramatic transformation of the grid to 100% clean, and the second is an expansion of that grid to reach more and more sectors of the economy."

One of the state's most powerful tools in decarbonizing buildings, industry and transportation is to back out existing sources of energy in those sectors and replace them with electrons

NYISO News

generated in a clean way, Zaidi said.

"We have hundreds of miles of power lines that are on their way to being built in this state in the very near term, and we need to bird-dog that progress and make sure it is done on time," Zaidi said. "It's critical that we build what we already know we need and what is barely far along in the development process ... and use data and analysis to inform where we are going to speed up additional buildout."

As part of its "Grid in Transition" initiative, NYISO retained The Brattle Group to forecast future resource mixes and help inform planning for reliability and market design over the next two decades, with the final report presented June 22. (See related story, *'Astonishing' Buildout Needed for Clean NY Grid*.)

"Most people know that the interconnection points that can efficiently accommodate large renewable generation projects in upstate New York are becoming much harder to find," said Bart Franey, director of transmission planning, asset management, systems and data for National Grid.

The constraints are partly because of generation and transmission development being largely siloed from each other, he said.

"New flow patterns across the networks are creating a growing issue of curtailments on renewable energy, and generation development continues to outpace that of transmission," Franey said. "The result is a suboptimal solution for ratepayers."

National Grid has been exploring this issue for two years and looking for ways to upgrade what are referred to as "byways" in its transmission network, he said.

The company "has focused on creating upgrades that are available to deliver renewable resources to the bulk, or the highways," Franey said. "These studies assumed light load conditions with an objective of minimizing curtailments, and it resulted in some really exciting opportunities around optimally sizing upgrades using a [renewable energy credit]-based benefit approach."

When National Grid analyzed its systems and identified projects, they realized that "in some cases, the least-cost byways solution would in fact be a greenfield project, used specifically to deliver renewables," Franey said. "We refer to them as collector stations, but they would really be a form of integrated resource planning."

Developer and Local Insights

Rodica Donaldson, EDF Renewables | *ACE NY*

"In New York alone, we have a pipeline of over 3 GW of solar and storage in various stages of development and have partnered with Shell Energy for the development of offshore wind, and we have a number of solar projects already online," said Rodica Donaldson, senior director for commercial transmission and analytics at EDF Renewables North America.

"The transmission risk is important to renewables because if we have high curtailment, which has been identified in the latest [*Congestion Assessment and Resource Integration Study*] by the New York ISO, that means high risk for us because we cannot be delivered as low-cost energy for loads," Donaldson said.

The high risk of congestion and curtailment also means that the transmission system is reaching capacity, she said.

"We have curtailment; we have depressed LMPs within that pocket; and those are financial costs for us," Donaldson said. "As a generator, when we look at developing projects, this risk can challenge the ability to secure financing and even can make the project uneconomic. So, for us, a scenario without transmission investment is a high-risk environment."

Ryan Piche, Lewis County, N.Y. | *ACE NY*

"We are home to 27,000 residents over 1,200 square miles, so when you talk about room for green energy growth, this is where it is: It's upstate," said Ryan Piche, manager of Lewis County in the Adirondacks. "No offense to Sen. Parker, but it's not in Brooklyn."

Despite having open space, the needs of the local community in Lewis County and elsewhere are very important, he said.

"We know our community better than anyone, and we need to be the ones who are deciding which areas are prime for growth and which areas need to be preserved," Piche said. "We're the ones who understand viewshed and habitats. The 'solar tsunami' is a fun little phrase, but think about a tsunami — it can overwhelm you. I think it is important that the local governments draw a line in the sand and understand what is going to be acceptable and what is not." ■

National Grid Simmons Station site in Humphrey, Cattaraugus County, N.Y., an example of a "byway" in the company's transmission network | *National Grid*

NYISO News

NY Climate Action Council Looks at Deep Decarbonization

E3 Presents Study Ahead of Public Proposal Set for August

By Michael Kuser

New York's Climate Action Council met Wednesday to lay the groundwork for a scoping plan to help the state achieve its nation-leading clean energy goals despite the massive disruptions caused by the COVID-19 pandemic.

CAC Co-chair Alicia Barton, NYSERDA | *New York DPS*

"Early on, even as we were in the midst of the economic shutdown that we knew was going to be a challenge for our industry, the state was ready to lead on clean energy," said CAC Co-chair Alicia Barton, serving her last week as New York State Energy Research and Development Authority chair before returning to private industry in Massachusetts.

Barton noted that the last time the CAC met on March 3, its 22 members talked "about the opportunities New York has to lead the nation and lead the world with the promise of the Climate Leadership and Community Protection Act [CLCPA], with the ambition of that law."

"Since that time, the pandemic crisis has overtaken and changed so many things, but we still have the opportunity to lead," Barton said. "We're in the process of revising the models for an economic recovery that puts clean energy back in the center."

The CAC's work is part of a broad effort by regulators, state agencies and NYISO to transition the state's power sector and entire economy away from fossil fuels and toward renewable energy, with NYSERDA and the Public Service Commission on June 18 having released a *white paper* on the state's Clean Energy Standard and how to achieve it.

The CLCPA mandates, among other targets, that 70% of the state's electricity come from renewable resources by 2030 and that generation be 100% carbon-free by 2040. (See *Cuomo Sets New York's Green Goals for 2020*.)

Specific Pathways

CAC Co-chair Basil Seggos, New York DEC | *New York DPS*

The CLCPA also requires the state's Department of Environmental Conservation to undertake a rulemaking to establish statewide emission limits for 2030 and 2050, and to work with NYSERDA to establish a value of carbon as an evaluation tool for agency decision-making, said DEC Commissioner and CAC Co-chair Basil Seggos, who heads the council's advisory panel.

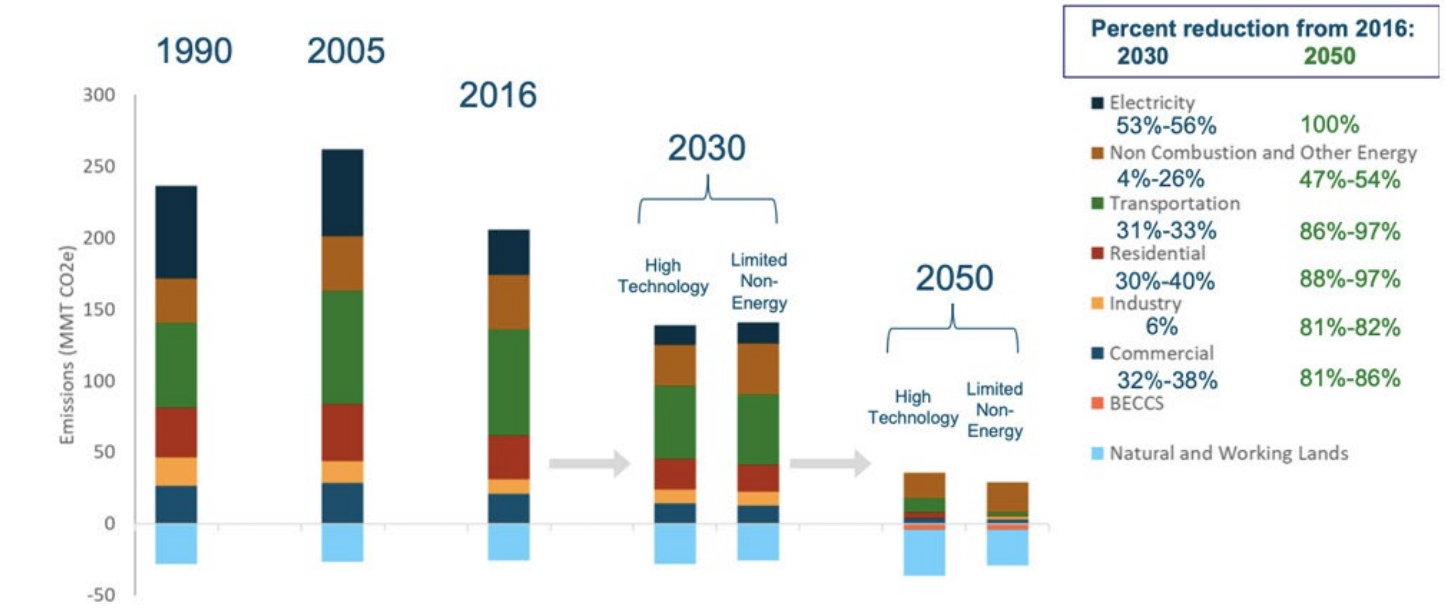
"We're basically setting up the goalposts for the council's planning," Seggos said. "We anticipate holding a stakeholder conference in July, and to roll out a public comment position in August."

Tory Clark, a director at Energy and Environmental Economics (E3), *presented* a *report* commissioned by the state on pathways to deep decarbonization, envisioning four main pillars that all require immediate action:

Tory Clark, E3 | *New York DPS*

- Energy efficiency, conservation and end-use electrification.
- Switching to low-carbon fuels.
- Decarbonizing the electricity supply.
- Negative-emission measures and carbon-capture technologies.

"The most impactful [emission-reduction] measures that we've included are methane mitigation and climate-friendly refrigerants," Clark said. "I'll note that this is an area in particular where we think there is more room to refine our analysis, both in the detail that we



New York net greenhouse gas emissions for selected years by scenario | *E3*

NYISO News

have that reflected the existing emissions, and the measures and policies that can help bend that curve down."

Anne Reynolds, executive director of the Alliance for Clean Energy New York, noted that the study said the grid will need firm, dispatchable capacity such as bioenergy or hydropower and "wondered whether you assumed that dispatchable capacity, and if so, how much. And if you had that, you'd need less renewables."

Upstate and downstate, the study projects 9.5 GW of storage installed by 2050, nearly 25 GW of offshore and onshore wind, and nearly 46 GW of solar.

"The firm, dispatchable capacity is the broad, umbrella term, and probably a mix of technologies will step in and serve that role," Clark said.

"We now model batteries able to store energy for four, maybe eight, hours, but longer-duration storage has not been demonstrated at scale," Clark said. "But there are many companies working on it, so I would put that in the innovation bucket, where hopefully there's continued innovation and that would be able to step in and be part of the solution." The study models today's technology, but the mix could include using existing generators to combust bioenergy or hydrogen, hydroelectric power, nuclear, carbon capture and storage — all proven technologies that are included in the analysis, she said.

"Since we're really just talking about these small winter periods [peaks] throughout the year, we have bioenergy capacity [nearly 17 GW in 2050] ... just sitting around, but they only run a very small share of the year, just to serve that need," Clark said. "So, it's a niche role that in addition to the big players, the wind and solar that are generating throughout the year and providing the majority of the electricity generation for New York, we have this small role for firm dispatchable capacity."

EVs, Biofuels and Data

Peter Iwanowicz, Environmental Advocates of New York | *New York DPS*

Peter Iwanowicz, executive director of Environmental Advocates of New York, asked whether the study saw electric vehicles playing a role in utility-scale storage.

The study concluded "that EVs have a pretty huge potential to shift load when they charge for up to 12 hours over the course of the day, based on driving patterns and grid technology, so that does play a similar role to some of our battery storage," Clark said.

National Fuel Gas Distribution President Donna DeCarolis | *New York DPS*

"I was really pleased to see the inclusion of and discussion around RNG [renewable natural gas] and things like hydrogen blending," said Donna DeCarolis, president of National Fuel Gas Distribution. "How do we see that being studied as the work of this council progresses?"

"The issue of science matters," said Gavin Donohue, CEO of the Independent Power Producers of New York. "This study is a true, objective study and one that is needed to achieve these herculean goals. Having a kitchen-sink approach to the new technologies is very important. What comes out of the stack is what's important, not what goes into the stack, from an environmental compliance standpoint."

IPPNY CEO Gavin Donohue | *New York DPS*

On mitigating the growth of emissions, Department of Transportation Commissioner Marie Therese Dominguez highlighted that "New York uses the least energy per capita for transportation purposes than any other state in the nation," mainly because of the subway system in New York City and the annual $6 billion investment in mass transit statewide.

"The department has also committed more than $1 billion in infrastructure improvements over the last several years to reduce single-vehicle occupancy use and to increase the movement of goods by means other than truck, including strategic investments in seaports and freight rail," Dominguez said.

PSC Chair John B. Rhodes | *New York DPS*

PSC Chair John B. Rhodes noted the initiatives to unlock transmission "that are called for by the Accelerated Renewables Growth and Community Benefit Act" enacted in April.

"We're making progress where it needs to be made and are counting on the council and the [advisory] panel to shape the overall direction," he said. ■

PJM News

PJM Revises Consultant Scope for ARR/FTR Review

By Michael Yoder

PJM has revised its proposed review of its auction revenue rights (ARRs) and financial transmission rights markets as stakeholders decide whether to put their work on the issue on hiatus until a report is completed.

Dave Anders, PJM | © RTO Insider

At Friday's *ARR/FTR Market Task Force* meeting, PJM's Dave Anders presented the revised *draft* scope of work to be done by an external consultant in its review of the ARR-FTR construct, a project recommended in last year's independent consultant *report* on the GreenHat Energy default.

Anders said PJM received "significant feedback" after last month's task force meeting and decided to take a "higher-level view" to ask broader structural questions than the RTO had originally *proposed*.

While the overarching question of whether load is receiving optimal value from the ARR/FTR markets remains the same, Anders said, the revised questions seek to avoid conflicts between load-serving entities and financial traders over what is to be examined. (See *PJM ARR/FTR Review Could Pit LSEs vs. Financial Traders*.)

"This thinks about the big-picture questions first and then gets down to the more granular considerations," Anders said.

The new work scope requests that the consultant examine ARRs and FTRs both separately and as a system working together and make recommendations for potential improvements. The questions include a look at the reason the markets were created; whether they are producing the desired outcome; and whether there are alternatives to achieving the desired results.

Anders said the request for hiring the consultant should be posted by the end of this week. He said the RTO hopes to have the consultant start work by the end of July and to have a report done by October.

Sharon Midgley, Exelon's director of wholesale market development, said PJM's work scope changes were "excellent" and "raised the level of conversation" instead of assuming any outcomes. She asked if PJM will have the consultant look at the technical platforms running the ARR-FTR markets to ensure the technology is up to date and able to be expanded or changed if needed. "I would hate for us to go through the process and not be able to implement certain things because we don't have the systems to support it," she said.

Anders said the consultant may not be able to scrutinize the IT platforms because PJM is searching for someone who understands "the economics" of the market and not necessarily the technology running the programs.

Jim Davis of Dominion Energy said the consultant questions represent what his company had in mind when discussions about the markets were being proposed. Davis said the consultant should spend "sufficient time" considering market design changes to optimize the value or lower the risk to load.

"The scope of work is well defined yet flexible as well," Davis said.

PJM vs. IMM

After Anders presented the updated scope of work, he discussed potential pathways forward for the task force while the consultant completes its review. Anders said stakeholders have expressed varying opinions, ranging from putting the group into hiatus to looking at some limited-scope items over the next few months.

PJM's recommendation is to put the task force on hiatus until the consultant completes its work, Anders said, because the broad range of work to be completed may result in changes to aspects of the market construct. He said continuing work on anything that could contradict the consultant's report would not be a good use of stakeholder time.

"PJM and stakeholders don't want to give the impression that they're driving towards some solution at the same time the consultant is doing a broad review," Anders said.

Howard Haas, chief economist for Monitoring Analytics, PJM's Independent Market Monitor, said he appreciated the work that went into formulating the work scope but disagreed with the hiatus recommendation. He said conducting a third-party review of the markets was only one aspect of the recommendation that came from the GreenHat report and that it asked PJM, the Monitor and stakeholders to do a "holistic review" of the entire ARR-FTR process.

Slowing down the pace of the task force's work makes sense during the consultant's review, Haas said, but the amount of information stakeholders need to cover requires continuous effort. Haas suggested continuing discussions and a presentation of methodologies, analysis and data needed to facilitate a discussion of any needed changes to the current ARR/FTR market.

"There's a lot of work that has to be done with or without the consultant's report," Haas said.

Anders said the Market Implementation Committee will vote July 8 on whether to put the task force on hiatus or continue work. The MIC will vote after receiving the results of a nonbinding poll of task force members on the same question.

Stakeholder Opinions

Davis said he agreed with Haas' recommendation to continue the task force work at a slower pace. He also suggested that the consultant provide interim updates to the group as it conducts its review to have a better understanding of the issues being examined.

Susan Bruce of the PJM Industrial Customer Coalition said she was "of two minds" when thinking about how the task force should proceed. She said that although she understands PJM's interest in allowing the consultant to do its work without outside influence, she is open to continuing conversations on market dynamics to avoid losing the sense of momentum that has built during task force discussions since January.

"This is a complicated nut, and I think there are a lot of issues here to discuss," Bruce said.

Several stakeholders expressed support for a hiatus. Jim Benchek of FirstEnergy said he is concerned that the continuing mixture of data production and presentations by PJM and the Monitor at task force meetings could influence the content of the independent report.

Gary Greiner, director of market policy for Public Service Enterprise Group, said stakeholders need to recognize that the GreenHat report indicated PJM's markets are not fundamentally broken and did not constitute a "house on fire" situation that needed immediate attention. He said taking more time and being thoughtful in deliberations would be beneficial for stakeholders and at the same time allow the consultant to do its work unimpeded.

"If the consultant comes back and we dismiss everything they've done out of hand, then we've done a pretty poor job on our part," Greiner said. ■

PJM News

Gen. Owners, Other Suppliers Key to EOL Win

Continued from page 1

End of Life Task Force

AMP, ODEC and the PJM ICC have been fighting to increase the transparency of the EOL process since at least February 2016, when they won approval of a senior task force to consider development of RTO-wide criteria for EOL transmission facilities. (See *PJM TOs Oppose Proposal to Develop End-of-Life Criteria*.)

Some TOs have established criteria for such projects under FERC Form 715, while others consider them supplemental projects — improvements not required for compliance with PJM system reliability, operational performance or economic criteria. The RTO does not approve supplemental projects but does study them to ensure they won't harm reliability.

PJM says TOs' supplemental projects totaled almost $3.4 billion in 2019, more than double the less than $1.5 billion in regionally planned baseline projects. It was the fifth year out of the last six in which the costs of supplemental projects exceeded those of baseline projects.

Load interests, who noted that much of the grid is 30 to 50 years old and in need of replacement, say EOL projects should be planned regionally by PJM to optimize and control spending. LS Power would like to see the projects eligible for competitive bidding under Order 1000.

The *Transmission Replacement Processes Senior Task Force* held more than two dozen meetings over two years before reaching an impasse. The group was sunset in July 2018. (See *PJM Stakeholders End Transmission Replacement Task Force*.)

The group ended its work five months after FERC approved the TOs' request to move language governing supplemental projects from PJM's Operating Agreement to Tariff Attachment M-3, while requiring changes to improve transparency. (See *FERC Orders New Rules for Supplemental Tx Projects in PJM*.)

Ed Tatum, American Municipal Power | © *RTO Insider*

In January 2019, AMP and ODEC won 69% support of the Markets and Reliability Committee for changes to Manual 14B that would give PJM more control of supplemental projects. PJM officials refused to implement the changes, however, saying they would conflict with FERC rulings. After months of negotiations, AMP and LS Power reached agreement with the TOs on manual language to prevent TOs from proposing supplemental projects designed to meet regional needs. (See *PJM TOs Sign off on Supplemental Project Deal*.)

Last fall, Tatum won approval of a new issue charge that resulted in five special MRC meetings to consider "*Transparency and End of Life Planning*" — discussions that resulted in the joint stakeholders' EOL proposal and PJM's alternative.

The joint stakeholders' *proposal* would amend the OA to require TOs to notify PJM and stakeholders of any facility nearing the end of its life at least six years before its retirement date. The projects would be included in five-year planning models and potentially opened to competitive bidding.

The Transmission Owners Agreement-Administrative Committee (TOA-AC) laid out its own EOL proposal, which aligned with the position of PJM staff, in proposed *amendments* to Attachment M-3 (*ER20-2046*). It would require TOs to have a formal program for EOL determinations and to identify potential EOL projects five years in advance. Projects that "overlap" with Regional Transmission Expansion Plan reliability violations would be included in a competitive window seeking "the more efficient and cost-effective solution."

The TOs say the proposal would increase transparency and improve planning coordination with PJM while honoring their rights and responsibilities over asset management. The joint stakeholders contend it would do little to improve transparency or change the status quo.

Element of Surprise

The TOs gave notice on May 7 that they were considering the M-3 amendments, starting a 30-day clock to accept comments before they could make the filing under Section 205 of the Federal Power Act. Their action forced the joint stakeholders to seek a vote at the May 28 MRC meeting — earlier than stakeholders had planned, Tatum said. "We felt like it might have been a little too soon, but we had to give it a run," he said.

Susan Bruce McNees Wallace & Nurick	**June Vote**
Air Products & Chemicals, Inc. (EUC)	Yes
ArcelorMittal USA LLC (EUC)	Yes
Gerdau Ameristeel Corporation (OS)	Yes
Kimberly-Clark Corporation (GO)	Yes
Lehigh Portland Cement Company (EUC)	Yes
Letterkenny Industrial Development Authority (ED)	Yes
MeadWestvaco Corporation (EUC)	Yes
Messer LLC (EUC)	Yes
Praxair, Inc. (EUC)	Yes
The Procter & Gamble Paper Products Co. (EUC)	Yes
Trustees of the University of Pennsylvania (EUC)	Yes
Wellsboro Electric Company (ED)	Yes

Susan Bruce represents the PJM Industrial Customer Coalition and 12 PJM members that supported the joint stakeholders' EOL proposal. | © *RTO Insider*

The stakeholders garnered 64% support for the proposal in a sector-weighted vote in the MRC, then 62% on a procedural vote to bring the matter before the Members Committee — both short of the two-thirds threshold required.

The stakeholders felt more confident heading into the June 18 vote, after addressing what

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they said was misinformation about their proposal.

One stakeholder said some members were concerned the proposal would "mess up" the interconnection queue. Others were told TOs "couldn't replace a pole without going to the stakeholders."

"There were a lot of things that were being said about our proposal that weren't entirely accurate," Tatum said. "We talked to a lot of folks to make sure they had an unbiased view of the facts and the focus."

Getting out the Vote

"It really did require a lot of listening on our part … to address the concerns" that caused the failed May vote, said Susan Bruce, who represents the PJM ICC. "You had to do old school get-out-the-vote discussions."

"In the last four or five years, I can't think of more grassroot-level voting calls than I received on this issue," one stakeholder said. "I had folks on both sides reaching out to me. … There was almost none of that before the prior [May] vote."

The joint stakeholders gained 21 supporters on June 18 among those absent in May and also won over one member that had abstained. All told, 30 more members voted in June than in May (from 128 to 158), an increase of almost one-quarter.

The joint stakeholders lost six "yes" votes from May: four to abstentions and two to absences. But none of the original "yes" votes joined the TOs in opposition. Meanwhile, four "no" votes switched to "yes," and four other "no" votes abstained.

The stakeholders made big gains among the Generation Owners, picking up six votes to rise from 56.5% of the sector (13 of 23) to 82.6% (19 of 23). Among members of the *PJM Power Providers*, voting affiliates for seven supported the proposal while three members abstained, including two, Advanced Power (voting as Carroll County Energy) and Talen Energy, which had voted "no" in May.

Vistra Energy (voting as Dynegy Marketing and Trade), Eastern Generation and Wheelabrator Falls, which had voted "no" in May, flipped to the "yes" column. The stakeholders also won backing from five generators that hadn't voted in May: Cape May County Municipal Utilities Authority, CPV Power Holdings, Pixelle Specialty Solutions, Tenaska Power Services and NRG Power Marketing.

NRG Energy "supports using competition to control transmission costs in PJM and voted accordingly today with consumer interests and others at the RTO's Members Committee," Travis Kavulla, vice president of regulation for NRG, tweeted after the vote.

By one count, the RTO's renewable generators split with six "yes" votes, three "no" votes and six abstentions. "What happened was the competitive generators all lined up behind the proposal, while the renewable crowd kind of sat on the sideline," one stakeholder involved said.

Financial Traders Side with TOs

The stakeholders also peeled off enough Other Suppliers to squeak out a majority in the sector, rising from 40% in May (14 of 35) to 51% (26 of 51).

They added 12 "yes" votes — including Conoco Phillips, BP Energy and NextEra Energy Marketing, which had abstained or not voted in May, and Direct Energy, which switched from "no" to "yes." The TOs were able to add only four "no" votes.

The joint stakeholders would have cleared the two-thirds threshold at the May MRC meeting had they been able to flip four OS votes. *RTO Insider* reported previously that it was a bloc of financial traders that turned the sector against the stakeholders' proposal in May. (See "Financial Traders Joined TOs in Opposition," *PJM TOs Outline End-of-life Tariff Amendments*.)

Sixteen of 21 financial traders in the OS sector opposed the joint stakeholders, with two voting "yes" and three abstentions. Ten of the companies that voted against the stakeholders are represented by attorney Ruta Skucas of Pierce Atwood.

Several stakeholders noted that financial traders have been at odds with load interests, who have questioned whether the traders bring value to PJM markets.

In 2017, the Financial Marketers Coalition, led by Skucas, vigorously opposed a rule change supported by the PJM ICC and Electric Distributor sector that reduced bidding locations for increment offers, decrement bids and up-to-congestion transactions by almost 90%. (See *PJM MRC OKs Uplift Solution over Financial Marketers' Opposition*.)

In May 2019, the Organization of PJM States Inc. (OPSI) *pressed* PJM to act on a recommendation from the independent consultants' report on the GreenHat Energy default that the RTO conduct a general review of the financial transmission rights market and consider potential reforms. The RTO announced last

Carl Johnson PJM Public Power Coalition	**June Vote**
American Municipal Power (ED)	Yes
Blue Ridge Power Agency, Inc.(ED)	Yes
Borough of Chambersburg(ED)	Yes
Borough of Mont Alto, Pennsylvania(ED)	Yes
Central Virginia Electric Cooperative(ED)	Yes
City of Dover, Delaware(ED)	Yes
Delaware Municipal Electric Corporation, Inc.(ED)	Yes
Easton Utilities Commission(ED)	Yes
Hagerstown Light Department(ED)	Yes
North Carolina Electric Membership Corporation(ED)	Yes
Northern Virginia Electric Cooperative (NOVEC)(ED)	Yes
Old Dominion Electric Cooperative(ED)	Yes
Thurmont Municipal Light Company(ED)	Yes
Town of Williamsport (The)(ED)	Yes
Indiana Municipal Power Agency(GO)	Yes
Madison Gas & Electric Co.(OS)	Yes
WPPI Energy(OS)	Yes
Energy Cooperative Association of Pennsylvania (OS)	Yes
North Carolina Municipal Power Agency Number 1(OS)	Yes
Buckeye Power, Inc.(ED) buckeyepower.com	No
Allegheny Electric Cooperative (ED)	Abstain

All but two of the 21 members of the PJM Public Power Coalition, represented by Carl Johnson, voted for the stakeholders' proposal. | © *RTO Insider*

PJM News

month it will hire a consultant to help it consider whether the FTR and auction revenue rights markets should be changed to ensure more of the benefits go to load-serving entities rather than financial traders. (See *PJM ARR/FTR Review Could Pit LSEs vs. Financial Traders*.)

With that review looming, one stakeholder speculated that the financial traders were engaged in vote trading with TOs. "That's the only conclusion I can come to," the stakeholder said. After the May vote, the stakeholder added, "there was a huge get-out-the-vote effort in the Other Suppliers sector to counter the financial traders."

Skucas declined to discuss her clients' reason for their votes, saying, "I am also concerned and disheartened that a stakeholder could not reach the conclusion that a fellow stakeholder group was substantively weighing disputed issues and reaching a position that differed from their own."

States Supportive

As they had been in May, the Electric Distributor and End-Use Customer sectors were almost unanimous in supporting the joint stakeholders in June. The End-Use Customers sector added two "yes" votes in the June vote (from 17 to 19), remaining unanimous.

Consumer advocates from D.C. and nine of PJM's 13 states — Delaware, Indiana, Maryland, New Jersey, Kentucky, Pennsylvania, North Carolina, West Virginia and Ohio — supported the proposal. Representatives for Virginia, Illinois, Michigan and Tennessee did not vote.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said it is difficult to get participation from all CAPS members for a variety of reasons; some states need more time to obtain voting authority.

Although OPSI took no position on the vote, staff for the New Jersey Board of Public Utilities and the Kentucky Public Service Commission spoke in favor of the proposal at the June MC meeting.

The EOL issue is particularly important for New Jersey, as Public Service Electric and Gas has led all PJM TOs since 2005 in spending on supplemental transmission projects. PSE&G spent $10.3 billion on supplemental projects between 2005 and 2019. Only one other TO, American Electric Power ($7.96 billion), spent more than $4 billion. PSE&G spent more than $5 million on supplemental projects per transmission line circuit mile over the period. Second-ranked Baltimore Gas and Electric spent less than $1.5 million per mile.

Asked to explain the discrepancy, a PSE&G spokesman declined to comment, saying only "we'll pass."

Public Power

The Electric Distributor sector was unchanged at 96.6% in the June vote, with support from all but one of the 29 voting.

All but two of the 21 members of the PJM Public Power Coalition represented by Carl Johnson voted for the stakeholders' proposal. (Most of the coalition is in the Electric Distributor sector; members that don't have load in PJM are registered as Other Suppliers.) Similarly, all nine members of the Public Power Association of New Jersey (PPANJ) voted "yes."

"For the most part, there was support among the public power entities to having PJM do a broader look at replacing facilities that reach their end of life," said Johnson, a consultant for Customized Energy Solutions. "And there was interest in having FERC finally give us a clear determination" on whether its CAISO rulings apply to PJM, he added, saying stakeholders have made convincing arguments on both sides.

PJM has said its role is limited by the two FERC rulings, which concluded that equipment replacements that result in only incidental increases in system capacity are asset management decisions under TOs' exclusive control, not planning matters subject to FERC Order 890. (See *'Asset Management' not Subject to Order 890, FERC Rules*.)

"For us, [transmission] is a very big component of our cost, particularly in the PSEG territory," said Brian Vayda, executive director of the PPANJ. "Transmission is on the verge of overtaking the cost of the commodity on a per-megawatt basis."

Vayda said his members, who serve 75,000 customers, are keenly aware of the importance of reliability and resilience. "But we're very concerned about the escalating costs and the lack of transparency that has always been an issue with supplemental projects."

Margin of Victory

Backers of the joint stakeholders' proposal said they were gratified by the widespread support they received.

"The joint stakeholders put tremendous time and effort into educating stakeholders on the need to push PJM into a grid of the future approach that includes competition and a regional perspective," Poulos said. "It was amazing

Ruta Skucas Financial Traders	June Vote
Financial Traders Represented by Skucas	
Ames Energy, LLC (OS)	No
Big Bend Trading, LLC (OS)	No
BJ Energy, LLC (OS)	No
Boston Energy Group (OS)	No
Dufossat Capital I, LLC (OS)	No
Greene Energy NE LLC (OS)	No
Hexis Energy Trading, LLC (OS)	No
Precept Power LLC (OS)	No
Pure Energy, Inc. (OS)	No
Red Wolf PT, LLC (OS)	No
Taller Cube, LLC (OS)	No
Other Financial Traders	
Appian Way Energy Partners (OS)	No
GBE Energy Marketing (OS)	No
Prime Trading, LLC (OS)	No
Saracen Energy East (OS)	No
Strom Power, LLC (OS)	No
Energia y Servicios del Istmo Centroamericano, (OS)	Yes
Gerdau Ameristeel Energy, Inc. (OS)	Yes
DC Energy (OS)	Abstain
Jersey Green Energy, LLC (OS)	Abstain
Northstar Trading (OS)	Abstain

Sixteen of 21 financial traders in the OS sector opposed the joint stakeholders, with two voting "yes" and three abstentions. Eleven of the companies that voted against the stakeholders are represented by attorney Ruta Skucas of Pierce Atwood. | © *RTO Insider*

PJM News

to see stakeholders rally behind the proposal with only the transmission owners, financial traders and a handful of renewable interests voting against it. On a major issue like this, it is quite impressive to see a unified position from the vast majority of stakeholder interests."

"The key takeaway for me is that a majority of every sector other than the TOs supported the joint stakeholder proposal," ODEC's Adrien Ford said. "That is powerful to me."

"There were 94 companies that voted in support of this. That's a lot of companies," LS Power's Sharon Segner said.

Tatum said the joint stakeholders are eager to have FERC opine on issues that have provoked disagreement among PJM members, including the applicability of the two CAISO orders and the PJM TOs' rights under the OA, Tariff and Consolidated Transmission Owner Agreement (CTOA).

After the June 18 MC vote, AMP Transmission and ODEC filed a motion to have the TOs' Attachment M-3 filing dismissed. They contend the TO's 30-day notice was issued without a formal vote of the TOA-AC, as they say is required by the CTOA. As PJM TOs, AMPT and ODEC have seats on the committee.

Outgoing TOA-AC Chair Takis Laios, of AEP, had said a vote wasn't necessary because a "supermajority" of the TOs had approached him and said they had the votes necessary for a Section 205 filing they wanted to take before stakeholders.

Tatum acknowledged that AMP and ODEC could not have blocked the TOA-AC from approving the Attachment M-3 changes. But had the TOs followed the CTOA rules, Tatum said, "we would have known this was coming."

PJM, TOs: Joint Proposal Violates Rules, Precedent

As in the May votes, the TOs were near unanimous in opposition to the joint stakeholders on June 18 (11 of 13 "no" votes in May to 12 of 14 "no" votes in June). The only defectors were two merchant transmission operators, Linden VFT and Neptune Regional Transmission System, who supported the joint stakeholders.

TO representatives did not respond to requests for comment for this story.

During debates before the MRC and MC, the TOs and PJM said the stakeholders' OA changes violate the CTOA by attempting to give the RTO authority over asset management decisions, making it in the words of Exelon's Robert Taylor "substantively and legally flawed."

In a May 22 *letter*, 10 of the TOs said the joint stakeholders proposal is "not in the best interest of our customers and will impair system reliability and safety." On Friday, the TOs sent PJM a letter insisting it refuse to file the proposal with FERC. (See related story, *TOs Demand PJM Reject EOL Proposal*.)

PJM *said* the joint stakeholders' proposal to amend the definition of supplemental projects and create a new category of EOL projects under the RTO's planning authority "is beyond the scope of authority transferred to PJM under the CTOA."

Alex Stern, director of RTO strategy for PSEG Services, told the MC on June 18 that the TOs spent six months trying to work with other stakeholders only to find "divide and a disconnect" in the stakeholder process. He said the OA changes will hinder, not facilitate, "the grid of the future."

Tatum disagreed. "I honestly believe this is how [the PJM stakeholder process] is supposed to work. There's nothing broken about this in any stretch of the imagination."

He said he has been encouraged by PJM's new CEO, Manu Asthana, who he said has shown a willingness to listen to other stakeholders. "The stakeholder process can work when PJM's fingers are not on the scale," he said.

Erik Heinle, of the D.C. Office of the People's Counsel, said the transmission assets being replaced now were built under different business models — before retail choice, renewable generation, demand response and other innovations.

"We want to see more oversight by PJM. We want to see it fulfill its role as the regional transmission planner.

"PJM has been great about being a leader on the market side. They've been less good about bringing that leadership on transmission," he said. "I am concerned that PJM is not always a neutral player."

Alex Stern, PSEG | © RTO Insider

Greg Poulos Consumer Advocates of the PJM States (CAPS)	**June Vote**
Delaware Division of the Public Advocate (EUC)	Yes
Indiana Office of Utility Consumer Counselor (EUC)	Yes
Maryland Office of People's Counsel (EUC)	Yes
New Jersey Division of Rate Counsel (EUC)	Yes
Office of the Attorney General, Kentucky (EUC)	Yes
Office of the People's Counsel for D.C. (EUC)	Yes
Ohio Consumers' Counsel (EUC)	Yes
Pennsylvania Office of Consumer Advocate (EUC)	Yes
Public Staff - North Carolina Utilities Commission (EUC)	Yes
West Virginia Consumer Advocate Division (EUC)	Yes
Illinois Citizens Utility Board (EUC)	Absent
Michigan Department of Attorney General (EUC)	Absent
Tennessee Consumer Advocate & Protection Division (EUC)	Absent
Virginia Office of Attorney General (EUC)	Absent

Consumer advocates from D.C. and nine of PJM's 13 states supported the proposal. Four did not vote. | © RTO Insider

Asked to respond, PJM referred to General Counsel Chris O'Hara's comments at the June 18 meeting — at which he said the RTO would file the OA changes with FERC although it disagrees with them — and the Board of Managers' May 27 *letter* to the joint stakeholders defending PJM's EOL proposal.

"These issues will be ultimately settled at the FERC," said spokeswoman Susan Buehler. ■

PJM News

FERC Rules Against Anbaric in OSW Tx Order

By Michael Yoder

FERC on June 18 denied a complaint filed by Anbaric Development Partners seeking an order for PJM to allow developers of offshore transmission "platforms" the ability to obtain injection rights.

The commission ruled that Anbaric failed to demonstrate that the PJM Tariff is unjust and unreasonable because of the RTO's refusal to allow three proposed offshore transmission projects to receive transmission injection rights (*EL20-10*).

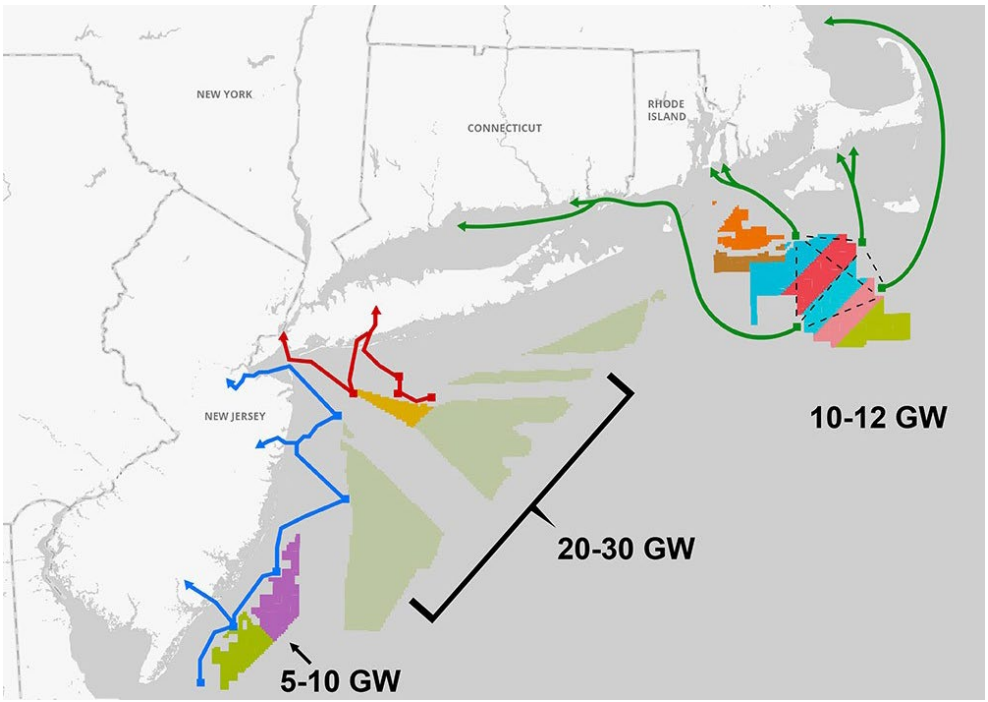
Anbaric and other transmission developers argued to PJM that having individual wind farms build separate radial lines to shore will be more expensive, more environmentally intrusive and less resilient than networked, open-access facilities that multiple wind farms could use.

In its Nov. 18 *complaint*, Anbaric also asserted that PJM's interconnection rules are unduly discriminatory and that its Tariff denies the opportunity to obtain "meaningful and material interconnection rights." (See *Anbaric Seeks FERC Help on OSW Tx*.)

"PJM's interconnection analyses require a source and a sink and controllability in order to meet operational requirements, such as measuring congestion and assessing deliverability," the commission wrote. "Rather than 'picking winners and losers,' these requirements enable PJM to ensure that its transmission system operates reliably and efficiently. Any merchant transmission facilities that meet these Tariff requirements may seek interconnection to the PJM system."

PJM's Tariff allows merchant transmission developers to obtain transmission injection and withdrawal rights for DC facilities or controllable AC facilities connected to a control area outside the RTO. In early 2019, stakeholders approved a problem statement that considered allowing merchant transmission developers to request injection rights for non-controllable AC transmission offshore, but after six special sessions, members opted to refrain from changes. (See "PJM Recommends Sunsetting Offshore Wind Special Sessions," *PJM PC/TEAC Briefs: Sept. 12, 2019*.)

Anbaric — which helped build the 660-MW Neptune HVDC cable linking PJM to Long Island and the 660-MW Hudson project connecting the RTO to Manhattan — filed the FERC complaint after the stakeholder process failed. It is still planning a network of transmission "platforms" that could deliver 52 GW or more of offshore wind generation to PJM, NYISO and ISO-NE. (See *Anbaric Pushes Offshore Grid Plans*.)



Anbaric envisions a network of transmission "platforms" that could deliver 52 GW or more of offshore wind generation to PJM, NYISO and ISO-NE. | *Anbaric Development Partners*

In March 2018, Anbaric submitted interconnection requests for two proposed AC transmission platform projects seeking 1,100 MW of injection rights, but PJM told the company it would need to partner with a generator to obtain the rights under current Tariff rules.

Then in June 2018, Anbaric submitted an interconnection request for a proposed DC transmission platform project seeking a 1,200-MW injection into Public Service Electric and Gas' transmission system in North Brunswick, N.J. After completing a feasibility study that assumed the injection, PJM informed Anbaric in November 2019 that it would only model the project without injection rights.

The company argued to FERC that there are no technical reasons for blocking transmission platform projects, citing transmission built to deliver onshore wind from Texas' Competitive Renewable Energy Zones and California's Tehachapi Pass. FERC dismissed the argument, saying PJM already has the "State Agreement Approach" in its Regional Transmission Expansion Plan process that can be used for transmission to offshore wind.

The day before it issued its order, the commission issued a *notice* that it will hold a technical conference on Oct. 27 to discuss "whether existing commission transmission, interconnection and merchant transmission facility frameworks in RTOs/ISOs can accommodate anticipated growth in offshore wind generation in an efficient and effective manner that safeguards open-access transmission principles and to consider possible changes or improvements to the current framework should they be needed to accommodate such growth." (See *FERC Announces Tech Conferences on Carbon, OSW*.)

Commissioner Bernard McNamee issued a concurring statement in the Anbaric order saying the technical conference will allow FERC to hear from industry experts about the challenges and opportunities of developing offshore wind projects.

"A key element to gaining access to offshore wind is the construction of and access to transmission to bring wind-generated electricity onshore to the grid," McNamee wrote in his statement. "As discussed in today's order, there are a number of complicated issues involving open access, financing and jurisdiction that need to be confronted." ■

PJM News

Amtrak Complaint Against PPL Rejected by FERC

By Michael Yoder

An Amtrak train stops at a station in Lancaster, Pa.

FERC on June 18 denied a complaint by Amtrak challenging the transmission rates charged to the railroad company by PPL and seeking more than $12.5 million in refunds (*EL19-78*).

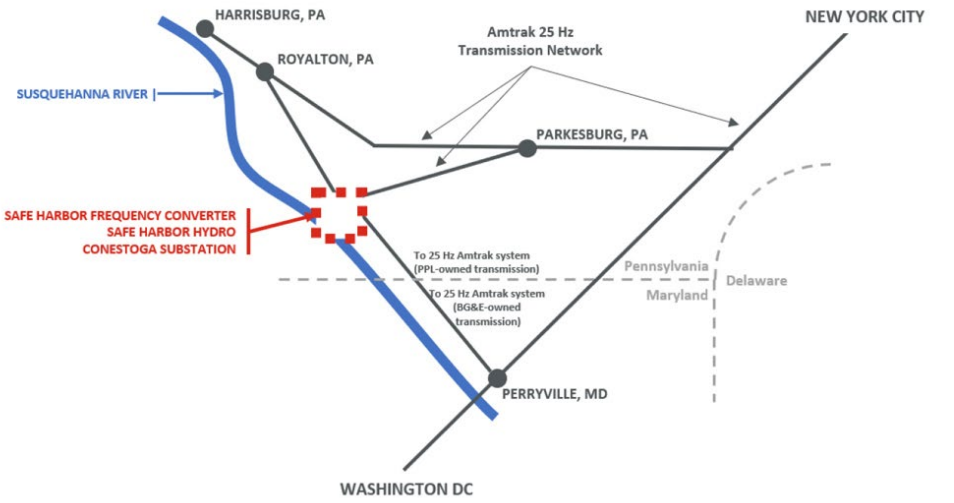
Exelon's Constellation NewEnergy (CNE) supplies electricity to the Amtrak-owned Conestoga substation outside Lancaster, Pa., from or through the nearby Safe Harbor hydroelectric plant, which is directly connected to the substation. Amtrak alleged in its May 2019 *complaint* that it is being assessed "unreasonable" charges by PPL for network integration transmission service (NITS) because no PPL transmission facilities are used to deliver energy to it from Safe Harbor.

PPL, which formerly owned the substation, holds a "floating easement" there, allowing energy generated at Safe Harbor to be delivered to the transmission system to serve third parties. The power needed by the railroad flows through the substation to serve its rail system at Parkesburg and Royalton in Pennsylvania, and at Perryville, Md.

Amtrak complained that PPL's NITS charges for energy delivered from Safe Harbor to Conestoga to serve Parkesburg and Royalton have "no basis in the physical configuration of the substation, operation or Amtrak's consumption patterns."

FERC found that PJM's Tariff provisions applied appropriate NITS charges at the Conestoga substation because Amtrak indicated it receives most of its power from Safe Harbor, which is a network resource.

"Although Amtrak claims that PPL violated the PJM Tariff by calculating Amtrak's Parkesburg and Royalton load based on an unfiled methodology, Amtrak's fundamental argument is that Amtrak should not be charged for NITS for its load at Parkesburg and Royalton if the power Amtrak is supplied by its retail supplier does not flow across PPL's transmission facilities," the commission wrote, saying that the railroad is seeking transmission services "that are inconsistent with the PJM Tariff and commission policy."



Map of Amtrak service at Conestoga | *FERC*

Amtrak also acknowledged that on "rare occasions" when Safe Harbor is unable to meet energy demands, power flows in through PPL's Manor substation on PPL lines, across Safe Harbor's frequency converter and into the Conestoga substation.

FERC responded that having a backup power source "is what it means to take and rely on network service" and that a transmission provider like PPL "plans and provides for firm transmission capacity sufficient to meet the customer's current and projected peak loads."

"Given these benefits, it is appropriate that Amtrak bears the costs associated with its reliance on the transmission system, as its retail supplier, CNE, is a network customer relying on a network resource," the commission wrote. ■

PJM News

GOP Continues Opposition to Pa. RGGI Plans

By Michael Yoder

Pennsylvania Republican senators said last week that Gov. Tom Wolf's plan to join the Regional Greenhouse Gas Initiative will accelerate the closure of the state's coal-fired generating plants, dealing another economic blow on top of the coronavirus pandemic.

The Senate Environmental Resources and Energy Committee heard from 11 speakers, including a PJM representative, during a two-hour hearing June 23 on Wolf's October *executive order* directing state officials to develop a rulemaking for joining RGGI. Wolf's authority to issue such an order has been challenged by the Republican-controlled legislature. (See *Critics: Pa. RGGI Hearing Stacked with Detractors*.)

Committee Chairman Gene Yaw (R) said joining RGGI will exacerbate the disruption Pennsylvania's energy sector has suffered during the pandemic. "There are many questions that remain with regard to the governor's executive order instructing the Pennsylvania Department of Environmental Protection [DEP] to participate in RGGI," Yaw said.

Yaw and Committee Vice Chairman Joe Pittman (R) led a group of legislators that signed a *letter* in April asking Wolf to rescind his executive order out of "respect for the oversight process," noting the committee had to cancel four public hearings on the issue because of the pandemic.

During the hearing, Pittman grilled DEP Secretary Patrick McDonnell, saying that three coal-fired plants in his district — Conemaugh Generating Station, Homer City Generating Station and Keystone Generating Station — will likely be shut down if the state joins RGGI, causing thousands of job losses.

"I'm not naive to the market conditions," Pittman said. "I recognize the challenges that exist already. But my goodness, allow the market to work. And if you really want us to adjust as communities, then show us the examples of what you're going to do to rectify the damage being done to our communities."

McDonnell said people are "going to be standing outside shuttered plants" within the next 10 years regardless of whether Pennsylvania joins RGGI because of the direction of the energy market. He said utility-scale solar generation is becoming the cheapest resource available within the PJM market and that coal generation is quickly disappearing.

"The reality is the market is driving these decisions," McDonnell said. "The market is driving decisions around moving to renewable energy, clean energy and energy efficiency."

Minority Chairman Steven Santarsiero (D) said he "wholeheartedly" supported Wolf's plan, saying RGGI will allow the state to meet its carbon emission goals and provide economic benefits to residents.

"This is an important change in Pennsylvania policy, and as a consequence, it does require thorough public input and thorough input to this committee as we move forward," Santarsiero said.

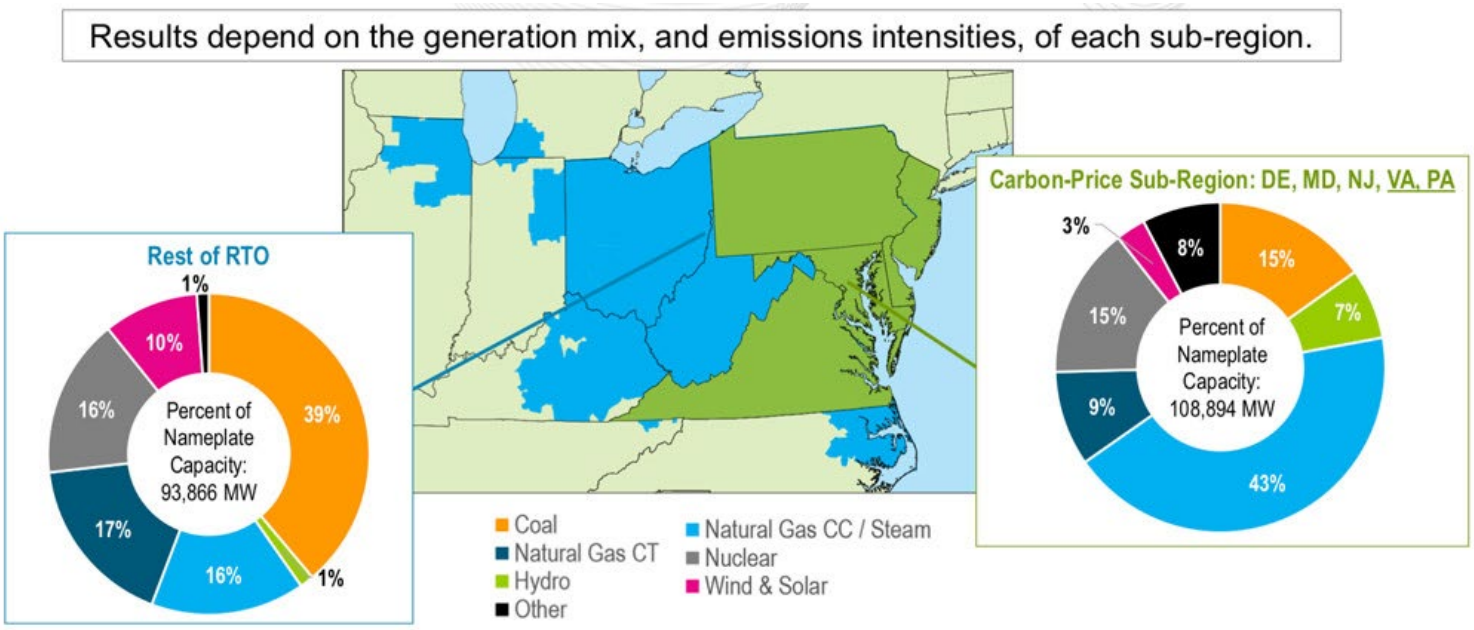
First Climate Goals for Pennsylvania

Reducing CO_2 emissions is a top priority for the Wolf administration. In 2019, according to the DEP, only 5% of Pennsylvania's 231,245 GWh of electricity production were from renewables. Nuclear contributed 36%, natural gas 42% and coal 17%.

In January 2019, Wolf signed an *executive order* setting Pennsylvania's first statewide climate goals: reducing greenhouse gas emissions by 26% by 2025 and by 80% by 2050 compared to 2005 levels.

Wolf followed with a second executive order instructing the DEP to begin the regulatory process to join RGGI. On June 22, citing the pandemic, Wolf provided the department with a six-week extension to deliver a proposed rulemaking to the Pennsylvania Environmental Quality Board, extending the previous July 31 deadline to Sept. 15.

Wolf said RGGI states have reduced power-sector CO_2 pollution by 45% since 2005 while returning $2.31 billion in lifetime energy bill savings to more than 161,000 households and 6,000 businesses that participated in programs funded by RGGI proceeds through its



Generation portfolio mix estimates if Pennsylvania and Virginia join the Regional Greenhouse Gas Initiative | *ISO-NE*

PJM News

first six years of existence.

Hayley Book, senior adviser on energy and climate for the DEP, said Pennsylvania's RGGI implementation date of Jan. 1, 2022, remains in place. Book said the department plans to hold stakeholder and public meetings on RGGI throughout the summer.

RGGI, which includes New York and the six New England states, currently has three PJM states: Delaware, Maryland and New Jersey. Virginia also is planning to join RGGI under the *Clean Economy Act* that passed its legislature in February and goes into effect Jan. 1. (See *PJM Panel Weighs Impact of Pa., Va. Joining RGGI*.)

In her testimony June 23, Gladys Brown Dutrieuille, chairwoman of the Public Utility Commission, said about 24% of the electricity produced in Pennsylvania is exported out of the state. Dutrieuille said the cost of RGGI compliance for exported electricity will be paid by electric customers in the states where that electricity is ultimately used.

PJM Testimony

PJM stakeholder opinions regarding RGGI and carbon pricing have been mixed, with many members encouraging the RTO to take a more active role in facilitating carbon pricing as states decide to join the environmental collective. (See *Stakeholders Urge PJM Action on Carbon Pricing*.)

In a *letter* sent to the PJM Board of Managers on Friday, 29 companies and renewable industry groups called for the RTO to continue its efforts to consider the integration of carbon pricing in its markets.

Stephen Bennett, PJM manager of regulatory and legislative affairs, speaks via video conference at the June 23 Pa. Senate hearing regarding the Regional Greenhouse Gas Initiative (RGGI). | *Pa. Senate*

"With continued and heightened focus by states in the PJM market on reducing carbon emissions from power generation, PJM should continue to work with stakeholders to explore the relative roles that its competitive wholesale markets and state policies should play in shaping the quantity and composition of resources needed to meet such carbon emission reduction goals while cost-effectively meeting future reliability and operational needs," they said.

Stephen Bennett, PJM manager of regulatory and legislative affairs, took a neutral stance on carbon pricing in his *presentation* during last week's committee hearing, but he said, "A price on carbon emissions generally integrates well with PJM's current markets."

PJM's *Carbon Pricing Senior Task Force* has received briefings from RTO staff on its modeling of carbon pricing scenarios and ways to address emissions "leakage" occurring when certain states choose to apply a carbon price and others do not. One of the strongest conclusions drawn from PJM's modeling to date, Bennett said, is that the mix of states included in the carbon pricing region are a "driving factor in determining the overall impact that carbon pricing has on net PJM carbon emissions and electricity prices."

Bennett also reiterated PJM's stance that it does not propose to establish a carbon price and does not take advocacy positions on state legislation.

"PJM recognizes and respects Pennsylvania's prerogative to determine its policies regarding environmental protection and emissions management," Bennett said. "PJM also recognizes that state policy plays a significant role in determining the assets and fuel mix used to meet the state's resource adequacy needs. Rather than advocate, PJM seeks to be a neutral party and provider of factual information on the planning and operation of the bulk electric power system, the operation and evolution of the wholesale power markets that help ensure reliability at the lowest reasonable cost, and the value PJM provides as an RTO."

Chairman Yaw asked Bennett whether PJM will purchase generation from outside of the state if Pennsylvania's generation capability is reduced because of RGGI.

Bennett said one of the biggest benefits of PJM is its geographic diversity, with a market spanning 13 states and D.C.

"If there is a generator or a generation source that has very high cost of prices, they're likely to be displaced either in state or out of state by resources that have a lower cost," Bennett said. "And that's how across the footprint we're able to provide that power at the lowest reasonable cost."

Leakage Concern

Sen. Scott Martin (R) cited PJM's *opportunity statement* on carbon pricing, which said that "without addressing leakage, rising emissions can eliminate the environmental benefits that carbon pricing policies are intended to produce." He asked if environmental benefits touted by the DEP would be offset by other fossil fuel generation units in non-RGGI PJM states, as the department's draft CO_2 trading program regulation contains no provisions to address leakage.

Bennett said he couldn't "categorically" say that any emissions or environmental benefits would be offset, citing the complexity of the modeling PJM has conducted.

"Depending on the cost of carbon and things of that nature, you do have differing outcomes as far as the impact of leakage on the overall net price and emission intensity outcomes," Bennett said. "Leakage is certainly something that can have that impact."

Republican Legislation

The Senate hearing was not meant to be a consideration of Vice Chairman Pittman's Senate Bill *950* or its companion House Bill *2025* sponsored by state Rep. Jim Struzzi (R), which require RGGI to be "vetted through the legislature," though both were mentioned during testimony.

Tom Schuster, clean energy program director for the Sierra Club in Pennsylvania, said SB 950 would prevent Pennsylvania from regulating electric sector carbon pollution and revoke the DEP's existing authority under the Air Pollution Control Act to regulate greenhouse gas emissions in any sector.

Shawn Steffee, executive board trustee and business agent for Boilermakers Local Lodge 154, said he has joined with community, business and labor leaders in the *Power PA Jobs Alliance* to support both the Senate and House bills. Steffee said Pennsylvania coal-fired power plants and older gas plants will lose their ability to compete with similar units in West Virginia and Ohio, two states that are not examining joining RGGI.

"Our plants will abruptly close, and new power generation growth will happen in West Virginia and Ohio, costing us thousands of good paying, blue collar jobs," Steffee said. ■

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TOs Demand PJM Reject EOL Proposal

By Rich Heidorn Jr.

PJM transmission owners demanded Friday that the RTO refuse to submit to FERC the end-of-life (EOL) proposal approved by stakeholders, saying the bid to subject transmission replacement projects to regional planning violates the TOs' rights under the Consolidated Transmission Owners Agreement (CTOA).

After the Members Committee approved the joint stakeholders' EOL proposal with a 69% sector-weighted vote on June 18, PJM General Counsel Chris O'Hara said the RTO would file the proposal with FERC within two weeks, although it believes it exceeds the RTO's authority under the CTOA. (See related story, *Gen. Owners, Other Suppliers Key to EOL Win*.)

"We are at a loss to understand why the board could agree to file a stakeholder proposal when the board itself agrees that the proposal exceeds PJM's delegated authority under the CTOA," the TOs said in a *letter* to the Board of Managers.

"While we understand that one of PJM's duties under section 10.4(xiii) of the Operating Agreement is to file on behalf of PJM members amendments to that agreement and its schedules, that duty is not absolute," the TOs continued. "Since there is no dispute between PJM and the undersigned transmission owners that the stakeholder proposal would require PJM to perform functions and undertake responsibilities that have not been voluntarily transferred to PJM under the CTOA, those commitments outweigh any duty to file the stakeholder proposal under section 10.4(xiii)."

The TOs noted that FERC requires PJM to act independently of its members as well as its TOs. "If that independence is to mean anything, PJM cannot be obligated to file unlawful amendments to the Operating Agreement or its schedules that it acknowledges would give PJM planning authority that transmission owners never voluntarily transferred to PJM. … In short, it is neither sufficient nor appropriate to simply 'let FERC decide.'"

The TOs asked that members of the board or CEO Manu Asthana meet with them to discuss the filing. If PJM does file the proposal with FERC, the TOs said, it should inform the commission of its previously expressed views regarding its planning authority under the CTOA.

The TOs cited PJM staff presentations during the EOL debate and an October 2019 *letter* to members from Dean Oskvig, chair of the board's Reliability & Security Committee, in which he said decisions on when a facility is at the end of its useful life or otherwise needs to be replaced "are the sole responsibility of the transmission owner."

The joint stakeholders insist their proposal honors the TOs' rights by letting them decide when a facility must be replaced — but then allows PJM to incorporate such projects in the Regional Transmission Expansion Plan.

It would require TOs to notify PJM and stakeholders of any facility nearing the end of its life at least six years before its retirement date so the project could be included in five-year planning models and potentially opened to competitive bidding. It would also modify the supplemental project definition to exclude EOL projects, which would become a new category of regionally planned projects. ■

PSEG Kingsland-Hudson reliability project, Kearny, N.J. | *Kiewit*

Company Briefs

Amazon's Carbon Footprint Grew Despite Pledges

Amazon last week admitted its carbon footprint rose 15% last year despite launching initiatives to reduce its harm on the environment.

The company said activities tied to its businesses emitted 51.17 million metric tons of carbon dioxide in 2019. That's up from 2018, when it reported a carbon footprint of 44.4 million metric tons.

Despite the growing numbers, the company also said it's on track to have 100% of its energy use come from solar panels, wind turbines and other renewable energy by 2025. It also pledged to start a $2 billion fund to invest in companies that make products and technology that help combat climate change.

More: *The Associated Press*

Columbia Gas Ordered to Pay $53M over Explosions

A U.S. district court last week sentenced Columbia Gas of Massachusetts to three years' probation and ordered it to pay more than $53 million by July 23 for a deadly gas explosion two years ago in the Merrimack Valley. The fine represents twice the amount of profits the company made between 2015 and 2018 from a pipeline infrastructure program and is the largest criminal fine ever imposed under the Pipeline Safety Act

Last February, the utility agreed to plead guilty in connection with the disaster and be sold by parent company NiSource. Eversource Energy will acquire it for $1.1 billion, and NiSource agreed to forfeit any profit it may earn from the sale.

Federal officials said Columbia Gas "recklessly disregarded" known safety risks and that the company knew they could lead to a "catastrophic event." The explosions killed one man, injured 25 others, set more than 100 homes on fire and displaced 8,000 people.

More: *WBTS*

DTE Energy Vows Net-zero Natural Gas by 2050

DTE Energy last week pledged that its natural gas business will achieve net-zero emissions by 2050 by reducing its greenhouse gas emissions by more than 6 million metric tons a year. The announcement comes 10 months after the company said its electric company will also be net zero by 2050.

CEO Jerry Norcia said DTE's gas company will achieve its goal via a combination of efficiency measures within its operations and the operations of its suppliers, along with efforts to promote more efficient natural gas usage within customers' homes.

The company said it will require its natural gas suppliers to cut their emissions by reducing methane losses that happen while drilling for gas and sealing small "whisper leaks." It will also implement "operational improvements," such as replacing pipes that deliver gas to customers, upgrading engines at its pumping stations, and purchasing "renewable gas" and carbon offsets.

More: *Bridge Magazine*

Ford Aims to be Carbon Neutral by 2050

Ford last week vowed to become carbon neutral by 2050 by focusing on three key sources that make up 95% of its carbon dioxide emissions.

The company will focus on emissions from vehicles, factories and suppliers. The first will be challenging, as 75% (123 million metric tons) of Ford's emissions come from its cars, according to a sustainability report the company released.

Ford has already made progress toward its target, with absolute carbon emissions from its facilities falling by more than 14% in 2019.

More: *The Verge*

Federal Briefs

House Democrats Push for Renewable Aid in New Bills

House Democrats last week included extensions of tax breaks for the renewable energy sector as part of a $1.5 trillion infrastructure package.

The infrastructure bill would extend a tax break for onshore wind developers for five years and to solar developers for six years. It would also allow those companies to receive the credits as direct payments, rather than using them to lower their tax burden. The package includes $70 billion for updating the grid to accommodate more renewable energy, develop a charging network for electric vehicles and improve the efficiency of buildings, among other measures.

Later in the week, Democrats unveiled another package offering tax incentives for renewables, EVs and other environmentally friendly businesses. The legislation would extend several renewable energy tax breaks, including the production and investment tax credits. It would also expand the EV tax credit and create new credits for buyers of used electric cars and manufacturers of zero-emission commercial vehicles and buses.

More: *The Washington Post*; *The Hill*

LNG Rail Shipments Approved

The Pipeline and Hazardous Material Safety Administration has published a final rule allowing rail shipments of LNG despite being opposed by environmental groups and 15 states. The rule will takes effect next month.

The rule will require enhancements, including a thicker outer tank made of steel with a greater puncture resistance, to the approved tank car design.

Pennsylvania and New Jersey were among the protesting states: The Trump administration issued a special permit in December to ship LNG by rail from the Marcellus Shale natural gas fields in Pennsylvania to a yet-to-be-built storage terminal at a former explosives plant in New Jersey. Other states argued the trains will share tracks with passenger trains and travel through congested areas.

More: *The Associated Press*

Nevada, Feds Agree on Plutonium Removal Schedule

The federal government will begin removing

a metric half-ton of weapons-grade plutonium from Nevada starting next year under an agreement between the state and the Department of Energy finalized last week.

Under the settlement, the nuclear material must be completely removed from the National Security Site by the end of 2026. The department also cannot send any more materials from the Savannah River Site in South Carolina without giving the state notice of its intent.

More: *Las Vegas Review-Journal*

Rural Electric Co-ops Get Money to Improve Infrastructure

The U.S. Department of Agriculture last week said it will provide loans and loan guarantees to rural electric cooperatives and utilities to build or improve infrastructure in 21 states. The funding amounts to more than $1.6 billion, including nearly $386 million for investments in smart grid technology.

USDA said more than 9,100 miles of transmission and distribution line will be built or improved because of the funding.

More: *POWER*

Solar Power Costs Falling Faster than Expected

Residential solar power systems prices should fall 17% over the next five years, according to a report from Wood Mackenzie. That is more than the 14% that was expected before the COVID-19 pandemic hit.

The research company also sees commercial systems prices sliding 16%, while utility-scale installations will decline 20%, compared with the prior forecasts of 13% and 16%, respectively, over that period. The steeper declines come as the global economy is expected to shrink by nearly 5% because of the pandemic.

More: *Bloomberg Green*

Chinese-developed Wind Farm Allowed to Proceed

The Committee on Foreign Investment in the United States (CFIUS) last week found that a Texas wind farm being built near the Laughlin Air Force Base does not currently pose a national security concern and will allow it to proceed with construction.

However, GH America Energy, a subsidiary of China-based Guanghui Energy Company, must still mitigate the impact of wind turbines that could interfere with low-level flight training routes. The plans are currently under review in a separate process led by the Air Force and the Defense Department's Military Aviation and Installation Assurance Siting Clearinghouse. Under CFIUS law, the U.S. can put the project under review at any time if there are new developments at the site or if the company does not notify it of changes.

Some have questioned the timing and location of the project and fear it could be used to spy on American troops, disrupt flight routes and give Beijing a foothold in the U.S. grid.

More: *Foreign Policy*

TVA to Give Distributors More Flexibility to Generate Own Power

The Tennessee Valley Authority announced last week it will allow municipal power utilities and cooperatives that distribute its electricity to generate up to 5% of their own power to sell directly to their customers.

TVA said it is offering more flexible power purchase agreements to local power companies (LPCs) that have signed long-term contracts to buy most of their power from it and will now allow its distributors to build their own solar farms and other generating facilities to help serve part of their load. Currently, 140 of 154 LPCs have entered into 20-year agreements with TVA.

"This option empowering local generation adds another avenue to grow distributed and renewable energy resources across the valley," said Doug Perry, TVA senior vice president for commercial energy solutions.

More: *Chattanooga Times Free Press*

Volunteer Electric Soliciting Bids to Replace TVA

The Volunteer Electric Cooperative, which consists of Volunteer Energy and the North Georgia Electric Membership Corp., recently began to solicit requests for proposals to meet their power needs and possibly replace its reliance on the Tennessee Valley Authority.

Volunteer Energy asked energy consulting firm EnerVision to conduct a rate comparison study in 2018 and found that TVA wholesale rates at that time were 28% higher than the average of 10 other neighboring utilities. Another study done by Siemens estimated Memphis Light Gas and Water could save $120 million a year by leaving TVA and generating its own power and turning to other wholesale suppliers.

While most of the 154 local power companies that distribute TVA-generated electricity have looked at their options and signed long-term agreements with the federal utility in the past year, 14 have yet to do so, despite TVA offering a 3.1% discount.

More: *Chattanooga Times Free Press*

State Briefs

REGIONAL

DC PSC Chairman Phillips Elected President of MACRUC

The Mid-Atlantic Conference of Regulatory Utilities Commissioners (MACRUC) last week announced it has selected Willie Phillips, the chairman of the D.C. Public Service Commission, to be its next president.

Phillips, who previously served as first vice president, will serve a one-year term as president. He has an extensive background in the areas of public utility regulation, bulk power system reliability and corporate governance.

MACRUC also announced that Maryland Public Service Commissioner Anthony O'Donnell was elected first vice president and that Gladys Brown Dutrieuille, chair of the Pennsylvania Public Utility Commission, will serve as second vice president.

More: *Maryland Public Service Commission*; *D.C. Public Service Commission*

ARKANSAS

Camden City Council Approves Amended Solar Contract

The Camden Board of Aldermen last week unanimously approved an amended contract with Scenic Hill Solar for the city and water department to buy solar power.

Scenic Hill and the city entered an agreement in May 2019 to build solar facilities, but the project was put on hold because of a lawsuit from Entergy and the Public Service Commission ruling on 1:1 compensation for rooftop power systems. Beginning in 2023, utilities can seek alternative rate structures for net metering. That request must be "in the public interest and ... not result in an unreasonable allocation of, or increase in, costs to other utility customers," the ruling said. However, the facilities built in Camden will be grandfathered in and still receive the metered rating.

More: *Camden News*

CALIFORNIA

Fresno Approves Renewable Energy Plan

The Fresno City Council last week approved a renewable energy plan recommended by Mayor **Lee Brand** that officials claim could save the city $100 million over 20 years.

Storage developer ForeFront Power will provide Fresno with the development, financing, construction and operation of energy storage projects for a 25-MW project. The agreement does not require any upfront costs and will allow the city to benefit from federal tax credits.

More: *The Fresno Bee*

State Mandates Truck Manufacturers to Begin Selling ZEVs

The Air Resources Board last week ordered manufacturers of medium- and heavy-duty commercial trucks to begin selling zero-emission versions of their vehicles in 2024, with 100,000 sold in in the state by 2030 and 300,000 by 2035. The mandate is intended to cut air pollution and reduce greenhouse gas emissions to 40% below 1990 levels by 2030 and 80% below by 2050.

The board will conduct a survey of fleet operators with more than 50 trucks to help determine what additional policies are needed to boost demand. The mandate includes pickups that can haul three-quarters of a ton and semi-trucks that can weigh 80,000 pounds when fully loaded. The board said about 75,000 such trucks are sold each year. Representatives of traditional manufacturers, 95% of whose products are powered by diesel fuel, opposed the mandate and suggested it will be impossible to meet the timeline.

More: *Los Angeles Times*

COLORADO

Colorado Springs to Shut down Coal-fired Plants by 2030

The Colorado Spring Utilities board last week voted to close its coal-fired plants, the Martin Drake Power Plant in downtown Colorado Springs and the Ray Nixon Power Plant south of the city, by 2023 and 2030, respectively. Natural gas turbines will temporarily be placed at the Drake site to provide power until new transmission lines are built.

In January, the Tri-State Generation and Transmission Association said it will close two coal units at its plant in Craig by 2030. A third unit is already set to shut down in 2025. In June, the Platte River Power Authority announced it would close its coal-burning Rawhide Power Plant in 2030. Those closures leave only Xcel Energy with plant retirement dates past 2030.

More: *The Colorado Sun*

ILLINOIS

State's Largest Community Solar Project Comes Online

Summit Ridge Energy last week announced the completion of a 2.7-MW community solar farm built on 15 acres in Fulton County. It is the first such project to come online under Ameren Illinois' Adjustable Block Program and the largest in the state.

Summit Ridge CEO Steve Raeder said the Fulton project represents the first of 36 similar projects being built across the state to come online. When fully constructed, the company's community solar fleet will generate approximately 150 GWh/year.

More: *Solar Power World*

INDIANA

Indiana Michigan Power to Upgrade Grid in Muncie

Indiana Michigan Power announced last week it will invest roughly $9 million to upgrade the grid in Delaware County.

The upgrade involves the construction of a 69-kV underground transmission line in Muncie that will run a half-mile from the Kenmore Substation to existing above-ground lines. Construction is expected to begin in early 2021 and should be completed within a year.

More: *Daily Energy Insider*

MAINE

Solar Projects in Limbo over Net Metering Uncertainty

More than 6,000 ongoing state projects that rely on the benefits of net metering are in limbo as a New England Ratepayers Association (NERA) petition to end the billing practice sits before FERC.

More than 450 organizations, 57,000 individuals and 37 states submitted comments during the public comment period opposing the petition, while 22 organizations and individuals filed support for the proposal. (See *Thousands Oppose Bid to Undo Net Metering*.)

If approved, NERA's petition would shrink the credits solar users receive from utilities by deeming the transactions wholesale instead of retail. This shift would take away states' ability to set their own solar credit standards in favor of giving control to the federal government. In Maine, net metering programs give solar users 100% credit back on the extra energy they produce but don't consume.

More: *Pine Tree Watch*

MICHIGAN

Senators Grill FERC over Dam Failures

State senators last week aggressively questioned FERC employees as part of their investigation into the failure of two dams that caused massive flooding and an estimated $200 million in property damage.

FERC revoked Boyce Hydro's license to generate hydroelectricity at the Edenville Dam in September 2018, at which time the Department of Environment, Great Lakes and Energy (EGLE) assumed regulatory authority. The following month, EGLE hydrologist Jim Pawloski issued a report that

concluded the dam was in "fair structural condition." Sen. Ed McBroom was critical of the decision, saying FERC seemed to possess a "we're washing our hands attitude, we're backing out, it's up to the state now."

FERC's John Katz faced the bombardment and defended the decision by saying, "The sense of the commission was that, rather than having us waving our fingers from Washington, it might be more effective for local authorities who are on the ground and in the project area to improve things."

More: *The Center Square*

MONTANA

2018 Colstrip Problems at Center of NorthWestern Rate Case

The summer-long shutdown of the Colstrip power plant in 2018 was at the forefront last week as NorthWestern Energy made its case to the Public Service Commission for a $23.8 million rate increase to cover unexpected costs when the utility purchased 220,546 more megawatt-hours of electricity than it expected in 2018 and 2019.

The plant's two largest coal-fired generators were taken offline for more than two months during the 2018 summer after tests revealed they were failing the federal Mercury and Air Toxics Standards. During that time, NorthWestern and Colstrip's other utility owners collectively spent more than $20 million on replacement power. Three of those utilities have tried and failed to pass their replacement power costs on to customers by failing to show evidence in Washington state that billing customers was justified. Last week the PSC agreed to exclude several details of the Washington proceedings used to determine whether Montanans should pay most of the replacement costs while allowing others.

More: *Billings Gazette*

Missoula Reaches Agreement with NorthWestern on Clean Energy

The city and county of Missoula last week unanimously approved an agreement with NorthWestern Energy to achieve 100% clean electricity. While the memorandum of understanding does not detail the steps, it inks a baseline agreement to pursue utility-scale renewable energy, improve efficiency and conservation, and modernize the grid.

The costs of implantation will be shared and enable NorthWestern to recover any capital investments. The memorandum also looks to avoid shifting additional costs to customers, unless the costs are approved by the Public Service Commission.

Count Energy and Conservation Coordinator Diana Maneta said 95% of the electricity delivered to the Missoula area is purchased from NorthWestern. Of that, about 60% comes from "clean" sources. Getting to 100% will require replacing the remaining 40% derived from fossil fuels.

More: *Missoula Current*

NEW JERSEY

Holtec Under Criminal Investigation

The Economic Development Authority last week said it is investigating Holtec International, according to a legal brief filed last week in Superior Court in Mercer County. The brief is in response to a lawsuit Holtec filed against the EDA in March for holding up a $26 million payment on its $260 million tax incentive to build a facility in Camden.

"Holtec's misrepresentations — which include its failure to disclose a prior government debarment by the Tennessee Valley Authority for bribing an official of that agency — first came to light during an investigation conducted by the Governor's Task Force on the Economic Development Authority's Tax Incentive Program, and they are now the subject of an ongoing criminal investigation," the brief by attorney Ricardo Solano read.

The brief includes additional references to a "criminal investigation" but does not state which authorities are allegedly investigating the company. Holtec President and CEO Kris Singh said the allegations are "blatantly untruthful" and the company is cooperating with the attorney general's office.

More: *POLITICO*

NEW YORK

NYPA, Signify to Upgrade Streetlights

The New York Power Authority last week announced it has partnered with Netherlands-based Signify to upgrade half a million streetlights.

Smart Street Lighting NY, a state-wide initiative, was launched in 2018 by Gov. Andrew Cuomo and calls for at least 500,000 streetlights to be replaced with energy-efficient LED technology by 2025. The program helps cities reduce their energy consumption and carbon footprint. To date, about 90,000 LED streetlights have been installed or are currently being installed under the initiative.

More: *Cities Today*

Onondaga County Approves New Energy Tax

Onondaga County lawmakers last week voted 10-6 to approve a new 4% residential energy tax that will cost a typical household about $6/month. The tax is effective in September and will end Nov. 30, 2022, unless the legislature renews it.

The vote revives a sales tax on residential energy sales that was collected decades ago but was discontinued in 1982. County Executive Ryan McMahon proposed reimposing the tax to help deal with a projected $100 million budget deficit expected because of the COVID-19 pandemic.

Residential energy sales are exempt from state sales tax, but counties and other jurisdictions have the option to charge customers a local sales tax. More than 50 other counties, cities and school districts in the state currently impose a similar residential sales tax.

More: *The Post-Standard*

NORTH CAROLINA

Duke Creates REC Program for Retail Customers

Duke Energy last week announced it has launched a new program for customers who want to guarantee the electricity they use is renewably generated.

Customers can accept a $3 additional charge to their bill that will go toward supporting the generation of 250-kWh blocks of electricity from renewable resources. Each block is equal to one-fourth of a renewable energy certificate, and there is no limit to how many blocks a customer can purchase in a month. Ninety-five percent of the energy will come from solar projects, while the other 5% will derive from biomass.

More: *pv magazine*

SOUTH CAROLINA

Santee Cooper Extends Executives' Contracts

Santee Cooper's board of directors last

week voted to give CEO Mark Bonsall and Deputy CEO Charles Duckworth each a six-month extension with their current salaries. The two will also be eligible for bonuses depending on their performances.

Under their new contracts, Bonsall and Duckworth will serve with the company until July 2021 and continue to oversee political and legal challenges. Lawmakers have been debating the future of the company since it took on $4 billion in debt in the last decade.

More: *The Associated Press*

VERMONT

Senate Approves Global Warming Solutions Act

The Senate last week voted 22-6 to approve legislation that would legally mandate the state to reduce carbon emissions by 26% below 2005 levels by 2025 and allow individuals to sue the government if it fails to do so. Emissions would also need to be 40% below 1990 levels by 2030 and 80% below by 2050.

While the legislation sets up new reduction requirements, it does not say how the state will meet them. Instead, it will create a 22-member council tasked to come up with a plan by Dec. 1, 2021.

Gov. Phil Scott has not said he would veto the bill, but he has outlined some concerns he has with it.

More: *VTDigger*

WISCONSIN

PSC Approves Xcel's EV Program

The Public Service Commission has approved a new Xcel Energy program that will give customers the option of having the utility install and maintain electric vehicle charging stations in their homes

or businesses.

Upon deciding they would like a charging station, the customer would ask the utility to install an EV charger and either pay upfront or over time. Xcel Principal Rate Analyst Tyrel Zich said the program lowers the cost for ratepayers to charge EVs because it uses "smart charging equipment" that can be programmed to charge the vehicle during overnight hours when costs are lowest.

It is the second program to receive approval from the PSC, as it approved a pilot program by Madison Gas & Electric as part of a rate increase several years ago.

More: *Wisconsin Public Radio*