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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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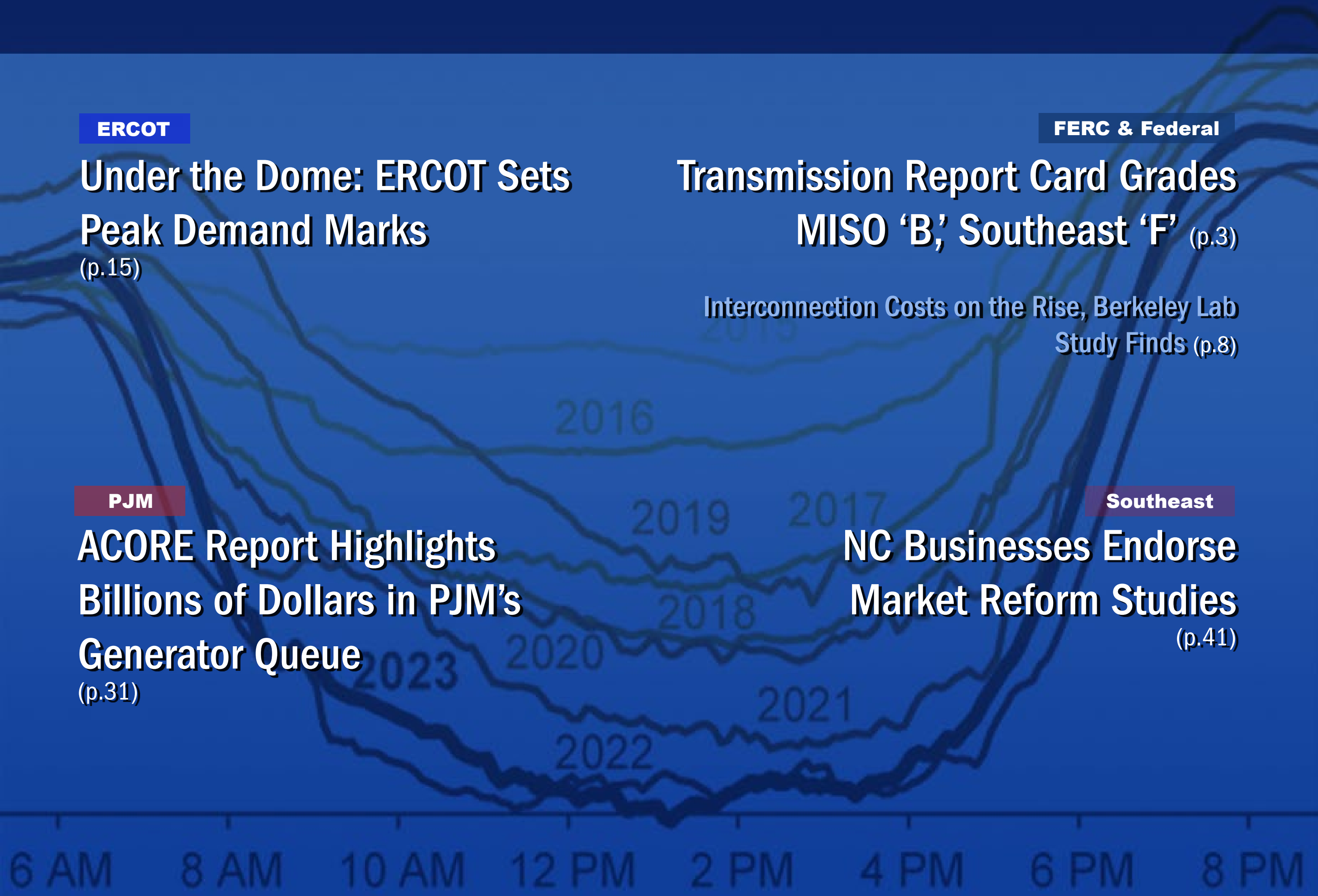

COVER: The drop in net load in the middle of the day has increased as solar capacity in California continues to grow. | *CAISO/EIA*

RTO Insider
Your Eyes and Ears on the Organized Electric Markets
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In this week's issue

Transmission Report Card Grades MISO 'B,' Southeast 'F'

Paper Examines Planning and Results for all Order 1000 Entities

By Hudson Sangree, Tom Kleckner, Amanda Durish Cook, Jon Lamson, John Norris and Devin Leith-Yessian

MISO and CAISO received above-average marks while other regions got middling to failing grades in a "report card" on transmission planning and development published last week by Americans for a Clean Energy Grid.

"Overall the grades leave a lot of room for improvement," ACEG said in its *report*, which it intends to spur discussion about how the FERC Order 1000 transmission planning regions can improve their efforts.

"We hope parties in each region can see positive examples in other ones from which they might learn," ACEG said. "Our intent is not to criticize. Instead, we aim to show that good performance is possible and achievable, and all regions can improve to reach an 'A' grade in the coming years."

The Southeast region has the most room for improvement, "while the West (minus California), Mid-Atlantic (PJM), New England (ISO-NE) and Texas are also lagging in their planning and development efforts," ACEG said.

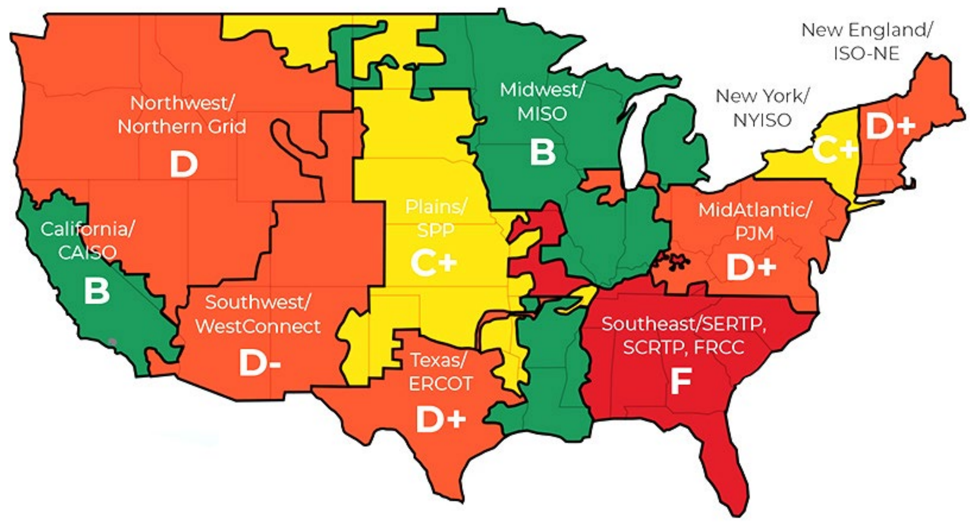
ACEG represents a broad *coalition* of clean energy and conservation groups and companies such as Berkshire Hathaway Energy, Google and NextEra Energy, all "focused on the need to expand, integrate, and modernize the North American high-voltage grid."

In its report, the group said FERC Order 1000 and the commission's other efforts to promote regional planning have produced "lackluster" results.

In response, FERC issued a Notice of Proposed Rulemaking in April 2022 to require long-term regional transmission planning and increased state involvement in transmission cost allocation, among many other changes (*RM21-17*) . (See *Battle Lines Drawn on FERC Tx Planning NOPR*.)

"The NOPR acknowledges that regional planning under Order No. 1000 failed to adequately plan for and meet transmission needs, driven largely by the changing resource mix and increasing load," ACEG said.

ACEG is pleased to see growing recognition of the need for proactive transmission planning, Executive Director Christina Hayes said in a statement accompanying the report. "Without continued improvement, the U.S. grid will remain a barrier to reaching our climate goals, and result in more dangerous power outages that threaten lives and livelihoods."



Overall regional transmission planning grades | *ACEG*

Assessing Transmission Capacity

The "Transmission Planning and Development Regional Report Card" was written by Grid Strategies Research and Policy Manager Zach Zimmerman. Hayes and Grid Strategies President Rob Gramlich helped develop its methodologies and analysis.

The report evaluates the performance of Order 1000 planning regions, not specific entities such as RTOs, because "many parties, besides the planning entities, bear responsibility for performance, including utilities, states, and other stakeholders," it said.

It employs four metrics to grade the regions: planning methods and best practices; miles of transmission built and future transmission plans (i.e., plans that go beyond reliability upgrades); transmission capacity available for new resources; and congestion ($/MWh).

Transmission capacity available for new resources combined three metrics — cost to interconnect, time in queue, and project completion rate — "all of which indicate whether a region's system has sufficient transmission capacity to connect new generation," it said.

"No single metric is entirely dispositive, but in combination, they provide an accurate assessment of transmission capacity," ACEG said.

Based on the criteria, Midwest/MISO and California/CAISO each earned a "B." New York/NYISO and Plains/SPP received grades of "C+." The report card gave "D"s to Mid-Atlantic/PJM, New England/ISO-NE, Texas/ERCOT, Northwest/Northern Grid and Southwest/West Connect. t

The Southeast region — composed of Southeast Regional Transmission Planning (SERTP), South Carolina Regional Transmission Planning (SCRTP) and Florida Reliability Coordinating Council (FRCC) — got an "F."

Midwest/MISO

Transmission planning efforts earned MISO and CAISO their relatively high marks.

ACEG said MISO's "B" grade — and its 86% score, the study's highest — resulted largely from the ISO's work on its 2011 Multi-Value Projects initiative and its first, $10-billion

FERC/Federal News

long-range transmission plan (LRTP) portfolio. The ISO would have received an even higher score if not for MISO South, "where relatively little transmission planning activity occurs," the report said.

MISO said it plans to address system needs in MISO South and to establish stronger connections between its South and Midwest areas in future iterations of its LTRP effort. The grid operator also pointed out that its first LRTP portfolio is "one of the largest transmission portfolios in U.S. history."

"Although we have not had the opportunity to fully review the report, MISO's ranking highlights our continued focus on planning a reliable grid of the future," MISO spokesperson Brandon Morris said in an emailed statement. "This is why transmission evolution is a key pillar of our 'Response to the Reliability Imperative' efforts."

MISO refers to its joint responsibility with its members to ensure that the clean energy transition occurs in a reliable and orderly manner as its "reliability imperative." It issued its latest *report* on those efforts in January.

California/CAISO

CAISO's "proactive, scenario-based, multi value" transmission planning over the past two years accounted for its high score, which at 85.8% nearly matched MISO's.

The report highlights the ISO's work with the California Public Utilities Commission and California Energy Commission to plan collaboratively for the state's clean energy future and coordinate resource procurement and transmission development.

It commended CAISO's inaugural 20-year transmission outlook, approved last year, which examined in-state needs and transmission lines required to import large quantities of wind energy from Wyoming and New Mexico. And it cited the ISO's most recent transmission plan, which broke with CAISO's traditional planning process to bring needed resources online faster while dealing with an interconnection queue that has grown too large and unworkable.

ACEG awarded CAISO an "A-" for its planning efforts but only a "C" for lines planned and built, giving it an overall grade of "B."

"Although it received one of the highest grades with a 'B,' there is still room for improvement," the report said. "California needs to develop the lines it is planning, which could create a congestion-specific metric and provide better public access to good interconnection cost data."

In addition, "California receives a higher grade than most regions for taking a relatively successful and innovative approach to interregional planning," it said.

CAISO's 2021-22 transmission plan noted that the "interregional coordination process [with NorthernGrid and WestConnect] has not met expectations."

As an alternative, "CAISO has implemented programs to enable import transmission from other regions, such as making the TransWest

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
California/CAISO	A-	C	B-	C	85.8%	B
Mid-Atlantic/PJM	D	D	C+	B	67.5%	D+
Midwest/MISO	A-	B-	C+	C	86.0%	B
New England/ISO-NE	D+	D	F	A	68.0%	D+
New York/NYISO	B-	B	F	C	78.6%	C+
Northwest/ Northern Grid	F	C	B-	D	63.3%	D
Plains/SPP	C+	C	C-	C	77.5%	C+
Southeast/SERTP, SCRTP, FRCC	F	F	A-	D	51.9%	F
Southwest/WestConnect	F	B-	B-	D	62.3%	D-
Texas/ERCOT	D	C-	A	D	68.6%	D+

Overall grade and summary of grades for each metric | *ACEG*

FERC/Federal News

Transmission line a part of its balancing authority even though it is not in California, and the cost of the line will be paid for by off-takers," the report said.

TransWest Express, which recently broke ground, will link Wyoming wind to markets in California and the desert Southwest.

"We are pleased that ACEG highlighted the value of this complex effort to develop a vision for what the transmission system will look like in 2040, and appreciative of close cooperation from the California Energy Commission and the California Public Utilities Commission," CAISO Vice President Neil Millar said in a statement to *RTO Insider*.

New York/NYISO

After MISO and CAISO, New York/NYISO was the next highest scoring region with a 78.6% total, earning it a "C+," "based on their transmission planning methods and recently developed plans for new transmission," the report card said.

The grade reflected NYISO's public-policy transmission planning processes, which identify high-voltage transmission projects necessary for New York's transition to clean energy. It also gave NYISO good marks for building projects.

NYISO has a "proactive, scenario-based planning process ... [that] incorporates multiple cases and scenarios over a 20-year evaluation time horizon and uses reliability, economic, and public policy metrics to evaluate projects and select a transmission solution," ACEG said. "For example, New York, in its 2019 public policy transmission plan, studied transmission lines using three scenarios, including a base case, Clean Energy Standard and Retirement Scenario."

"This planning process is why New York is graded relatively well," it said.

New York has also succeeded in getting important transmission projects built, it said. "After many years of little planning, persistent congestion and little transmission, New York has improved dramatically in the last few years," it said. "Significant lines connecting Quebec, upstate, and downstate areas reduced congestion, improved reliability, and achieved public policy goals."

ACEG said that while "NYISO does very little proactive interregional transmission planning," the recent lines, such as those connecting it to Quebec, might signal a more proactive approach.

NYISO's cumulative grade might have been higher except for the "F" ACEG gave it for transmission capacity available for new resources. NYISO deserved the failing grade because New York had by far the slowest completion score (0% compared with 65% for SPP, the next lowest scorer) for getting new resources out of its interconnection queue studies and onto the grid, the report said.

In an email, NYISO responded that "New York has recently seen the most significant investment in new transmission in decades through the NYISO's Public Policy Transmission Planning Process. While the process has been a great success, the NYISO has called for significant additional transmission investment through its Public Policy Transmission Planning Process to support the achievement of public policy requirements."

"The NYISO's System Resource Outlook report from 2022 found that extensive transmission investments will be necessary to deliver renewable energy to consumers and address new constraints from the future addition of new resources," it said.

Plains/SPP

The report card gave SPP a "C+" while saying it has the potential to achieve an "A" if it continues with its planning upgrades.

The report points to SPP's developing consolidated planning process (CPP), which integrates its transmission planning and generator interconnection processes. The CPP's intent is to determine the transmission needed to interconnect new generation, provide transmission service, maintain reliability and resiliency and relieve congestion.

SPP also overhauled its generator interconnection process, instituting a three-phase approach that FERC approved last year, and says it is "aggressively" clearing the queue.

The grid operator currently has 556 projects in its queue, representing 111 GW of capacity; 43% of the proposed projects are solar resources.

According to the report, the Plains region has one of the lower completion rates for new projects, with a capacity-weighted rate of 2% for those entering the queue in 2017 and reaching commercial operation. In 2022, ACEG said SPP received almost triple the interconnection requests compared to their next-highest queue year in 2021.

"This historic queue will likely lead to problems going forward," the report said.

Congestion is increasing in the Plains, thanks to significant curtailment of wind generation in recent years. The RTO's Market Monitoring Unit reported in the 2022 State of the Market that average hourly curtailments increased "substantially" from 244 MW in 2020 to 1,260 MW in 2022.

ACEG credited SPP for its Joint Targeted Interconnection Queue (JTIQ) work with MISO but noted the process is "not necessarily reflective of all planning best practices ... and primarily focused on generator interconnection requests."

SPP could also "better incorporate" merchant developers into its planning, ACEG said.

The JTIQ process has identified 400 miles of projects on the seams valued at over $1 billion in investments, but their cost allocation has yet to be approved. SPP also has almost 700 miles of new lines planned or in development within its near-term and long-range transmission plans, representing a roughly $2 billion investment.

Texas/ERCOT

ERCOT, which delivers about 90% of the state's electricity to 26 million Texas customers, was given one of the report's lower scores, a "D+."

ACEG awarded ERCOT high marks on interconnection but said it needs to address congestion soon.

ERCOT's Independent Market Monitor's 2022 State of the Market report said real-time congestion costs in ERCOT rose 37% last year to $2.8 billion.

Texas' interconnection process uses a "connect and manage" approach to integrated interconnection and transmission planning, the report said. New generators only pay for their connection to the grid, as opposed to the "broader systems or affected interregional system costs that generators in other regions have to pay." The generators don't receive firm transmission rights and grid operators curtail them more quickly, ACEG said.

"However, easy interconnection without proactive planning can lead to congestion and curtailment as significant amounts of generation are added, filling up existing transmission capacity," the report said.

Lawrence Berkeley National Laboratory's

FERC/Federal News

2022 Interconnection Queue report found Texas has the highest project completion rate of any region — 28% of capacity-weighted projects were commercialized — and one of the lowest wait times at 18 months. ERCOT's queue has 902 projects and 250 GW under study, according to the ACEG report.

The report calls for ERCOT to adopt more "proactive, scenario-based, multi value transmission planning."

ERCOT's latest regional transmission plan only identified new lines required for reliability upgrades over a six-year horizon, ACEG said. While Texas did build 2,400 miles of new transmission as part of the 2010-13 competitive renewable energy zones project, those projects are fully subscribed, the report said.

ACEG also said there is a "major need" for interregional transmission in Texas, as was made clear during the deadly 2021 winter storm. In dire need for energy to save a grid that couldn't meet demand, the state was limited in what it could import from its neighbors.

As an islanded interconnection, Texas maintains its jurisdictional freedom from FERC by not mixing its electrons with those of its neighbors.

Legislation following the deadly 2021 winter storm has strengthened the Texas Public Utility Commission's oversight of ERCOT's transmission process. The PUC can direct ERCOT to build certain transmission facilities and a new law has cut the time to approve transmission certifications from 360 days to 180.

New England/ISO-NE

ISO-NE's lack of proactive planning methods led to a low overall score, ACEG said, but the RTO received an "A" on the congestion metric.

ACEG found that transmission planning in New England "has traditionally focused on reliability and been reactive, rather than proactive," noting that a significant buildout of transmission in the early 2000s cut down on congestion, but new resources in remote areas remain constrained. The report also said that ISO-NE would benefit from increased interregional planning.

"New England has done very little to coordinate with New York despite a rapidly growing amount of offshore wind hoping to interconnect close to the seam of both regions," the report said.

In response, an ISO-NE representative highlighted the region's history of making significant transmission investments, including almost $12 billion in grid upgrades since 2002.

"We have and will continue to work collaboratively with the New England states and energy stakeholders to determine how the region can build upon past success as the states look to meet their aggressive climate goals," ISO-NE said.

In June, the New England states, New York and New Jersey, sent a *letter* to the US Department of Energy asking for federal assistance to establish a Northeast States Collaborative on Interregional Transmission, while ISO-NE, NYISO, and PJM supported the proposal in a separate *letter*.

The Collaborative would enable the states to "work in partnership to explore opportunities for increased interconnectivity, including for offshore wind, between our regions."

Mid-Atlantic/PJM

PJM scored poorly in the report, which gave it low rankings for all categories except on its stakeholder process and governance. Its total planning grade was 65%, a letter grade of "D".

ACEG faulted PJM for not considering if transmission proposals could be better addressed through regional projects, not conducting proactive generation and load forecasting and not modeling expected retirements in its 15-year planning period.

While there has been some use of the MISO-PJM Targeted Market Efficiency Process (TMEP), ACEG said interregional planning remains minimal, despite potential benefits related to offshore wind development coordination with the New York and New England regions. Coordination with MISO remains largely limited to operational reliability or short lead-time projects.

The report states that merchant developer proposals are studied through PJM's backlogged interconnection process, which has resulted in FERC complaints about delays.

PJM spokesperson Jeff Shields responded to the report by pointing to the Summer Reliability Assessment released by NERC in May, which found much of the country outside of PJM is at an elevated reliability risk. He said work is already underway on expanding its planning methods as outlined in its Grid of the Future Paper released last year.

He said PJM's queue overhaul, approved by the commission in December, will go into effect this month.

"The reforms will speed up and streamline generation interconnection requests, improve project cost certainty, and significantly improve the process by which new and upgraded generation resources are introduced onto the electrical grid," he said.

Though he argued that PJM has made strides in improving the turnaround for interconnection requests, Shields said many projects that the RTO has completed studies on have yet to be built due to factors beyond its control.

"Today there are 44,000 MW of mostly renewable generation resources that have cleared the PJM study process but have yet to be built. The developers of these projects have everything they need from PJM to move forward with construction, but they are not building. We continue to hear that there are a number of factors unrelated to PJM that are causing delays, including supply chain, siting, regulatory issues or financing," he said.

Northwest/Southwest

In the non-CAISO West, the Northwest/NorthernGrid planning region received a "D" grade, and the Southwest/WestConnect region earned a "D-". Both are Order 1000 regional planning entities ostensibly responsible for grid planning across most of the Western Interconnection.

"NorthernGrid and WestConnect have not conducted proactive planning," ACEG said. "The work of individual utilities or states in the region is much of why the regions managed a 'D' grade."

Both regions received an "F" for planning methods and a "D" for congestion but significantly better grades for transmission capacity for new resources (B-minuses) and transmission lines planned and miles built ("B-" for Southwest/"C" for Northwest.)

"In the Northwest, individual utilities advance much of the significant high-voltage transmission buildout," it said. "PacifiCorp and NV Energy are leading this effort. PacifiCorp's planned transmission lines, known as the Gateway Projects … are an $8 billion investment and over 2,300 miles of new transmission lines."

"NV Energy also has almost 600 miles of new transmission lines known as the Greenlink projects, which are just over $2 billion in investments," it said. "However, NorthernGrid's

2020-2021 transmission plan did not include any interregional or nonincumbent transmission lines."

In the Southwest, WestConnect "did not identify any regional needs in its previous transmission plan," the report said. "States, utilities, and merchant developers are driving most of the transmission planning and development in the region.

"For example, in Colorado, Xcel has planned the Colorado Power Pathway projects, an approximately $2 billion investment in almost 600 miles of high voltage lines that will help Colorado meet its goals by interconnecting 5.5 GW of resources."

"In New Mexico, the [Renewable Energy Transmission Authority] has approximately 1,200 miles of new high voltage transmission under development that will interconnect almost 9 GW of new generation and represents over $5 billion in investments," it said.

Southeast

The Southeast/SERTP, SCRTP and FRCC region came in last with an "F."

"The region makes little information available to the public, has limited opportunities for stakeholders to engage meaningfully and has built and planned minimal regional transmission," the report said.

The region failed under both the planning methods/best practices and transmission lines planned and built criteria. It got a "D" for congestion but came in second in the rankings with an "A-" for transmission capacity available for new resources after scoring 100% for the time that projects spend in its interconnection queue.

In 2021, it took only 18 months from the time an interconnection request was made to the signing of an interconnection agreement in the Southeast. That compared to 51 months in SPP, the longest wait time in the nation.

Lawrence Berkeley's Interconnection Queue report "showed that the Southeast had a queue size similar to NYISO or SPP, with over 800 project requests and around 100 GW of capacity," ACEG said. "For our metrics, the Southeast scored well on completion rates for projects with 16% of projects reaching commercial operation.

"In addition, the Southeast scored well on time projects spent in the interconnection queue," it said. "However, regions without an RTO rely on individual utilities to interconnect resources, and very little aggregated data or transparency exists on those project costs."

'Grades Can Change'

Even the lowest scorers can move up in the rankings, ACEG said in its concluding remarks.

"As with many students that grow over time, these grades can change as regions evolve their planning processes and transmission build out," the report said. "This progress does not strictly depend on compliance with potential new rules from FERC, but on the initiative of the regions and their participants in enhancing their planning processes and building much-needed high-capacity regional transmission."

"Future report cards will watch closely for improvement and look forward to regions moving to the head of the class," it said. ■

FERC/Federal News

Interconnection Costs on the Rise, Berkeley Lab Study Finds

Analysis Finds Costs Vary by Technology

By James Downing

Interconnection costs are on the rise across the U.S., according to a Lawrence Berkeley National Laboratory *analysis* of thousands of projects in five organized electricity markets.

The team manually scraped cost estimates from 2,500 interconnection studies from ISO-NE, MISO, NYISO, PJM and SPP, LBNL policy researcher Joachim Seel said during a webinar Thursday. CAISO has stronger data privacy rules than others, while ERCOT uses a "connect and manage" system that limits the amount of upgrades developers must pay for. Non-RTO regions generally do not release such information.

"Collecting this cost data has been quite difficult as the cost estimates are often the only available interconnection study PDFs, [and] that required time-intensive manual scraping," Seel said. "We've cleaned and sanitized the data and made much of the underlying project cost data available on our website. And to our knowledge, this is really the first time that this data can be easily accessed."

The data collection was partially funded by the U.S. Department of Energy's Interconnection Innovation e-Xchange (i2X) process, said DOE's Cynthia Bothwell, who helps run the exchange created to enable simpler, faster and fairer interconnection of clean energy resources.

"The motivation for the cost analysis that you're going to hear about more today was that we found it very hard to get information," Bothwell said. "Developers said, 'You know, we don't know how much things cost, [or] where we can interconnect, and a lot of other issues."

While the data was public, it was not easy to gather — taking hundreds of worker hours per market to compile. Now the industry will have a central place to look up interconnection cost information, she said.

The LBNL team plans to continue collecting data, including eventually from CAISO and traditionally regulated utilities, and performing additional analyses, Seel said. While costs have been trending up, they vary greatly by project type and other factors, meaning they are "not normally distributed," he said.

"There are many projects with rather low interconnection costs, but also some projects with very high interconnection costs," he said. "And although these high-cost projects may be fewer in number, their high project costs can influence the sample mean quite a bit and pull it upward."

Out of the projects that have made it through PJM's queue since 2017, nearly 120 had interconnection costs of $25/kW, but some were several times higher than that — with a few at $450/kW.

Costs have been on the rise over time, and LBNL broke down projects by complete, pending and withdrawn, with those pulling out of the process having the highest average costs and completed projects the lowest, Seel said.

Newer projects must generally pay for more broad transmission network upgrades triggered by reliability or stability violations found in the modeling of the proposed resource. That could involve reconstruction of high-voltage transmission lines as renewables are often in more rural areas where the grid is weaker.

Breaking Down by Project Type

The analysis also found differences among technologies, with solar costs remaining fairly consistent across regions, and completed projects spending between 5% and 10% of their total capital on interconnection upgrades, while withdrawn projects faced interconnection costs comprising 20% to 40% of their total capex.

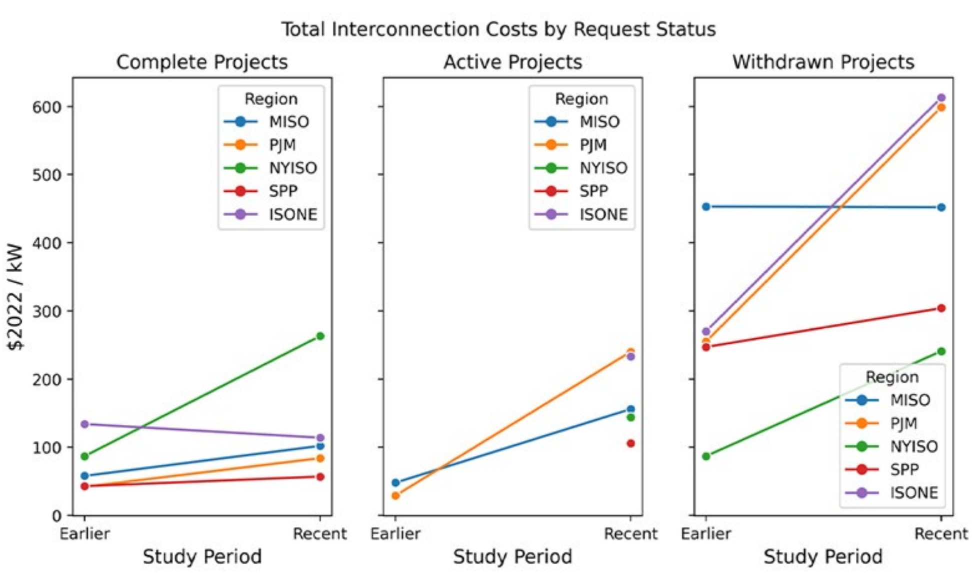
Storage projects also face high costs, which Seel said could be due to their being built in congested parts of the grid to benefit from energy arbitrage opportunities.

Onshore wind has greater variation, with completed projects spending between 3% and 16% of their total budgets on interconnection and withdrawn projects 10% to 40%.

The onshore wind numbers were particularly skewed by ISO-NE, where nearly all proposals since 2018 have withdrawn after facing huge interconnection costs that run up to $800/KW, LBNL's Julie Kemp said.

"For onshore wind, all of the recent projects are located in Maine, and many of them are in quite remote areas where the existing transmission system is pretty limited," said Kemp. "And, so, these high costs that we see are the result of the significant buildup that would be required to connect substantial new generation in these areas that currently do not have much load or much generation."

An LBNL graphic showed the highest interconnection costs for wind in Aroostook County in the state's far north, where the limited transmission system is not even operated by ISO-NE, but rather the Northern Maine Independent System Administrator. ■



| Lawrence Berkeley National Laboratory

FERC/Federal News

FERC Authorizes Final Construction for Mountain Valley Pipeline

James Downing

Construction of the Mountain Valley Pipeline | *Shutterstock*

FERC on June 28 approved Mountain Valley Pipeline's request to move forward with all remaining construction activities, just two days after the pipeline made the request (*CP21-57*).

The commission first approved the Equitrans Midstream project, which runs about 300 miles from West Virginia to southern Virginia, in 2017. But the project was delayed by years of court challenges until Congress passed a provision in the recent debt deal requiring final approvals for the project. President Biden signed the legislation on June 3. (See *Lawmakers, White House Promise More Work on Permitting After Debt Deal*.)

Despite the legal issues, Equitrans says the pipeline, planned to bring shale natural gas to customers in the Southeast, is already 94% complete. A spokesperson said the first of several "forward construction" crews should start work on the right-of-way shortly, with completion expected by the end of the year.

"Mountain Valley looks forward to flowing domestic natural gas this winter," the company said.

FERC said that the new law means that all federal authorizations have been ratified by Congress, which includes issues before it on remand from the D.C. Circuit Court of Appeals in a decision that came down a week before Biden signed the law. (See *DC Circuit Partly Vacates FERC Gasline Approval*.)

The commission specifically authorized the firm to resume construction in the Jefferson National Forest, and across all remaining waterbody crossings.

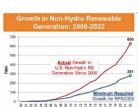
Sen. Joe Manchin (D-W.Va.) has long championed the project and welcomed FERC's approval in a *tweet*, saying that "MVP is vital to America's energy and national security and will benefit not only West Virginia, but the entire nation."

The Sierra Club, which has long opposed the pipeline, released a statement urging regulators to uphold basic environmental safeguards when construction continues.

"Through their own failures alone, the Mountain Valley Pipeline should never be completed," Sierra Club Executive Director Ben Jealous said in a statement. "The unnecessary project has repeatedly been unable to comply with bedrock environmental laws and should never have been used as a tool in must-pass legislation to hold our country hostage or capitulate to special interests willing to destroy the planet for their own profits."

Equitrans stock, which had been trading below $6/share before the debt deal, closed Thursday at $9.55, up 1.8% on the day. ■

National/Federal news from our other channels



States Make Progress Toward Renewable Energy Goals

NetZero Insider

ACEEE Report: Some States not Taking EVs Seriously

NetZero Insider

EPA Launches $7B Solar for All Program

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Report: DER Interconnection in 'Real Disarray' Across US

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FERC/Federal News

FERC Issues Order 898, Changing Its Uniform System of Accounts

Updates Meant to Better Account for Rapidly Evolving Power Industry

James Downing

FERC on Thursday issued Order 898, its final rule updating its Uniform System of Accounts (USofA) to account for rapid changes in technology and the resource mix in the power industry (*RM21-11*).

The changes adopted in the final rule will add functional detail to the USofA to provide uniformity, consistency and transparency in accounting and reporting for investments in renewables and other newer technologies.

The rule creates new subfunctions and accounts for wind, solar and other renewable generating assets. It establishes a new functional class and accounts for energy storage assets. It also creates new accounts and codifies accounting treatment for environmental credits and creates new accounts for computer hardware, software and communication equipment within existing functions that do not already include them.

The new rules also created new accounts and codified the accounting treatment of renewable energy credits.

"By adding functional detail to the USofA, these reforms will provide uniformity, consistency and transparency in accounting and reporting for investments into these assets and assist the commission in fulfilling its responsibilities under the FPA to ensure that rates remain just and reasonable," the order said.

Given the rapid expansion and development of renewable generation, FERC concluded that its accounting system must be changed to better deal with the technologies.

Wind farm near Palm Springs, Calif. | © *RTO Insider LLC*

FERC first proposed the changes in a Notice of Proposed Rulemaking last year and said it largely adopted the proposal with some changes to better reflect its intent, to address the needs of stakeholders and to facilitate solutions to potential technical challenges. (See *FERC NOPRs Would Require 'Candor,' Improved Accounting for Renewables*.)

The USofA goes back to when FERC was called the Federal Power Commission and was meant to facilitate its ratemaking responsibilities and uniformly capture financial and operational information for utilities, and then natural gas pipelines. It has been updated previously to reflect changes in the industry and law, including after the 1990 Clean Air Amendments to account for its creation of sulfur dioxide emissions allowances.

It was also updated 10 years ago in Order 784, which dealt with energy storage technologies, but those changes underestimated the additional burden that functional reporting, along with frequent reclassification of plant assets and associated depreciation, imposes on utilities. The new rules around storage are meant to simplify and improve the recording and reporting of energy storage assets and related expenses.

The USofA already included discrete production accounts for steam, nuclear, hydraulic and other resources, but it did not contain accounts designated for solar, wind or other non-hydro renewable generating assets. Regulated firms used to put their renewable generation in the "other production" accounts, and FERC noted before it issued the NOPR that parties disagreed on whether new accounts would be useful.

But none of the old categories clearly described solar panels, photovoltaic inverters, wind generation towers, or the computer hardware and software required to operate such generators. Related operations and maintenance accounts also failed to uniquely accommodate costs to maintain wind and solar facilities.

USofA accounts also did not explicitly address the purchase, generation or use of RECs, which are similar to the sulfur dioxide emission allowances from the Clean Air Act and previously were included in those accounts. ■

CAISO/West News

California Duck Curve Getting Deeper

Net Load Pushed Below Zero as Solar Power Exceeds Demand

By Hudson Sangree

Increasing solar capacity in California pushed the belly of the state's "duck curve" to new lows this spring, putting stress on the grid and challenging CAISO operators, the U.S. Energy Information Administration said in a *post* last week.

Charting the state's net load — the demand that remains after wind and solar are subtracted — produces the duck curve. Its neck and tail represent times in the morning and evening when demand rises but solar is weak or offline. Its belly represents the middle of the day when abundant solar steeply reduces net load.

From March to May, net load hovered around zero between 12 and 2 p.m. and briefly dipped into negative territory, according to an EIA chart based on CAISO data. That first happened in spring 2022, but the chart shows it occurring more this year. (See *CAISO's New Renewables Record Falls Hair Short of 100%*.)

The deepening duck belly has drawbacks and benefits, EIA said.

"As more solar capacity comes online, conventional power plants are used less often during the middle of the day," it said.

CAISO *statistics* show that solar power peaked on May 23 at more than 15,000 MW, exceeding a 14,000-MW peak in May 2022. (The ISO later saw a new record for solar production of 15,718 MW on June 13.)

That can stress the grid and upend traditional economics, EIA noted.

"The extreme swing in demand for electricity from conventional power plants from midday to late evenings, when energy demand is still high but solar generation has dropped off, means that conventional power plants, such as natural gas-fired plants, must quickly ramp up electricity production to meet consumer demand," it said.

"That rapid ramp up makes it more difficult for grid operators to match grid supply (the power they are generating) with grid demand in real time," EIA said. "In addition, if more solar power is produced than the grid can use, operators might have to curtail solar power to prevent overgeneration."

In addition, the "dynamics of the duck curve can challenge the traditional economics of dispatchable power plants because the factors contributing to the curve reduce the amount of time a conventional power plant operates, which results in reduced energy revenues," EIA said.

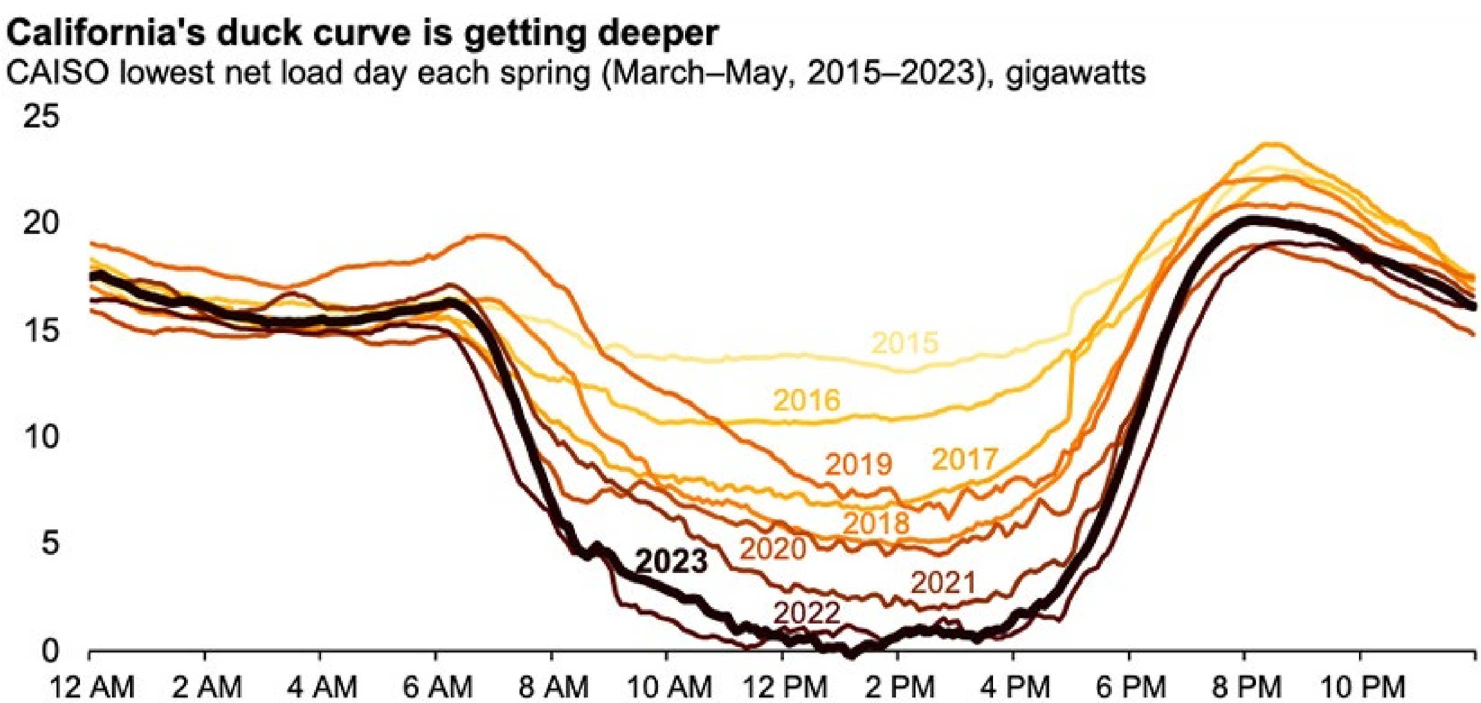
The upside is that the duck curve has "created opportunities for energy storage," EIA said. "The large-scale deployment of energy storage systems, such as batteries, allow some solar energy generated during the day to be stored and saved for later, after the sun sets. Storing some midday solar generation flattens the duck's curve, and dispatching the stored solar generation in the evening shortens the duck's neck."

California has been rapidly adding battery storage to the grid in recent years in response to evening shortfalls.

Battery storage in CAISO has grown from 0.2 GW in 2018 to 4.9 GW in April 2023, and operators plan to add another 4.5 GW in-state by the end of the year, EIA said.

California's experience with the duck curve has been spreading to other areas, including New England, it noted. (See *New England's Duck Curve Days Chart Solar Growth*.)

"In addition, a duck curve is becoming visible at the national level in the United States," EIA said. ■



The drop in net load in the middle of the day has increased as solar capacity in California continues to grow. | *CAISO/EIA*

CAISO/West News

Calif. Governor, Lawmakers Agree on Infrastructure Bills

One Bill Would Streamline Energy, Transportation Project Review

By Hudson Sangree

One of Gov. Gavin Newsom's infrastructure bills would make it easier to remove Joshua trees, iconic desert plants in Southern California, to make way for development. | *Shutterstock*

California Gov. Gavin Newsom and legislative leaders reached an agreement last week on most parts of Newsom's package of infrastructure bills intended to hasten clean energy development and improve grid reliability.

"We are accelerating our global leadership on climate by fast-tracking the clean energy projects that will create cleaner air for generations to come," Newsom said in a joint statement with Senate President pro tempore Toni Atkins and Assembly Speaker Anthony Rendon announcing the deal.

The bills they agreed on include *Senate Bill 149*, which would streamline judicial review of certain clean energy and transportation projects by requiring that challenges to the projects under the California Environmental Quality Act (CEQA) be resolved by the courts within 270 days, including lawsuits and appeals. (See *Newsom Stresses Role of Permitting in Calif. Energy Transition*.)

Some environmental groups strongly opposed weakening CEQA protections.

The compromise between Newsom and lawmakers exempted from the streamlining provisions a highly controversial proposal to convey water from Northern to Southern California via a tunnel under the Sacramento-San Joaquin Delta.

Another measure, *Assembly Bill 122*, would allow but mitigate the removal of western Joshua trees, iconic California desert plants that the state Fish and Game Commission is considering listing under the California Endangered Species Act but that occupy large swaths of land slated for utility-scale solar arrays and battery storage.

Other measures include:

- *AB 124*, which would authorize the California Infrastructure and Economic Development Bank and the state Department of Water Resources to use funding from the federal Inflation Reduction Act to finance projects that reduce greenhouse gas emissions.
- *AB 126*, which would extend funding for the state's Clean Transportation Program and the Air Quality Management Program through Department of Motor Vehicle fees and require an annual funding allocation of 10% for hydrogen refueling stations from the Clean Transportation Program through 2030 or until a sufficient network of refueling stations exist.
- *SB 147*, which would allow the incidental taking of species that are fully protected under the state Endangered Species Act during the construction of infrastructure projects and declassify the peregrine falcon, brown pelican and thicktail chub, a small fish, from the law's list of fully protected species.

On June 27, AB 122 and 124 were read a second time and ordered to a third reading. On Monday, SB 147 and 149 and were in the Senate to consider concurrence with Assembly amendments.

The agreement on the infrastructure bills was part of a larger negotiation between Newsom and lawmakers on the fiscal year 2023/24 budget.

In his budget plan released in January, Newsom proposed slashing $6 billion from the state's $54.3 billion climate commitment because of this year's tax revenue shortfall. (See *Calif. Governor Proposes $6B in Climate Budget Cuts*.)

Lawmakers wanted much of the climate funding restored. The two sides agreed to keep $51.4 billion of the commitment in the budget, reducing it by $2.9 billion.

Newsom signed the budget June 30. ■

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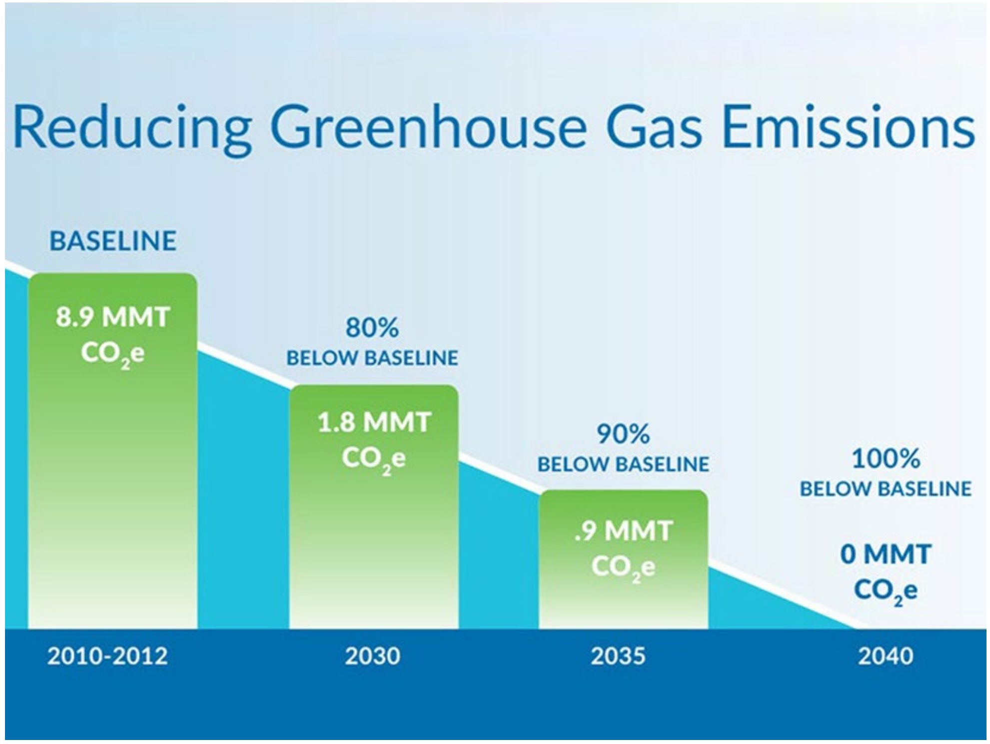
CAISO/West News

PacifiCorp Says It Can Meet Ore. GHG Targets

Utility's IRP, Clean Energy Plan Set 'Pathways' for Zero Emissions for Ore. Customers

By Robert Mullin



PacifiCorp expects to meet Oregon's GHG-reduction mandates by 2030 and 2040, but it will face challenges in doing so. | *PacifiCorp*

PacifiCorp will be able to meet Oregon's ambitious greenhouse gas emissions-reduction targets for electric utilities, but "it will not be without challenges," a company official told state regulators June 27.

Among those challenges is the sheer growth in PacifiCorp's projected demand in Oregon, according to Zepure Shahumyan, the utility's director of energy and environmental policy. The six-state utility expects its Oregon load to increase by 60% by 2030 and 80% by 2040, meaning that growth in absolute emissions will counter progress in reducing per-megawatt-hour emissions.

Shahumyan was among the team of executives presenting PacifiCorp's integrated resource plan (IRP) and inaugural clean energy plan (CEP) to members of Oregon's Public Utility Commission, launching the utility's 2023 IRP process.

PUC Chair Megan Decker noted that it will be the first time the commission will be considering a CEP within an IRP proceeding. CEPs are a new requirement for Oregon utilities, the product of House Bill 2021, which state lawmakers passed two years ago to require electricity providers to reduce their GHG emissions to 80% below a 2010-2012 baseline by 2030, on the path to zero emissions by 2040.

For PacifiCorp, that will mean cutting emissions to 1.8 million metric tons (MMT) of CO_2 equivalent by 2030 from a baseline of 8.9 MMT — and from actual current levels of about 11 MMT. HB 2021 also requires the utility to achieve another reduction to 0.9 MMT in 2035 ahead of the 2040 zero-emissions mandate.

Randy Baker, PacifiCorp's director of resource planning, told the PUC that the 2023 IRP positions the utility to hit those targets. Over the next 20 years, Baker said, PacifiCorp seeks to add 9,111 MW of new wind generation, 8,095 MW of storage resources and 7,855 MW of new solar.

To support that growth in renewables and tap resources located farther inland, the utility also seeks to add more than 1,000 miles of new transmission, including the proposed Boardman-to-Hemingway (B2H) project, to be built in partnership with Idaho Power. Part of the PacifiCorp's Energy Gateway project designed to increase flows between the company's eastern and western systems, the 500-kV B2H line would run for 290 miles from the Boardman substation in Eastern Oregon to the Hemingway substation in Idaho, with additional links expected to grow out from both ends, Baker said.

PacifiCorp's IRP additionally calls for 4,953 MW in capacity savings through energy-efficiency programs and 929 MW saved through demand response.

The PacifiCorp officials presenting last week also acknowledged that meeting the 2040 zero-emission requirement will require adoption of technologies still under development, including 1,500 MW of advanced nuclear generation and 1,240 MW of non-emitting peaking resources. The utility in 2021 agreed to partner with Washington-based TerraPower to build a demonstration Natrium small reactor at the site of a retiring coal plant in Wyoming and last year said it would explore deploying five such plants in its service territory by 2035.

Baker also pointed out that HB 2021 requires that small-scale renewables make up 10% of PacifiCorp's resource portfolio by 2030. Those resources currently comprise 4.6%, leaving PacifiCorp to procure an additional 490 MW by the target year. He told the commission that PacifiCorp has not received as many bids for small-scale projects as it would have liked, and he encouraged developers "to begin the process to identify interconnection costs for projects" ahead of the opening of a request for proposals in April 2024.

'Massive Load Increase'

But the prospect of sharp load growth in Oregon will complicate the way PacifiCorp complies with state emissions targets.

Commissioner Mark Thompson noted that the projected 60% jump in demand by 2030 represents "just a massive load increase in a very short time" and asked what the utility could publicly divulge about the nature of the new load.

"I can't speak much about the load, but I can say it's a large new commercial load that we are forecasting and as part of the planning horizon and planning assumptions for load on our system and in Oregon specifically,"

CAISO/West News

Shahumyan said.

As a result, she said, PacifiCorp will likely need to bring on even more small-scale renewables — beyond the HB 2021 requirement — to prevent serving that load with other emitting resources in the utility's six-state system, which also includes portions of California, Idaho, Utah, Washington and Wyoming.

PacifiCorp's efforts will be further complicated by ongoing changes to its resource mix, part of its push to reduce companywide GHG emissions and reach net zero by 2050. While the utility's IRP calls for retiring much of its coal fleet in the coming years, it plans to convert a handful of coal-fired units to natural gas and operate them until the middle of the next decade. It also plans to upgrade NO_x emissions-reduction equipment at its Hunter and Huntington coal plants in Utah and keep those facilities running until 2042.

All those plants will have to play a diminishing role in providing energy to Oregon because, as Shahumyan pointed out, they will continue to contribute to emissions. But those units will still be part of a PacifiCorp system designed to allocate the costs and benefits of all resources across participating states in a process administered by utility regulators.

To overcome the challenges of meeting Oregon's mandate, PacifiCorp has identified two "pathways," which Shahumyan said are not mutually exclusive.

The first pathway entails managing how gas-fired resources are dispatched until they are replaced by non-emitting peaking technologies.

"Since adding renewables doesn't inherently reduce your emissions, you have to back off thermal emission drivers in order for them to impact our goals under HB 2021," Shahumyan said. "So just flooding the system with renewables by itself won't do it."

The second pathway will require PacifiCorp to engage in multistate negotiations with regulators on how to allocate the costs and benefits of its systemwide resources.

"Under this pathway, we're still allocating our system to Oregon, but we're limiting thermal resource allocation to Oregon," Shahumyan said. By doing that, she noted, the utility reaches its 90% emissions reduction target by 2033, seven years ahead of deadline.

During a public comment period after the PacifiCorp presentation, Mike Goetz, general counsel with the Oregon Citizens' Utility Board, urged the utility to revise its IRP to replace coal with renewables — not new natural gas units.

"Has PacifiCorp truly put forward a least-cost, least-risk plan to benefit Oregon customers while complying with applicable mandates? Or is it simply planning as a system and then layering on HB 2021 requirements?" Goetz said. "On top of that, if PacifiCorp continues to operate thermal units across its system by converting a number of coal plants to gas, how will the cost of these resources be allocated in future years?"

The Oregon PUC is now taking comment on PacifiCorp's IRP and CEP and will hold another public meeting on the plans Aug. 10. ■

ERCOT News

Under the Dome: ERCOT Sets Peak Demand Marks

Unrelenting Heat Expected to Yield More Records this Week

By Tom Kleckner

ERCOT set demand records three times June 27 as demand soared above 80 GW during a sweltering heat wave, breaking a record set last July.

The first mark came during the hour ending at 4 p.m. CT, when ERCOT met an average demand of 80.25 GW. Demand averaged 80.79 and 80.83 GW during the next two hours. All three marks, which are not official, would break the record of 80.15 GW.

The Texas grid operator came within 5 MW of the 2022 record June 26. Preliminary data indicate demand averaged 80.144 GW and 80.137 GW during the hours ending at 5 p.m. and 6 p.m., respectively.

"It's a hellacious week, even by Texas standards," Stoic Energy's Doug Lewin wrote in his most recent *Texas Energy and Power Newsletter*.

The culprit is a heat dome, or high-pressure system, that has been sitting over much of Texas for more than a week now. Meteorologists expect the system to punish Texas for at least another week.

Space City Weather's *Matt Lanza* expects heat index values of 110 to 115 F and said wet-bulb globe temperatures, a measure of heat stress in direct sunlight, will be in the human body's "extreme" level.

Resident golfer Eric Newberry takes a water break during 99-degree temperatures June 27 before finishing 18 holes in Conroe, Texas. | © RTO Insider LLC

"Whatever index you use, it will feel terribly hot all week," he said.

Texas has been under excessive heat warnings since last week, as have parts of New Mexico and the Gulf Coast. Heat advisories are in place from northern Florida to southern New Mexico, affecting more than 46 million people, according to the National Integrated Heat Health Information System.

With the heat dome creating clear skies over much of the state, solar resources again nearly met their summer capacity expectation of 12.6 GW. Wind overperformed in the afternoon of June 27, producing more than 17 GW of energy and combining with solar to account for more than a third of ERCOT's fuel mix. Wind resources have a 10.4-GW summer capacity.

The grid operator set a record for solar production on June 24 at 13.08 GW. It also set a high for weekend peak demand June 25 at 78.97 GW; ERCOT recorded nearly three dozen demand marks last year.

ERCOT issued its second weather watch of the year for most of last week, urging Texans to monitor grid conditions and be prepared to reduce energy use during high-demand periods. It also asked for voluntary conservation measures for four hours on June 20 because of the extreme heat and its forecasted demand. (See "New Grid Notifications Added," *ERCOT Monitor Recommends New Market Design in Report*.)

ERCOT did not respond to a request for comment.

SPP Extends Resource Advisory

The extreme heat also forced SPP to extend a previously issued resource advisory for its entire 14-state balancing authority footprint in the Eastern Interconnection because of expected higher-than-normal generation outages, high demand and uncertain wind forecasts.

The advisory went into effect at midnight CT on June 26, lasting through midnight Saturday. The advisory does not require public conservation but was issued to raise awareness among generators and transmission providers of potential threats to reliability.

The *National Weather Service* said the heat will expand north in Kansas and Missouri and did not expect relief before the Independence Day holiday. ■

ERCOT Briefs

Former EIA Administrator Appointed to Board of Directors

ERCOT said last week that former U.S. Energy Information Administrator Linda Capuano has been appointed to its Board of Directors. Her tenure began Saturday.

Capuano fills the independent director's position left vacant by Zin Smati, who resigned in December over a conflict of interest. (See *ERCOT Board Member Resigns over Business Conflict*.) She has been a faculty member of Rice University's Jones Graduate School of Business since 2015, interrupted by her three-year stint at EIA from 2018 to 2021. Capuano also serves as an adviser to the school's dean on energy initiatives.

She has also previously served on the boards of CAISO (2007-2010) and Peak Reliability (2013-2018). She has a doctorate in materials science and engineering from Stanford University and was a fellow in energy technology at Rice's James A. Baker III Institute for Public Policy from 2014 to 2018.

"Linda's deep energy expertise will be of great value as we continue to strive towards industry-leading reliability and efficient markets," ERCOT CEO Pablo Vegas said in a *press release*.

Capuano joins a board under a *new compensation structure* approved Thursday by the Texas Public Utility Commission. The action increases the independent directors' annual compensation from $87,000 to $160,000, an 83.9% increase. It is the first increase since 2011.

The ISO's eight independent directors are appointed by the state's three-person ERCOT Board Selection Committee, which comprises appointees from the governor, lieutenant governor and the speaker of the House of Representatives. The directors are required by law to not have fiduciary duty or assets in the ERCOT market and must be Texas residents.

Linda Capuano, Rice University | *Rice University*

Renewable resources, like Intersect Power's Brown County Radian Project, produced a record 31.47 GW of power June 27 during the state's heat wave. | Intersect Power

Record Renewables Fill Gap

The Texas grid operator did not see a new high for peak demand June 28, but it did set a record for renewable energy production when wind and solar resources produced a combined 31.47 GW of power at 1:20 p.m. CT, according to *Grid Status*.

"Every megawatt helps," Stoic Energy's Doug Lewin *tweeted*, noting that 9.6 GW of thermal plants were offline at the time. ERCOT defines 8.3 GW as "high outages."

ERCOT set an unofficial peak demand record June 27 when it averaged 80.83 GW during the hour ending at 6 p.m. That would break the old mark of 80.15 GW set last July, the first time its demand was over 80 GW. (See related story, *Under the Dome: ERCOT Sets Peak Demand Marks*.)

The grid operator averaged more than 80 GW during seven interval hours last week.

Gas Plant to Suspend Operations

Talen Energy *notified* ERCOT on June 27 that it plans to indefinitely suspend operations at a gas-fired unit near Corpus Christi, Texas.

The company said Barney Davis Unit 1 will stop operating Nov. 24. The 49-year-old unit has a summer seasonal rating of 292 MW.

Also on June 27, JX Nippon *said* that its Petra Nova carbon-capture facility near Houston will return to service July 15. It had been scheduled to return to operations last Wednesday. The plant has been shut down since 2020, during the height of the COVID-19 pandemic and in the face of slumping oil prices. (See *Carbon-capture Plant Coming Back into Service*.) ■

— Tom Kleckner

ERCOT News

ERCOT Technical Advisory Committee Briefs

New Required Ancillary Service Faces Tight Timeline

ERCOT staff said last week that it faces a tight timeline to add a new ancillary service by Dec. 1, 2024, as required by a recently enacted Texas law.

Texas lawmakers passed a sunset bill (*House Bill 1500*) that includes a directive to ERCOT to develop an uncertainty product called dispatchable reliability reserve service (DRRS). Based on historical variations in availability for each season, the DRRS' criteria require participants to be online and dispatchable for less than two hours after being deployed and to run for at least four hours at their high sustained limit.

Kenan Ögelman, ERCOT vice president of commercial operations, told the Technical Advisory Committee on June 27 that staff are still working through its options, but that the date is "very, very limiting in terms of what we can do."

"The only real chance we have to meet that statutory deadline is to use an existing service, but we are hopeful that maybe stakeholders will have some brilliant idea that we didn't think of," Ögelman said.

The DRRS' objective is to reduce ERCOT's reliance on reliability unit commitments (RUCs), which have soared under the grid operator's conservative operations posture during the last two years. The legislation requires that RUCs be reduced by the amount of DRRS that is procured and that the product be provided by offline resources.

Because ERCOT also uses RUCs for local


ERCOT's Kenan Ögelman explains the obstacles facing the new ancillary service. | *ERCOT*


The Technical Advisory Committee gathers for its June meeting. | *ERCOT*

reliability needs, as required by NERC, Ögelman said RUC reductions can only be achieved when they are not needed to cover load and reserve obligations. He also warned that DRRS' deployment will have implications on prices as its reliance on offline resources means there will be less energy available for dispatch.

"I do think there are going to be things that impact both forward positions and contracts and so forth," Ögelman said.

Given the time constraints, members discussed repurposing other *ancillary services*, including its first new product in more than 20 years, ERCOT contingency reserve service (ECRS), as well as non-spin reserve service. ECRS provides the system with additional capacity that can ramp in 10 minutes to respond to short-term net load ramps, and non-spin offers capacity that can be available in 30 minutes to cover forecast errors or to replace deployed reserves. (See "New Ancillary Service Deployed," *ERCOT Board of Directors Briefs: June 19-20, 2023*.)

Carrie Bivens, who leads ERCOT's Independent Market Monitor, said she was "disheartened" by the discussion of procuring more ECRS and called for a holistic review of ancillary services.

"I like the idea of repurposing non-spin ... so adding more is going to have unintended consequences," she said. "A big portion of the non-spin that gets procured is for six-hour load-forecast uncertainty, and I don't know why you need a 10-minute online product to handle that. I think we have too many megawatts behind the house right now."

Staff plan to schedule workshops in July to solicit broader stakeholder input and continue to evaluate the pros and cons of other alternatives. Discussions with the Public Utility Commission and stakeholders will continue into August, when staff will also begin to develop the protocols. Ögelman said he hopes to bring a recommendation to the Board of Directors in October and secure the PUC's approval in November, giving staff a year to translate the protocols into requirements, develop the software and deploy the product.

"None of this is set in stone," Ögelman said.

Eric Goff, who represents residential consumers, said the uncertainty over the ancillary services market makes it difficult for retailers to determine their charges to consumers.

"The sooner we can resolve this, the better," he said. "The uncertainty could cause problems. This also ties into the importance of the ancil-

ERCOT News

lary services methodology."

Real-time Co-optimization is Back

ERCOT's Matt Mereness told the committee that staff will "blow the dust off everything" in resuming work this week on the real-time co-optimization (RTC) project.

The market mechanism would expand ERCOT's real-time market by clearing energy and ancillary services every five minutes, as most other grid operators already do. However, it has been on hold since the February 2021 winter storm. ERCOT leadership has said RTC's reliability benefits in addressing future operational challenges make the tool a strategic priority.

"The key delivery areas that we have is heads down on [writing] the business requirements [and] getting the band back together," Mereness said. "We're off and running with this program."

Staff and market participants drafted and received approval for eight nodal protocol revision requests (NPRRs) related to RTC before the project was halted. However, a battery task force was unable to complete its work on state-of-charge modeling when dispatching batteries. With batteries expected to be capable of providing 14 GW of energy by 2025 and RTC touching almost every major system, Mereness said, staff and stakeholders will also have to address battery functionality as part of the project's effort.

An updated ERCOT impact analysis has reduced the project's costs down to about $50 million to deploy in 2026, thanks to some hardware savings and "right-sizing" some of staff's efforts.

The RTC's development will begin in April 2024, Mereness said, with the primary risk being maintaining staff availability without interruption during the 3.5-year effort.

"We know this is a squeeze play," he said. "RTC doesn't come in and take over everything; it has to fit in with everything else. But the executive team said, 'Let's do this and keep the foot on the pedal where we can to keep this thing moving forward.'"

7 Revision Requests Pass

TAC unanimously approved a combination ballot that included two NPRRs, two revisions to the nodal operating guide (NOGRRs), an other binding document request (OBDRR), and single changes to the load-profiling (LPGRR) and planning guides (PGRR). If approved by the board, these changes would:

- *NPRR1150*: require qualified scheduling entities (QSEs) that represent resource entities, emergency response service resources or other QSEs, and that receive or transmit wide area network (WAN) data to maintain connections to the ERCOT WAN and a secure private network.
- *NPRR1163* and *LPGRR070*: discontinue the process of evaluating interval data recorder meters to determine whether any are weather-sensitive.
- *NOGRR230*: ensure the WAN data transmission's integrity by requiring data be shared in a manner that prevents denial of service and distributed denial-of-service attacks.
- *NOGRR251*: add cold weather conditions to the template used for developing emergency operations plans to align with *NERC Reliability Standard EOP-011-2* (Emergency Preparedness and Operations).
- *OBDRR045*: edit the demand response data definitions and technical specifications, including modifications to the electric service identifiers list provided to retail electric providers.
- *PGRR103*: require interconnecting entities to complete all conditions for commercial operation of a generation resource or energy storage resource within 180 days of receiving ERCOT's approval for initial synchronization. ■

— Tom Kleckner

ERCOT News

Texas PUC Approves ERCOT Board's 83.9% Pay Increase

Commissioners Say Increase Necessary for Independent Directors

By Tom Kleckner

The Texas Public Utility Commission on Thursday unanimously approved ERCOT's *request* to nearly double compensation for its independent directors, the board's first increase since 2012.

The *order* increases the eight directors' annual compensation from $87,000 to $160,000, an 83.9% increase. It also raises the supplementary compensation for the board chair from $12,800 to $35,000 and from $7,500 to $15,000 for the vice chair. Committee chairs also will now receive an additional $25,000, up from $5,600. (*54444*).

"There have been a lot of changes and a lot has happened at ERCOT over the last decade and we should compensate appropriately," PUC interim chair Kathleen Jackson said during the open meeting.

Commissioner Will McAdams noted that until 2021 legislation removed market participant representatives from the board in favor of independent directors, ERCOT was able to compensate its board at lower levels. Under the new rules, the grid operator's directors are required not to have fiduciary duty or assets in the ISO's market and must divest themselves of energy-related investments.

"That makes this a fairly restrictive framework around finding qualified people who can serve," McAdams said. "In principle, I want a system managed by individuals who can dedicate the time and focus to a grid that is in the midst of [a] most significant energy transition. I believe this will allow us to recruit and retain a dedicated governing body for the system, independent of the industry, which was the legislature's intent and to be able to execute the reforms that we are required to implement along the timetables that we are required to implement them by."

Commissioner Jimmy Glotfelty said he struggled with compensation increases for grid operator executives and their board members, saying comparing their salaries to those of publicly traded companies is not a "correct comparison."

"We have to protect ratepayers ... I just hope that in time, we set this and we leave it. We can't let this be a spiraling issue where costs go unchecked for the consumers of this state," he said before voting in favor of the increase.

Commissioners Lori Cobos and Peter Lake were both absent from the meeting for personal reasons. Lake's term expired Friday.

The ERCOT board and its Human Resources and Governance (HR&G) Committee both approved the increase in June following its annual review of director compensation.

The board hired executive compensation consulting firm Meridian Compensation Partners to perform a benchmarking analysis that analyzed compensation at other ISOs and RTOs, comparably sized general industry companies, ERCOT market participants and other public companies.

ERCOT said the firm consulted with HR&G in making its recommendation, which was based on considerations that included the directors' high volume and complexity of work, recruitment considerations and external optics and standards.

The compensation became effective July 1.

The ISO's eight independent directors are appointed by the state's three-person ERCOT Board Selection Committee, which is comprised of appointees from the governor, lieutenant governor and the Texas House of Representatives' speaker.

The board's non-voting ex officio members — the ERCOT CEO, PUC chair and the Office of Public Utility Counsel's CEO — are not covered by the order.

Recent legislation will increase the board to 12 members in September when a second PUC commissioner becomes an ex officio member. ■

ERCOT stakeholders observe the PUC's June 29 open meeting. | *Admin Monitor*

ISO-NE News

ISO-NE Announces Election of New Board Member

By Jon Lamson

ISO-NE board member Brook Colangelo | *ISO-NE*

ISO-NE announced the election of three candidates to its board last week, including new board member Craig Ivey and the re-election of current board members Brook Colangelo and Mark Vannoy.

Ivey is a former president of Consolidated Edison and is a longtime electricity industry veteran.

"Craig brings extensive expertise in utility operations and a commitment to innovation to the ISO New England Board of Directors," ISO-NE CEO Gordon van Welie said in a press release. "His knowledge will support our mission of ensuring a reliable and efficient regional grid throughout the clean energy transition."

Former president of Con Edison Craig Ivey is the newly elected ISO-NE board member. | *Ameren*

Tasked with overseeing the RTO, the ISO-NE board consists of 10 members serving three-year terms. The nomination process for the board includes current ISO-NE board members, as well as representatives of NEPOOL and the New England Conference of Public Utilities Commissioners. Elected members are prohibited from having a financial stake in the region's wholesale electricity markets.

Ivey will replace retiring board member Roberto Denis in October. Denis previously worked for NV Energy and Florida Power & Light.

Re-elected board member Colangelo will begin his third and final term in October and is currently the chief information officer for Waters Corp.

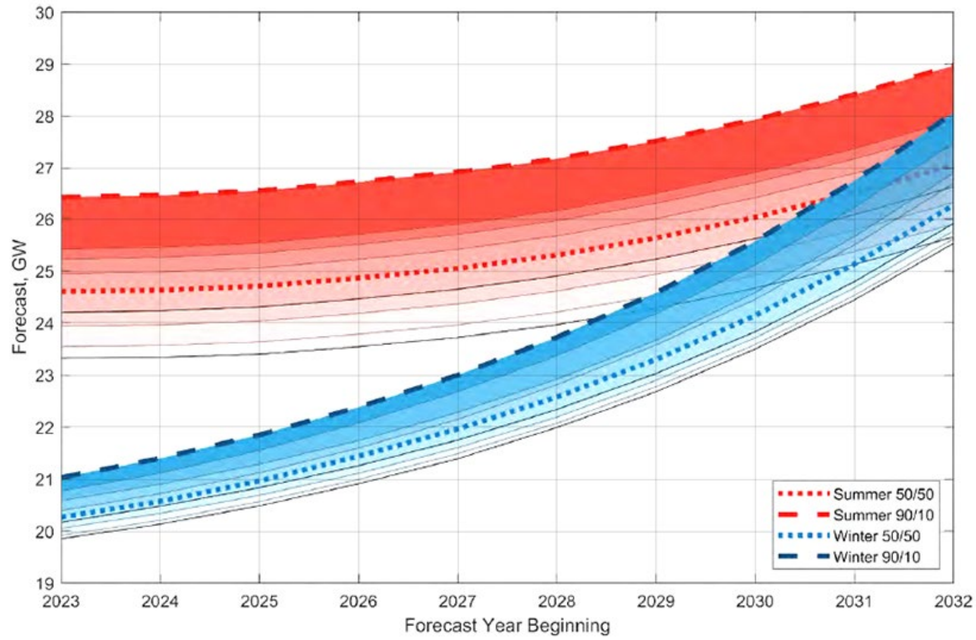
ISO-NE board member Mark Vannoy | *ISO-NE*

Vannoy, president of Maine Water, is entering his second term. He previously served as the chair of the Maine Public Utilities Commission. ■

ISO-NE News

ISO-NE Considers Major Capacity Market Changes

By Jon Lamson



Projected ISO-NE load growth | *ISO-NE*

MANCHESTER, VERMONT — ISO-NE is considering moving to a prompt and seasonal capacity market, the organization told stakeholders at its Participants Committee (PC) summer meeting last week.

The RTO has emphasized the need to address the seasonal variance of resource reliability in its capacity market, especially as it expects to transition from a summer peaking to a winter peaking system. The organization outlined potential options for transitioning to such a market, while also accounting for the implementation of Resource Capacity Accreditation (RCA) updates, which likely would affect the scheduling of future capacity auctions.

The RCA project has been an extended effort by the RTO to better assess the reliability of various resource types, which ISO-NE was hoping to implement for Forward Capacity Auction (FCA) 19, which would procure capacity for the 2028-29 capacity commitment period (CCP).

However, ISO-NE announced in June that it had found an error in the software used in the RCA project, which caused an underestimation of the amount of LNG available to generators when assessing winter risk. The RTO has said this error affected several months' worth of work on the project and will affect its implementation schedule.

In a memo written prior to the PC meeting, ISO-NE Chief Operating Officer Vamsi Chadalavada asked for stakeholder feedback on the best way to incorporate the RCA project into the forward capacity auctions. ISO-NE also highlighted the potential of moving away from the current forward capacity market structure and holding auctions seasonally and just a few months ahead of the CCP.

ISO-NE wrote in the memo that moving to a prompt capacity market would buy time for the RTO to implement the market changes.

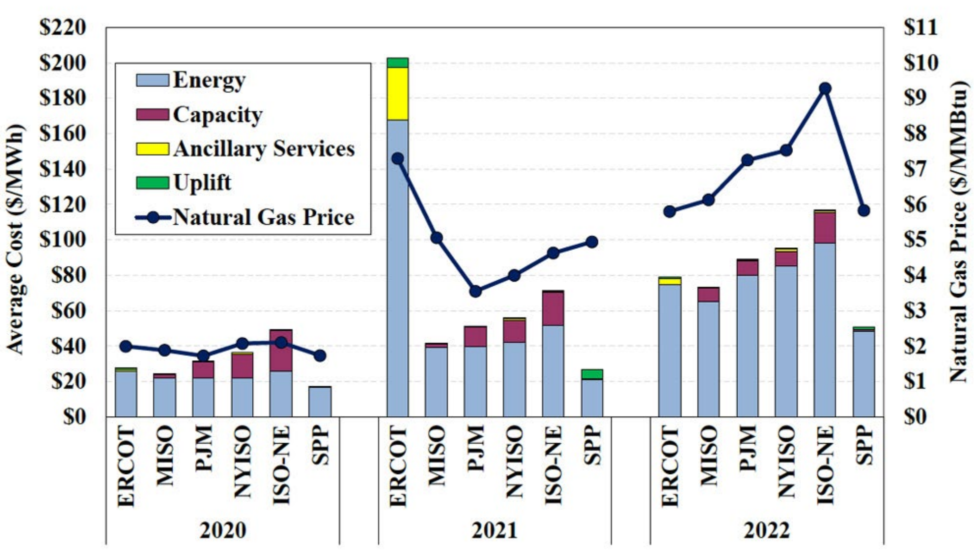
"In transitioning from a three-year forward to a prompt capacity market construct, there will be up to a three-year period between conducting the final forward capacity auction and conducting the first prompt capacity auction," Chadalavada wrote.

David Patton of Potomac Economics, which serves as ISO-NE's external market monitor, recommended transitioning to prompt and seasonal market as soon as feasible and said a seasonal market would do a better job accounting for the differences in seasonal reliability between resources.

Patton said the current process has a "a dubious track record of facilitating entry of new resources," and that procuring capacity three years ahead "inhibits resources with fast development timeframes from receiving revenues as soon as they are able to support reliability."

He noted that the existing FCA structure introduces uncertainty into the expected load and resource mix and added that the current market can also lead to premature retirement of older existing resources.

"Retirement of older units is often prompted by unforeseen equipment failure that is not economic to repair," Patton said. "Such units must accept a capacity obligation that ends more than four years after the FCA, which



Comparison of RTO all-in prices | *Potomac Economics*

ISO-NE News

creates substantial risk for the supplier."

Presenting a cross-market comparison between ISO-NE and other RTOs, Patton found New England had the highest all-in costs in 2022, largely consistent with previous years. Patton said that higher gas prices in the region drive the higher overall costs but added that New England also has the highest capacity charges, largely due to "over-forecasted demand ahead of the FCAs, which are slow to correct."

ISO-NE laid out four potential pathways for implementing the RCA updates as well as a prompt and seasonal capacity auction, including the possibilities of delaying FCA 19, delaying the RCA implementation and/or implementing a prompt and seasonal market along with the RCA changes for either the 19th or 20th auction cycle. The RTO noted that the removal of the Minimum Offer Price Rule will proceed for the 2028-29 CCP as scheduled.

Aleks Mitreski of Brookfield Renewables expressed his opposition to delaying FCA 19 due to the uncertainty this could introduce.

"ISO-NE has a great track record of never delaying an auction, so having FCA 19 run as scheduled will avoid market uncertainty and any regulatory uncertainty if the delay is challenged at FERC," Mitreski said in a statement to *RTO Insider*. "By pushing the RCA implementation for FCA 20, this will give the stakeholders time to evaluate the RCA changes, as well as the benefits and tradeoffs for implementing a seasonal and/or prompt capacity market."

Mitreski added that a move to a prompt and seasonal market would introduce several tradeoffs, and that stakeholders will need time to evaluate the merits of such a change.

"While it will help with the fuel qualification processes for RCA, a prompt market does not enable new entry in the market to address any retirements or transmission issues," Mitreski said. "The only fix for those reliability issues would be expensive out-of-market reliability-must-run agreements like we have seen in NYISO in the past, something that the New England region wants to avoid."

Budget Increase

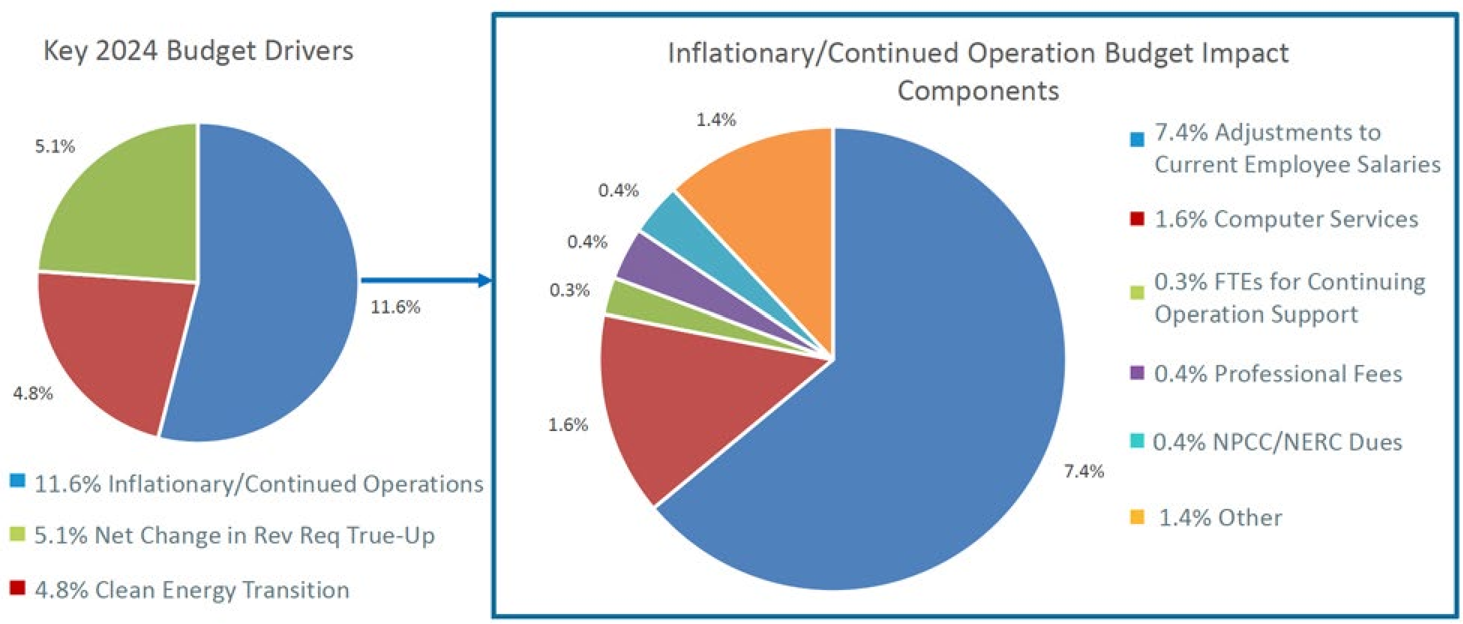
ISO-NE also told the Participants Committee that it expects a significant year-over-year increase for its 2024 budget in its presentation on its preliminary budget for the coming year, equaling a 21.5% increase in the total revenue requirement for 2024.

This increase is driven by increased costs related to preparing for the clean energy transition, effects of inflation on labor and information technology costs, and the net-change from the annual revenue true-up, the RTO said. The largest single portion of the increase is associated with adjustments to employee salaries.

"The 2024 budget represents a ramping-up of organizational capacity to carry out the organization's mission of planning the transmission system, administering the region's wholesale markets, and operating the power system to ensure reliable and competitively priced wholesale electricity; as well as developing new capabilities that will be necessary for supporting the grid of the future," ISO-NE CFO Robert Ludlow said.

Ludlow said that the RTO needs to increase staffing to meet clean energy planning needs, noting that the changing resource mix and the overall increase in generating assets will increase the organization's workload. For 2024, the RTO proposed the addition of 40 new full-time employees, 34 of whom would be focused on supporting the clean energy transition.

"In order to keep pace with the needs of the transition to cleaner generating resources, the ISO must begin ramping up its capabilities and operational capacity now," Ludlow said. ■



ISO-NE preliminary 2024 budget | *ISO-NE*

MISO News

MISO IMM Zeroes in on Tx Congestion in State of the Market Report

By Amanda Durish Cook

MISO's Independent Market Monitor debuted five new recommendations last week as part of his annual State of the Market Report, with multiple suggestions aimed at maximizing transmission utilization by clamping down on wind-related congestion.

"This is going to be one of the most central topics. Congestion is the single most significant operating factor we have to manage," IMM David Patton told the Markets Committee of MISO's Board of Directors on June 28 in a meeting to detail the 2022 *report*.

Patton said the footprint experienced a record $3.7 billion in real-time congestion over 2022, with most of that occurring in the Midwest.

He has said wind generation accounts for almost half of MISO's transmission congestion and that wind resources often aren't motivated to follow MISO's dispatch instructions to reel in output to manage transmission constraints.

He suggested MISO ratchet up its excess and deficient energy deployment penalty charges, which he said are currently not high enough to dissuade generators from deviating from MISO's dispatch instructions.

He said the recommendation stands to address reliability and economic concerns, considering that MISO's unit dispatch system assumes that generators follow instructions and that flows will match dispatch instructions. He said penalties should be based on generators' congestion component of their locational marginal pricing.

"Currently, generators do not accrue excess or deficient energy penalties until they exhibit such deviations for four consecutive intervals. Even after this time, the current penalties do not ensure that generators will benefit by following MISO's dispatch instructions. This is particularly concerning when resources load binding transmission constraints," Patton wrote, adding that if generators are not inclined to follow dispatch instructions, flows over constraints can "substantially exceed" transmission limits.

"We need our markets to motivate people to follow their dispatch instructions," Patton previously said at a June 13 Markets Committee meeting. "If this improves dispatch, it would remove a lot of headaches in the control room."

Patton said MISO has increasingly relied on manual redispatch of resources to manage transmission constraints.

Patton also recommended that MISO expand its transmission constraint demand curves so that its market dispatch system has better control over network flows.

Patton said MISO required "extraordinary operator actions" to manage network flows during storms in 2021 and 2022. He said the current transmission constraint demand curves restrict MISO's market dispatch from managing transmission congestion because the RTO's operating reserve demand curve

NextEra Energy

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MISO News

can prevent the dispatch model from reducing output to manage network flows when transmission and capacity emergencies strike MISO simultaneously. Patton said the value the constraint curve places on managing transmission limitations isn't high enough.

He said MISO operators having to manually dispatch generation to reduce flows on overloaded constraints is "costly and distorts market outcomes."

Patton also said MISO could improve its near-term wind forecasting to recognize inherent principles of wind generation output. He said currently, MISO uses a "persistence" forecast that assumes wind resources will produce the same amount of output as it most recently observed.

"The downside of this approach is that the forecasted output will be predictably lower when output has been increasing and will be predictably higher when wind output is dropping," Patton wrote. He said MISO would cut down on forecast errors if its forecasting recognized recent movement in wind output.

LRTP Doubts

Patton's State of the Market report took an unprecedented foray into transmission planning. He recommended MISO re-examine its future energy mix assumptions behind its ongoing long-range transmission plan (LRTP). Patton said he's concerned that the second of MISO's three, 20-year transmission planning futures includes "unrealistically high levels of intermittent resources and unrealistically low levels of dispatchable, hybrid and battery storage resources."

"The reality is you can't separate transmission planning and markets. … There's an interplay between the decisions resource owners are making on the generation side and the decisions MISO is making on the transmission side," he told MISO board members, who expressed confusion and concern that the IMM would advise MISO on system planning.

Patton said "inefficient investment in transmission" will cause MISO to overlook other solutions to address transmission congestion, including more efficient siting of clean energy resources and investment in new generation, energy storage and grid-enhancing technologies.

MISO is anticipating its members will add 369 GW of mostly wind and solar generation over the next two decades, resulting in a 466-GW system total of nameplate capacity. MISO today operates with about 194 GW. (See *MISO Modeling Line Options for 2nd LRTP Portfolio*.)

Patton said MISO should reconsider its anticipated fleet evolution in its second future, use the most informed capacity expansion and generation retirement assumptions it can, evaluate energy storage alternatives to new lines, and ensure that "any estimated benefits include all of the costs incurred to realize the benefits."

He told board members that if MISO assumes members add overwhelmingly intermittent resources, it will conclude reliability will suffer unless it adds dramatically more transmission. Patton said MISO should recognize that members will likely add energy storage components to renewable energy additions and continue to build natural gas facilities.

"I think we need to take a hard look at Future 2 as the basis before we begin this planning," he said.

Markets Committee members said they must discuss whether it's appropriate for them to consider MISO transmission planning decisions. The System Planning Committee of the MISO Board of Directors typically oversees MISO's transmission planning choices.

Annual Offers in the Seasonal Capacity Market

Finally, Patton turned his attention to MISO's first seasonal capacity auction and said MISO should establish a way for suppliers to submit annual offers and rework some of its 31-day outage limit.

He said an auction that uses only seasonal offer parameters "raises substantial challenges for participants that have annual going forward costs they must cover."

"Suppliers with a resource that requires a capital investment to remain in operation would find it difficult to offer such costs since it will not know how many seasons in which the resource will clear," he explained.

Patton also said MISO's 31-day limit on non-exempt generation outages is causing some distortion in the capacity market because "a number of suppliers" this year deliberately adjusted their longer unit outages, so they straddled seasons, thereby dodging penalties.

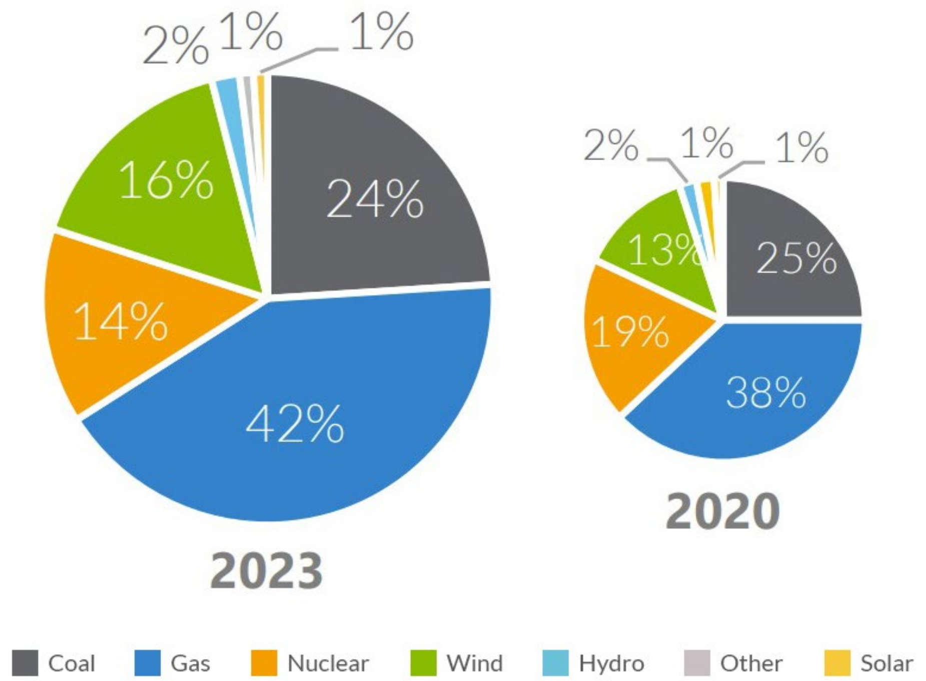
"This can be problematic for outages that are shifted from shoulder seasons into higher-demand winter and summer seasons," Patton said. He said MISO should figure out how it can motivate better outage scheduling.

MISO leadership will respond to Patton's State of the Market report in December. ■

MISO News

MISO Operators Helm Uneventful May

By Amanda Durish Cook



MISO's May 2023 energy fuel mix compared to May 2020 | *MISO*

May in MISO proved no trouble for control room operators.

MISO *averaged* 70 GW of average systemwide load, lower than 2022's 73 GW average. The footprint registered a 102-GW monthly peak on May 31. Operators also noted a 2.8 GW all-time solar peak on May 25, when panels supplied 4.3% of system load at midday.

Real-time locational marginal prices dropped by nearly two-thirds from last May, at $26/MWh, with natural gas prices sliding from about $8/MMBtu to around $2/MMBtu year-over-year. Natural gas generation supplied 42% of the energy mix; coal accounted for 24%, while wind generation and nuclear took a 16% and 14% share, respectively.

MISO recorded an average 55 GW of daily generation outages in May, on par with the same time last year and in 2021.

Meanwhile, MISO has declared its first capacity advisories and conservative operations instructions of the summer. It preemptively *issued* a capacity advisory for June 29 until further notice due to extreme heat indexes in the region. Parts of Louisiana are expected to reach triple-digit heat indexes through the weekend.

The grid operator *called* conservative operations, a capacity advisory and a hot weather alert for MISO South June 26 as the region weathered the continued heatwave. The short-lived warnings were issued and terminated a few hours later in the afternoon.

Earlier, MISO declared conservative operations for northern portions of its footprint on June 22 and 23 due to higher-than-anticipated load and heavy transfers.

MISO is forecasting summer heat to be front-loaded in June. (See *MISO: Little Firm Capacity to Spare This Summer*.) ■

MISO Stakeholders Request JTIQ Cost Containment Measures

By Amanda Durish Cook

Stakeholders pressed MISO to include some form of cost containment measures for it and SPP's Joint Targeted Interconnection Queue portfolio, weeks after the RTOs revealed that the cost estimate for the projects nearly doubled to about $2 billion.

The requests came at a June 27 special meeting to firm up the tariff additions MISO will need to incorporate in the JTIQ study and cost recovery details so it can become a repeatable process.

Stakeholders asked MISO to include some oversight or protections against cost overruns on the transmission projects in its tariff edits. MISO staff said while they've discussed the possibility, at this point they will likely only consider cost protections for future JTIQ portfolios. However, their position became more fluid as the meeting wore on.

MISO and SPP this month announced the costs estimate for the first, five-project JTIQ portfolio of 345 kV lines rose from a little more than $1 billion to nearly $1.9 billion. The larger figure was sent to the Department of Energy under a funding application for the agency's *Grid Resilience and Innovation Partnerships* program. (See *JTIQ Portfolio Cost Estimate Nearly Doubles to $1.9B*.)

MISO staff said for the DOE application, transmission owners included recent inflation and supply chain trends and tried to predict sharper routing and regulatory issues for their projects, raising costs. MISO and SPP have also included administration costs not included in the original JTIQ estimate, including FERC filing costs and costs related to the DOE funding application and federal environmental reviews.

Invenergy's Sophia Dossin said a cap on project costs is important, considering JTIQ cost estimates have almost doubled in two years.

"Even just having a percentage somewhere, even a very high cap that we're sure we're never going to hit at least gives generators some sort of certainty," Dossin said.

Clean Grid Alliance's Rhonda Peters said some type of oversight on costs is "critical." She warned that some generation developers might not go through with projects based on the risks of escalating line costs.

"If that dollar-per-megawatt charge is high right off the bat, this is not going to work. If those costs are in the mid-range and then double, then projects that invested significant capital will not be able to go forward," she said, asking for "some sort of accountability mechanism."

Some stakeholders said the grid operators and transmission owners might be underestimating the effect that stubbornly high inflation will have on the cost of projects.

MISO staff said the JTIQ portfolio can enable an estimated 28 GW of new installed capacity and should give large groups of interconnection customers lowered transmission upgrade costs and more cost certainty than under its previous affected system studies process.

MISO so far has not shared an estimated range of dollar-per-megawatt charges that individual generation projects might face.

"All the buzz around cost caps, is that going to be considered in the tariff language development? ... What's the upper limit where generation developers will not subscribe to these lines?" Southern Renewable Energy Association's Andy Kowalczyk said.

"I wouldn't say anything is off the table. We're listening very carefully to your concerns, and we're going to discuss them internally," MISO counsel Chris Supino said. "If there's a way to include these without disturbing what we're working towards in the tariff, we're going to consider them."

Kowalczyk said contemplating "an upper limit where people are going to bail on lines" is important because load will temporarily pick up the tab on the first JTIQ portfolio if the first batch of lines don't have enough subscribers to be fully funded.

The JTIQ study is designed to focus on backbone projects rather than point-of-interconnection network upgrades. Whereas MISO's and SPP's previous process used actual generation sites in interconnection queues in affected system studies, the JTIQ leans on the likely interconnection spots of future generation representing multiple queue study clusters from both RTOs.

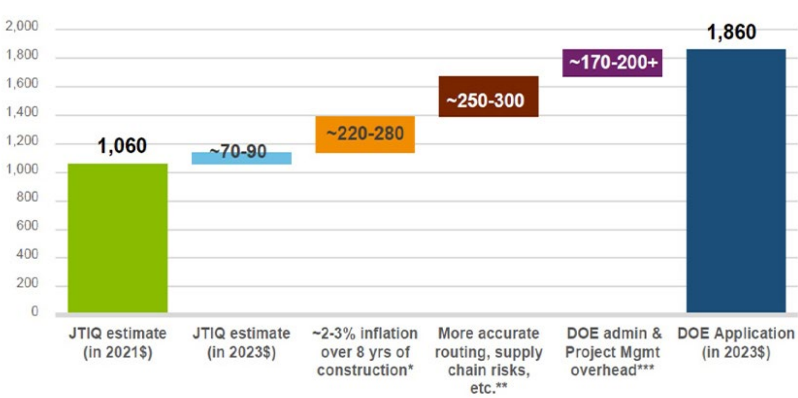
Until now, MISO and SPP have used affected system studies to identify additional, across-the-seam network upgrades the other might need as a result of new generation connecting close to the seam. And while MISO and SPP until now have identified only network upgrades for a particular SPP or MISO study cycle, the JTIQ study is designed to identify larger and longer-term system needs across seams and across groups of generation projects under study.

At this point, MISO considers its proposal to split JTIQ costs 90% to interconnecting generators with the remaining 10% assigned to load final. It will include that cost allocation in tariff edits.

"There is some disagreement, but we believe this course is settled: JTIQ projects meet the definition of generator interconnection projects," Supino said.

Supino said MISO and SPP are discussing whether the projects should be a subcategory of interconnection upgrades, but he said it's undisputed that the JTIQ projects are replacing MISO and SPP's affected system study process and should be allocated 90% to interconnecting generation and 10% to load. As such, he said JTIQ projects won't be open to competitive bidding.

Supino said MISO will include a pledge in its transmittal letter to FERC to evaluate cost allocation changes in future JTIQ portfolios. MISO didn't elaborate on which additional benefits it might consider allocating in the future. ■



Comparison of the RTOs' 2021 JTIQ portfolio cost estimate versus the 2023 estimate contained in the Department of Energy application | *MISO and SPP*

NYISO News

Constellation Gives Details on First-in-nation Pink Hydrogen Production

Lessons are Learned as NY Demonstration Project Continues

By John Cropley

Constellation Energy on June 28 gave an update on the hydrogen production demonstration project at one of its nuclear plants in New York.

The first-in-the-nation production of "pink" hydrogen — generated through electrolysis powered by nuclear energy — began March 7 and is generating data about producing the cleaner-burning gas without generating emissions along the way.

The Nine Mile Point hydrogen project can generate up to 531 kg of hydrogen per day with a 1.5-MW draw: 1.25 MW for the electrolyzer, and 250 kW for its associated equipment.

The two nuclear reactors on site consume only about 80 kg in operation. What to do with the remaining capacity is the subject of a separate demonstration project backed by New York state that is expected to go online in 2025 and explore the potential of hydrogen fuel cells as a long-duration energy storage mechanism.

The electrolyzer project is scheduled to end Oct. 1, four years after it gained conditional approval. Constellation is looking at scaling up operations with the U.S. Department of Energy's National Laboratories to demonstrate how electrolyzers might participate in power markets.

Constellation's Bob Beaumont, who managed the installation of the electrolyzer and associated equipment at Nine Mile Point, gave an update June 28 in a DOE webinar:

- Planning the project was a bowl of alphabet soup: NERC, NYISO, EPA, Nuclear Regulatory Commission and New York Department of Environmental Conservation regulations all had bearing on what was built.
- The project is running just shy of its $14.4 million budget.
- Weekly operations checks take four to five worker hours; quarterly maintenance about 20 worker hours; and annual maintenance about 20 worker hours.
- A quarter mile of cable was needed to power the electrolyzer, and it had to be buried several feet deep because of severe winters.
- The extreme cold — as low as -20 degrees Fahrenheit — caused valves to begin to leak and revealed a need for special sealing materials.
- The potential blast radii of the electrolyzer and the hydrogen storage tank in the event of a lightning strike or terrorist attack had to be evaluated because of the proximity of the two reactors; the system was placed out of the security zone and away from the safety systems. Also, the amount of hydrogen being stored on-site did not change, so a modification of NRC permits was not needed.
- The system was designed to automatically shut down and vent itself if it is hit by seiche waves off Lake Ontario during a storm or after an earthquake.
- The process draws about 2 gallons of water per minute from the local municipal water system, runs it through consumer-grade softeners and carbon filters; and passes it through a reverse osmosis filter and a set of resin filters to reduce its conductivity to the right level; too much conductivity leaves impurities on the membranes, too little thwarts the electrolyzer.

Future Fuel

Hydrogen, which burns without producing greenhouse gas emissions, is potentially a key tool in fighting climate change. It could serve as a form of energy storage and is viewed as an alternative power source for industries and applications that otherwise would be hard to decarbonize.

But the cost of production currently is a barrier to wider use. DOE made reducing that cost by 80%, to $1/kg, the central goal of the first of its *Energy Earthshots* in 2021.

Interest is keen in green hydrogen — derived from renewable resources — because producing greenhouse emissions to generate hydrogen limits the net benefit of burning that hydrogen instead of fossil fuel.

Pink hydrogen is produced with emissions-free nuclear power and, in some processes, with the excess heat generated by nuclear fission.

Beyond hydrogen's potential role in the clean energy transition, operators of boiling-water reactors such as the two at Nine Mile Point use it steadily to prevent corrosion inside the reactors and as a coolant for the rotors on the generators.

Constellation partnered on the Nine Mile Point demonstration project with Nel Hydrogen, manufacturer of the electrolyzer membranes, and the National Renewable Energy, Argonne and Idaho national laboratories.

DOE hydrogen demonstration projects are underway at three other nuclear power stations nationwide. ■

The Nine Mile Point nuclear station is shown in New York. | *Constellation*

NYISO News

NYISO to Comment on State's Cap-and-invest Plan

By John Norris

RENSSELAER, N.Y. — NYISO last week said it will file *comments* for New York state to consider as it plans its cap-and-invest program, addressing issues such as allowances and leakage.

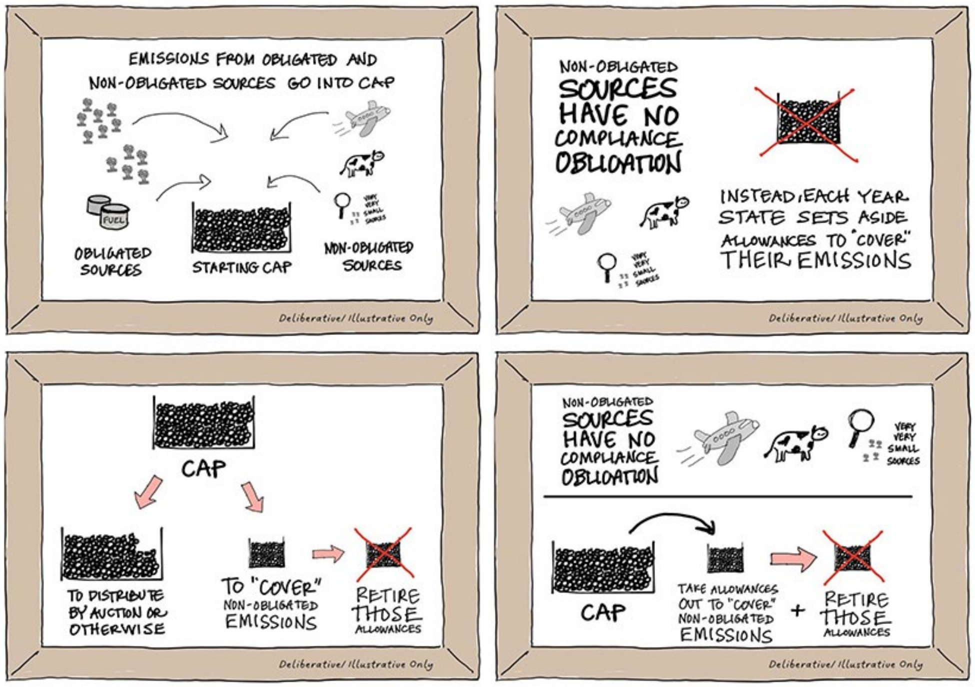
Mike DeSocio, director of market design at NYISO, told stakeholders at a meeting of the Installed Capacity Working Group and Market Issues Working Group that the ISO "supports placing a price on carbon emissions and thinks that it is very compatible with the competitive wholesale markets New York has benefited from over the last two decades."

But, he added, "we are very concerned about reliability and want to reinforce that any program should envision times where there may be a need to run generation to support keeping the lights on that have run out of allowances."

The cap-and-invest program would auction emission allowances to obligated sources, such as large-scale greenhouse gas producers, and nonobligated entities, such as agricultural or forestry industries. Nonobligated sources would see their allowances retired by the state, while obligated sources would need to purchase allowances to continue emitting. Money obtained from these auctions would go into a climate action fund, with much of it set aside for disadvantaged communities (DACs). (See *NY Climate Justice Panel Sets Disadvantaged Community Criteria*.)

"The program should be designed in a way where a generator does not need to make a decision or choice between running to keep the lights on or complying with an allowance," DeSocio said.

The ISO will also comment on how to best address leakage, as well as inform agencies that however they plan to tackle the issue, NYISO will need plenty of time to develop software compliant with the new regulations.



Overview of New York's cap-and-invest allowance proposal for obligated and non-obligated sources | *NYSERDA*

NYISO will also share its support for the creation of an independent monitor, who is able to oversee the state's policy.

"We're treating this as an opening for us to offer our experience and help New York shape the cap-and-invest program," DeSocio said. The ISO will happily provide guidance on any topic, but it would be helpful for agencies to give more insight into the program's time frame, he said.

Chris Wentlent, chair of the New York State Reliability Council's Executive Committee, asked whether NYISO plans to comment on having separate trade requirements for different DACs, and on the intent to initially have no offsets for generators.

DeSocio responded that NYISO did not plan to comment on either topic, but "both are important pieces for the state to consider, especially considering other requirements established by the [Climate Leadership and Community Protection Act], but this is not something the ISO will weigh itself into."

The state's Department of Environmental Conservation and the New York State Energy Research and Development Authority recently ended a series of *webinars* dedicated to explaining the cap-and-invest *policy* and *identifying* where public input could be most helpful to regulatory decision-making. (See *NY Starts Public Review of Cap-and-invest Plans*.)

The DEC and NYSERDA plan to have two rounds of pre-proposal outreach and ask that initial comments be submitted no later than July 1. Comments can be sent either *online* or *mailed* to the DEC's Division of Air Resources. ■

Northeast news from our other channels

BOEM Commences Environmental Review of Beacon Wind — NetZero Insider

Battery Storage Developers Bump Against Perception of Risk — NetZero Insider

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NYISO News

FERC Accepts NYISO's Revisions to CRIS

FERC on Friday accepted NYISO's proposed tariff revisions that it said will prevent generators not using their capacity resource interconnection service (CRIS) rights from retaining them and allow for more efficient transferring (*ER23-1824*).

The revisions are intended to make it easier for deactivated facilities to adjust their unexpired CRIS rights while also increasing capacity deliverability headroom and potentially lowering the cost of market entry for future facilities by lessening the need for deliverability upgrades.

CRIS is required to participate in NYISO's capacity market and can only be obtained either through a transfer from a facility with existing rights or from ISO deliverability studies.

"NYISO's proposal adds greater clarity and flexibility regarding the rules applicable to CRIS transfers and bolsters the existing CRIS retention and termination rules," FERC said. "We agree with NYISO that these revisions will help facilitate the full and efficient utilization of existing interconnection capacity by mitigating the retention of CRIS by suppliers who are not fully utilizing or who are unable to fully utilize their CRIS, and by enabling the more efficient transfer of CRIS between facilities."

NYISO had been working on the revisions since 2020. (See "CRIS Revisions Approved," *NYISO Management Committee Briefs: Jan. 25, 2023*.)

The Long Island Power Authority and energy storage development company Elevate Renewables F7 did not oppose NYISO's proposal, but they suggested several changes to address concerns they had with it. As they did not lodge any protests against the filing, FERC did not address their concerns, ruling their suggestions outside the scope of the proceeding.

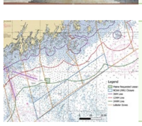
The changes went into effect Monday. ■

— John Norris

NYISO control room in Rensselaer, N.Y. | *NYISO*

Northeast news from our other channels

Checking in on Clean Energy at the Mass. Legislature NetZero Insider



Maine Gov. Vetoes OSW Bill Over Labor Requirements NetZero Insider

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NYISO News

NYISO Stakeholders Still Questioning Interconnection Queue Proposal

By John Norris

ALBANY, N.Y. — NYISO on Thursday sought once again to *clarify* its Class Year queue window concept and assuage stakeholder concerns *expressed* in previous meetings about the proposed changes to the interconnection study process.

Thinh Nguyen, NYISO senior manager of interconnection projects, told members of the Transmission Planning Advisory Subcommittee that "we want to make sure that we're reducing [interconnection] timelines and that this is an ongoing discussion amongst stakeholders."

Stakeholders, however, remained skeptical and had many unresolved questions.

"We've been pointing out each time we have these meetings that we need a focused presentation on how much of our extra work translates into extra benefit," said Mark Reeder, representing the Alliance for Clean Energy New York, referring to how the new construct would have developers complete many pre-application requirements before being able to join, which has caused confusion.

This comment was representative of the struggle stakeholders have expressed previously to NYISO, as the ISO has reworked the proposal throughout the year. (See *NYISO's Latest Queue Overhaul Draft Confuses Stakeholders*.)

Stakeholders still wanted more clarity about many parts of the concept, including project prioritization and potential off-ramps for large generators.

Doreen Saia, an attorney with Greenberg Traurig, asked about project prioritization, and whether Group A projects that finish their cluster feasibility studies could be impacted by the feasibility results of Group B projects.

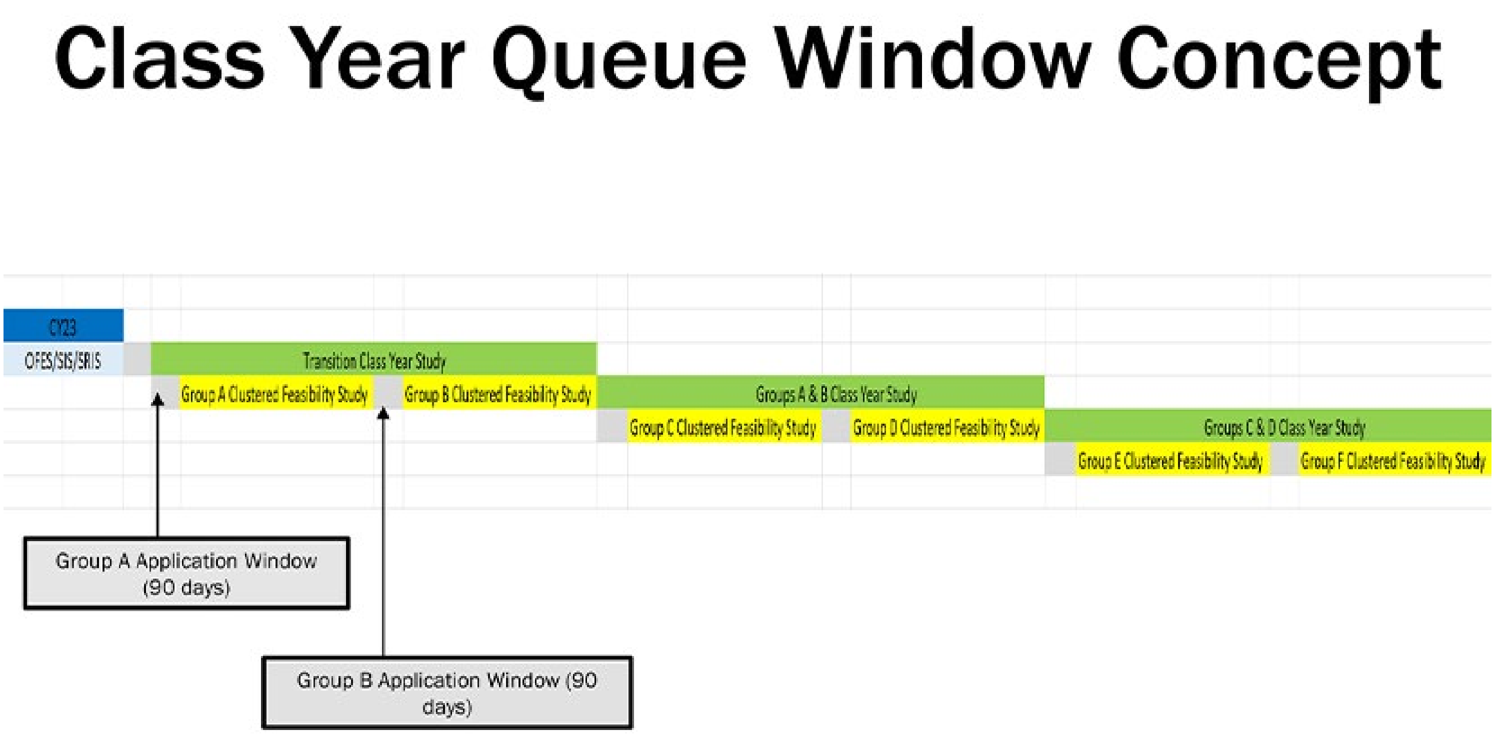
"Group A projects have priority against Group B. So, when you add Group B into the Class Year study, if there's a problem, then Group A has a much higher priority," Nguyen responded.

"I am worried that you could inadvertently undervalue the whole [concept]," Saia followed up. "If Group A projects do great, but then Group B projects come out and it is an unholy mess, [developers] may now decide they aren't willing to agree to new costs 90 days after their initial costs for Group A projects were determined."

Reeder asked whether NYISO has begun considering allowing off-ramps for large-scale projects that want to withdraw from the queue after discovering they might be infeasible. NYISO currently only allows small generators to withdraw from the queue without penalty.

Nguyen responded, "This is still on the table, but we're still going to have to think about that." Nguyen added that NYISO is aware that there are many circumstances in which a large-scale generator may need to withdraw for valid reasons.

NYISO will refine the proposal until the fall, when it will begin vetting tariff language with TPAS. It asked that comments or questions be sent by July 21, so they can be incorporated into the next meeting presentation Aug. 1. ■



Breakdown of NYISO's class year queue window concept | *NYISO*

ACORE Report Highlights Billions of Dollars in PJM's Generator Queue

Report Co-author: Enough Renewables in Queue to Wholly Replace RTO's Generation

By James Downing

Billions of dollars and thousands of jobs are tied up in PJM's generator interconnection queue, which could be unlocked if the RTO efficiently reformed it, the American Council on Renewable Energy said in a report released June 28.

The report, "*Power Up PJM*," found that moving forward with just tthe changes already approved by FERC could lead to $33 billion in investment and 199,000 job-years, defined by ACORE as the full-time equivalent of one job for one year. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

If PJM had proactively developed sufficient transmission capacity as well as enacting the revisions, it could have enabled another 100,000 job-years and $17 billion in additional capital investments in the next four years, according to the report.

PJM is just starting to implement the changes, which will move its queue from a first-come, first-served serial process to a first-ready, first-served cluster study approach, said Noah Strand, ACORE policy associate and a co-author of the report.

"Under this first-come, first-served approach, each project withdrawal would prompt a restudy of the preceding applications without the departing project in the model," Strand said on a web conference with reporters.

That worked when the queue was mainly hooking up new natural gas plants located relatively close to load, but now it needs to connect many more renewable projects that are often farther away from load — meaning they face higher interconnection costs, as transmission planning does not account for future generation.

"Data has shown that renewables pay disproportionately high upgrade costs relative to conventional fuels such as natural gas," Strand said. "And those costs have multiplied in recent years, sometimes enough to exceed the costs of building the projects themselves."

Often developers do not find out how much they will have to pay for upgrades until late in the process, which can kill off otherwise commercially viable projects, he added.

As of March, the queue had grown to more

| ACORE

than 2,600 projects totaling 260 GW; about 85% of those were renewables — enough to replace all the generation in the RTO, Strand said.

The queue data in ACORE's report does not reflect offshore wind because of the use of FERC Order 1000's State Agreement Approach, which has been used by New Jersey and is likely to be picked up by Maryland, Strand said. (See *NJ BPU Backs Plan for 2nd Grid Upgrade Process with PJM*.)

Based on how much is in the queue and the historic completion rates of planned projects, a reasonable estimate is that PJM will add about 34 GW of new renewables as it implements the approved changes in the next few years, Strand said.

"We don't expect that 100% of the renewable projects in PJM's queue will be completed, but our report holds that the development of new transmission is key to increasing the number that do get built, namely if PJM opts for the large-scale, high-voltage lines that are most needed," Strand said.

Getting that long-range transmission built would require additional changes to PJM's process, which are the subject of a pending Notice of Proposed Rulemaking at FERC. (See *FERC Issues First Proposal out of Transmission Proceeding*.)

But getting the needed transmission buildout will require more than FERC action, with the American Clean Power Association's Brendan Casey saying congressional action is required.

"I think permitting reform is essential, especially when we talk about long-range transmission," Casey said. "Some of these projects are taking 10 to 20 years from inception to start construction, and it's just not sustainable."

Getting transmission built out to meet some state policies in an RTO as diverse as PJM will be tricky, with 13 states that have varying levels of commitment to combating climate change. But several speakers on the webinar argued that the economic benefits highlighted in ACORE's queue report are enough to entice any state to build out transmission.

"The projects waiting in PJM's queue have economic benefits to offer all states and all communities where they're being developed, red or blue. That's one piece," the Rocky Mountain Institute's Katie Siegner said. "And the electricity cost benefits of these increasingly affordable new generation sources is another piece that should incentivize a bunch of different stakeholders across party lines and across different states to come together to figure out transmission planning."

A PJM spokesman responded that the RTO "reformed its interconnection queue process with stakeholder approval in record time" and will implement the new rules on July 10.

While the RTO has a large queue, it also noted 44,000 MW of resources, which are mostly renewables, have already cleared the study process, but have yet to be built. Those projects are running into delays elsewhere such as the supply chain, financing, siting or other regulatory issues. "The queue is really not the current issue," PJM said. ■

PJM News

Former Ohio House Speaker Householder Sentenced to 20 Years in Prison

Once-powerful Politician Involved in FirstEnergy Bribery Scheme

By John Funk

A federal judge in Cincinnati sentenced former Ohio House Speaker Larry Householder (R) to 20 years in prison Thursday for taking bribes from FirstEnergy to pass legislation subsidizing the company's nuclear plants.

U.S. District Judge Timothy Black ordered Householder handcuffed before deputies took him from the courtroom despite a request by his attorney to allow him to report to prison later.

Householder asked the judge for clemency on behalf of his family before he was sentenced. He is expected to appeal. Federal prosecutors asked for the maximum sentence of 16 to 20 years. Co-conspirator Matt Borges, a former Ohio Republican Party chairman, was sentenced by Black to five years Friday for his part in the scheme.

"Larry Householder led a criminal enterprise responsible for one of the largest public corruption conspiracies in Ohio history," U.S. Attorney Kenneth L. Parker said in a *statement* following the hearing. "Elected officials owe a duty to provide honest services to their constituents — transparency, integrity and accountability are foundational principles of democracy. Householder once held one of the three most powerful offices in the state of Ohio. Now, because of his corruption, he will serve a substantial prison sentence."

"The people of Ohio are the true victims of Larry Householder's corrupt scheme to increase his power and pass a billion-dollar corporate bailout," FBI Cincinnati Special Agent in Charge Will Rivers said. "While we hope this sentence clearly demonstrates that corruption does not pay, the FBI will continue to investigate and pursue those who abuse their positions and take advantage of the public."

A jury in March found Householder and Borges guilty of racketeering conspiracy charges connected to a yearslong conspiracy orchestrated with FirstEnergy. (See *Householder Convicted in FirstEnergy Bribery Case*.) Both men have been free on bond.

The arrangement enabled the speaker to funnel cash through two dark money groups to fund the election campaigns of allies in both chambers of the legislature who favored a public bailout of the company's uncompetitive Ohio nuclear power plants.

Former Speaker of the Ohio House of Representatives Larry Householder | *Ohio General Assembly*

Lawmakers approved the legislation, House Bill 6, in July 2019. Householder and the company, again using dark money connections, defeated a ballot issue nullifying the legislation. A federal grand jury indicted Householder and four others in July 2020. The legislature later removed the nuclear subsidy from the law but kept an unrelated subsidy for two 70-year-old coal power plants on the Ohio River.

Despite moving the ownership of the nuclear plants to a subsidiary several years earlier, FirstEnergy had sought ratepayer funding for them as early as 2014 in a case before the Public Utilities Commission until FERC intervened. The company's lobbying efforts for legislation creating a public subsidy died in legislative committees.

FirstEnergy, identified as "Company A" in the 2020 indictment, denied wrongdoing but then agreed to pay a $230 million fine in a deferred prosecution agreement. (See *DOJ Orders $230 Million Fine for FirstEnergy*.) Former CEO Charles Jones and Michael Dowling, senior vice president of external affairs, were fired in October 2020.

The federal probe also prompted the company to reorganize its board of directors, creating a watchdog committee to investigate top management's ethical practices. Several other senior managers have since been fired.

"Millions of Ohio utility consumers are seeing a measure of justice today, regarding the tainted House Bill 6, with the federal judge's sentencing of the former speaker of the House," Ohio Consumers' Counsel Bruce Weston said in a statement. "But more justice needs to be served. More justice should include the legislature repealing the coal power plant subsidies that the scandalous legislation still requires Ohioans to pay to AEP, Duke and AES.

"More justice also should include the [Public Utilities Commission of Ohio] lifting its stay on our and others' investigations into any improper charges to consumers by FirstEnergy." ■

PJM News

MACRUC Panels Discuss Myriad Challenges Facing PJM

Resource Adequacy Top of Mind Among Panelists

By Devin Leith-Yessian

FARMINGTON, Pa. — The Mid-Atlantic Conference of Regulatory Utilities Commissioners' (MACRUC) 28th Annual Education Conference last week at the Nemacolin Woodlands Resort focused on interregional transmission planning, resource adequacy and the risks posed by extreme weather.

Panelists on June 27 discussed the resource adequacy concerns PJM outlined in its "Energy Transition in PJM" *white paper* released in February. (See *PJM Board Initiates Fast-track Process to Address Reliability*.)

PJM Vice President of State Policy Asim Haque said the analysis found concerns around the balance between generator deactivations and new entries. As it considers how to address those challenges, he said PJM must balance the interests of member states and regions with diverse priorities.

"I do think that this is overarchingly an engineering problem that we all need to try to collectively solve together," he said.

Glen Thomas, president of the PJM Power Providers (P3) Group, said that when the Reliability Pricing Model (RPM) was adopted, there was an expectation that the value of capacity would clear at the cost of new entry (CONE), which is currently about $300/MWh. Recent auctions, however, have been clearing much lower, which he said sends a signal for generation to retire.

That has resulted in few new resources being built and generators deactivating, including the 2.2-GW Homer City coal generator in Pennsylvania shuttering this month, Thomas said. He argued that the dynamic has contributed to a decline in reserve margins over the past several years, from above 20% to falling into the single digits.

"You should not be sending a retirement signal knowing what we know now," he said.

Thomas said improving the outlook for reliability will require revising how PJM accredits resources to ensure the amount of capacity they are able to offer is accurate to their reliability contribution and reworking the market seller offer cap (MSOC) to allow generators to represent their full risk as a capacity resource.

Haque said there has been agreement that the current clearing price is not sending appropriate price signals. PJM's Board of Managers initiated the Critical Issue Fast Path (CIFP) process to solicit stakeholder proposals to overhaul the capacity market, with the goal of submitting a proposal to FERC in October. (See *PJM Continues CIFP Discussion of Seasonal Capacity Market Proposal*.)

"The goal should not be to increase prices; that should not be the goal of any market construct. The goal as we see it should be to continue to provide resource adequacy" while keeping costs effective for consumers, Haque said.

Ohio Public Utilities Commissioner Dan Conway said decarbonization is an important focus of his job, but maintaining reliability is his "first and last." As thermal resources, especially coal-fired, have retired, he said the new resources coming online lack the same reliability attributes and present a looming risk of more regular curtailments and shortfalls.

He believes that the competitive model formed by PJM offers the best path forward, saying that neighboring MISO is largely vertically integrated and is closer to the edge than PJM.

Vistra CEO Jim Burke said the thinking around renewable resources has shifted from a technology supplementing existing thermal resources to displacing them. As that transition continues, he said far more nameplate generation will need to be developed to replace the same amount of capacity, owing to renewables' lower accreditation.

Vistra CEO Jim Burke (second from left) speaks during a June 27 panel at the Mid-Atlantic Conference of Regulatory Utilities Commissioners (MACRUC) Annual Education Conference. He was joined by (from left) PJM Vice President of State Policy Asim Haque, P3 President Glen Thomas and PUCO Commissioner Dan Conway. | *© RTO Insider LLC*

"The scale of this is one of the biggest things that I'd just like to emphasize. We're nowhere near a one-to-one trade," he said.

While much of the discussion in PJM has been on the pace of new development, Burke said ERCOT has seen a large amount of investment over the past 20 years but continues to have reliability concerns during peak loads, noting that Texas was experiencing a heat wave straining the grid as the conference was ongoing.

"We're $100 billion in, and we're still checking the app everyday," he said, referring to ERCOT's mobile dashboard.

Interregional Transmission Spotlighted

During a June 26 panel on interregional transmission planning, discussion centered on how new transmission buildout — especially between RTOs — could address growing risks from extreme weather.

The Brattle Group's Joe DeLosa III said the company's analysis has found that additional transmission could have provided about $1 billion in value during the December 2022 winter storm — also known as Winter Storm Elliott — paying itself in just the four days of the storm. Despite the benefits, he said new lines largely aren't being built in part because the multi-driver approach doesn't capture

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independent transmission needs, and the sequencing of how needs are considered creates a patchwork of regional projects.

Resolving cost allocation disputes poses a challenge to transmission development, but DeLosa pointed to MISO's planning process as a success in realizing benefits that are greater than the costs. For it to work in the Mid-Atlantic, he said close collaboration will be needed between states, RTOs and FERC.

Jeff Dennis, deputy director for transmission at the U.S. Department of Energy's Grid Deployment Office (GDO), said his staff are focused on exploring improvements that can be made beyond the RTO-level, such as siting, permitting and other processes that can be streamlined to get transmission built without compromising on environmental justice communities.

In a study the GDO plans to release this fall, investment trends and wholesale price differentials were used to identify constraints, with preliminary results suggesting that new transmission would provide significant value when storms are stressing the grid.

Looking at scenarios with high clean energy penetration and high load growth, the study's preliminary results find that there is significant need for interregional capacity transfer capability, particularly between the Midwest and Mid-Atlantic. As much as double the current transfer capability could be needed, as well as additional interchange between the Mid-Atlantic and Southeast.

Barbara Tyran, of the American Council on Renewable Energy, said much of the U.S.' solar and wind potential lies between the Mississippi River and the Rocky Mountains, but only a fraction of it could currently be connected with load centers on the coasts with existing transmission.

FERC's Jessica Cockrell said cost allocation has to balance planning and the needs of merchant generation to avoid eroding the value of projects. When considering how capacity transfer can be mandated between regions, she said that operational agreements can be reached to determine the share of capability on each line that can be used to flow power from one RTO to another.

David Townley, director of public policy for CTC Global, said grid-enhancing technologies such as reconductoring, dynamic line ratings, fast power flow controllers and energy storage can be used to get more out of existing infrastructure without needing to get new developments through the siting and permitting processes. One of the challenges with installing those technologies is a lack of understanding among utilities in how they can be used, he said.

Utility Executives Discuss Extreme Weather Impacts

Executives from some of the largest utilities in the Mid-Atlantic discussed how extreme weather could impact their operations, as well as how differing policies across the states in which they operate interact together and with federal law.

Dominion CEO Robert Blue said the company was able to maintain service throughout its PJM footprint during Elliott, but it implemented load shedding in other regions. That experience has led it to consider adding LNG storage to some of its large gas-fired generators to address some of the fuel security issues seen during the storm.

Exelon CEO Calvin Butler Jr. said the number of severe weather events has tripled in its region, especially microbursts that come in with minimal warning and put tens of thousands of customers without power. He said improvements in communications have reduced response times, and drones are now being used to detect obstacles that could prevent crews from using a route to access a repair site, aiding in sending the right equipment to where it's needed.

"What we are finding is the storm forecasts are less and less predictable," he said.

John Crockett III, president of LG&E and KU Energy, said wind storms are also posing an increasing challenge. High winds during Elliott contributed to three hours of load shedding, along with issues with an interstate pipeline causing some gas generation to be unavailable. A storm in early March brought wind speeds exceeding 60 mph and left around 400,000 customers without power.

Butler said Exelon's decision to shift to multiyear planning in some states has allowed greater transparency and collaboration, with more detail than annual rate cases. The intervenor process is also changed with multiyear plans, allowing discussion of how rates interact with the policy goals of a state or intervenor.

While the federal government has made billions available to promote its climate and reliability goals, Butler said its actions haven't always matched its ambitions. Both there and at the state level, legislation is interacting with decades-old regulatory frameworks, which he said can sometimes impede policy goals.

Lightning Round Discussions on Key Issues

During a series of lightning round discussions, several speakers shared their thoughts on the potential of green hydrogen, congressional bills addressing permitting authority, how investors view the state of the energy markets, and an upcoming report on coordination between the gas and energy industries being written by the North American Energy Standards Board (NAESB).

Bank of America's Julien Dumoulin-Smith said investors are expecting costs for wholesale energy, interconnection and new generation — particularly offshore wind — to generally rise in the PJM region over the coming years.

He predicted that there will continue to be ample capital available for new developments, but the cost of capital is likely to rise with interest rates. Offshore wind installation costs, for example, could double because of interest rates, while concerns linger about whether the ships and logistics required to put the turbines in place are sufficient for looming projects.

"There's clearly capital available in both debt and equity capital markets, and I think you're going to see a lot of traditional equity getting raised in lieu of debt in this environment," he said.

With rising interconnection costs and a growing gap in the valuation between clean and thermal assets, he said some resources are now worth just the value of their interconnection, reducing their prospects for continued operations.

"In this day and age, I don't think you're going to see a lot of tolerance if there are operational issues. If you see other issues on gas plants today, you're going to see people favoring to take them out," he said.

Constellation Discusses Hydrogen Development

Constellation Energy Executive Vice President Kathleen Barron said hydrogen offers a potential solution to several areas of the economy that have proved challenging to decarbonize but remains uneconomical for the time being.

"We have proven technology; we know how to do this; companies are actually already doing this at one of our sites in New York, using nuclear energy to make hydrogen using electrolysis," she said. (See related story, *Constellation Gives Details on First-in-nation Pink Hydrogen Production*.) "The problem is the cost of doing that is about three to four times what a customer is

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going to be willing to pay to use hydrogen as a substitute for natural gas."

Barron said the Infrastructure Investment and Jobs Act provides funding for hydrogen hubs to jumpstart the production and transportation infrastructure necessary for mass industrial use of hydrogen, but the "additionality" clause in the law could pose a roadblock. The clause requires that only new clean energy can be used to power the electrolyzers, but she said it would require a doubling of the amount of renewable power currently available and to only use that energy to produce hydrogen.

"We'd need to double the size of today's renewable grid and use it only to make hydrogen — not use it satisfy state [renewable portfolio standard] programs or to satisfy the EPA rules that are coming. ... If we really want to try to tackle emissions in other sectors, and we want to use hydrogen, we're going to need to use" existing generation, she said.

Nuclear makes hydrogen cost effective because of its steady supply of power and the existing transportation infrastructure that tends to be in place at those facilities," Barron said. Nuclear plants also tend to be further from population centers and have land available around them, raising the possibility of placing electrolyzers behind generators' interconnection meters, a configuration the company has been proposing through the PJM stakeholder process. (See "Discussion Continues on Capacity Offers for Generators with Co-located Load," *PJM MIC Briefs: June 7, 2023*.)

NextEra Evaluating Hydrogen Uses

NextEra Energy Resources Vice President of Development Ross Groffman also spoke about how green hydrogen could be used for industrial decarbonization. Some of the initial uses the company is developing projects for are green ammonia production to create agricultural fertilizer and liquid hydrogen as fuel for long-haul trucks and buses.

Hydrogen could also be used in steel and chemical production or blended into the fuel for natural gas generators, he said.

Intermittent resources sited alongside hydrogen could also be used for energy production when generation exceeds the amount of power the electrolyzers consume. Using hydrogen to fuel combustion turbines will play a central role in the future of decarbonizing the grid, Groffman predicted, and the NextEra is already investing in projects to explore technologies.

"It's an important part of the long-term view of how some of these plants will run. It's not going to happen in the next year or two; this is longer term, but it will be a key part of how the long-term green grid will perform," he said.

Congress Considering Siting and Permitting Legislation

Christina Hayes, executive director of Americans for a Clean Energy Grid, shared her views on a slate of bills being considered by Congress that would address how the federal government interacts with siting and permitting of energy infrastructure. Some of the proposed legislation would offer transmission tax credits "as a kind of hook to getting siting and permitting handled more broadly."

Hayes said there's also a growing recognition of the need to incorporate community benefits and other impacts on where projects would be developed, both for pipelines and transmission.

With renewable standards now widespread not only among states, but also utilities and corporations, she said many are coming around to the need for more transmission to be built.

When considering the impact to their ratepayers, she said regulators could be more thoughtful when considering approval of transmission projects that would benefit other states, saying those could be viewed as an "insurance policy" for their future reliability.

NAESB Drafting Recommendations on Gas-Electric Coordination

Robert Gee, co-chair of NAESB's Gas-Electric Harmonization Forum, gave an update on the recommendations being drafted with the aim of improving the coordination between the two industries. He encouraged all interested parties to either submit written comments or participate in the meetings, of which there have already been a dozen.

There are both operational and structural issues that impact the ability for gas generators to procure fuel during emergency conditions, Gee said, leading NAESB to consider creating a commercial standard or emergency protocols.

"Generators are not able to access gas during critical peak periods for a number of reasons. One is that they don't have firm contracts, generally for economic reasons. Second, there's inadequate information regarding available pipeline capacity and little to no transparency on certain parts of the system," he said.

Gee reviewed a handful of the 17 recommendations that the forum is currently considering, include increasing the transparency and communication around the status of interstate pipelines, ensuring that gas markets are fully functioning around the clock to allow generators to prepare for peak demand during emergency periods, and synchronizing the gas and electric markets to align the electric industry's day-ahead procurement schedule with how generators procure fuel.

The forum is also considering recommending re-evaluation of whether out-of-market solutions are needed.

"We rely on competitive markets to basically give us the ability and tools to address this issue of trying to access gas during critical peak periods. We think it's time to reconsider out-of-market solutions; weigh them carefully; see whether they work; see what they offer solutions to," he said.

Gee said that thought is also being given to recommending that two studies be commissioned by FERC and NERC to look at whether markets currently offer proper incentives for generators to procure firm fuel contracts during emergency conditions and to develop more gas storage infrastructure. ■

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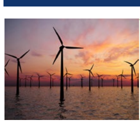

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PJM News

Former FERC Commissioners Share Outlooks with MACRUC

Commissioners Discuss Emergencies, Delaying Retirements, Coal

By Devin Leith-Yessian

From left: Suedeen Kelly, Jason Stanek, Philip Moeller, Richard Glick and Robert Powelson sit on a panel discussing the relationship between state and federal regulators on June 28. Stanek, who served as chair of the Maryland Public Service Commission, moderated while the panelists were each former FERC commissioners. | *© RTO Insider LLC*

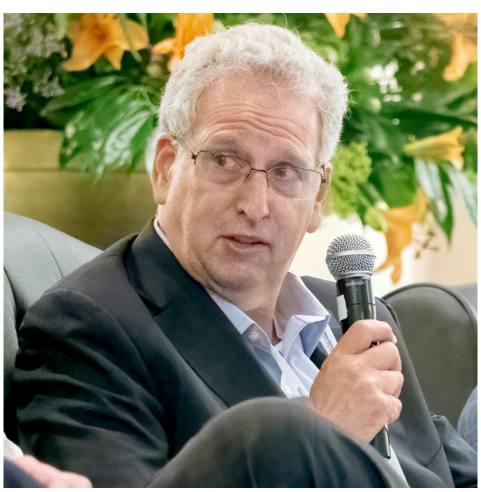
FARMINGTON, Pa. — Several sitting and former FERC commissioners shared their views on the future of RTOs and the relationship between state and federal regulators during the Mid-Atlantic Conference of Regulatory Utilities Commissioners (MACRUC) annual educational conference last week.

Speaking during the opening sessions of the conference June 26, acting FERC Chair Willie Phillips said cyber and physical security, the changing resource mix, extreme weather risk and the challenge of building the transmission necessary for the clean energy transition are some of the most critical issues the states and commission are likely to face in coming years.

Former Commissioners Suedeen Kelly, Philip Moeller, Robert Powelson and Richard Glick, the last of whom served as chair until January, sat on a June 28 panel discussing how communication between state and federal regulators can be improved. That forum was moderated by Maryland Public Service Commission Chair Jason Stanek, a former FERC senior staffer.

Both panels were asked how FERC should respond if it concludes that state policies are jeopardizing reliability by causing resources to retire without adequate replacement capacity. Glen Thomas, president of the PJM Power Providers group, asked the panel if the commission would take action in such a scenario.

"In this situation where you have a state policy that is causing pretty significant impacts in other states, is there a role for FERC here? Is this a situation where FERC just shrugs its shoulders and says, 'Well it's a state; it gets to do what it wants to'? Or is this a situation where FERC recognizes the interstate impacts of a state's action and can do some things to balance the equity?" he asked.



Former FERC Chairman Richard Glick | *© RTO Insider LLC*

Kelly said the grid requires resources that are dispatchable, a characteristic that renewables largely lack. Until enough utility-scale storage can be developed, she said, thermal resources will have to be retained to maintain reliability.

"If you aren't at the point where we can dispatch all of our renewables, we need our tried-and-true dispatchable generators, including gas-fired. As much as the community may not want carbon emissions, I think it's important to educate the community that you can't have 100% green without storage and in the meantime, we need other ways to ensure our renewables are dispatchable," she said.

Glick said FERC's ability to delay retirements is limited and the industry may need to find out-of-market solutions to ensure enough capacity remains available.

"You do have to have market reform, but I also think you have to engage — and I think you're seeing it more increasingly frequently — you have to have out-of-market solutions to keep plants around, to take other actions to keep the lights on while the [development of] transmission's underway, [and] while battery storage technology comes into play," he said.

Powelson said shutting down units could have a cascading effect that impacts other states and requires increased use of reliability-must-run (RMR) contracts.

"We're all in this together, and my concern is we move too fast and we start having these out-of-market RMR contracts, and that's not good for consumers; that's not good for the long-term future of grid reliability," he said.

When asked about the future of coal plants, Phillips said they will likely continue to play a role for at least the next five years. Gas-fired resources will likely continue operating years past that, while coal units will see economic pressure to deactivate.

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Speaking on June 26, Phillips said streamlining the path for building new transmission could provide the "biggest bang for the buck" in getting new generation on the grid. Much of the nation's infrastructure is over 50 years old and will soon need replacement. He said it may be necessary for RTOs and regulators to begin using a 20-year planning horizon and to explore regional planning. The commission may also explore interregional transfers, he said, pointing to the benefits the capability provided during the February 2021 winter storm.

Also, many projects are designed with a single purpose and don't consider additional benefits that could be realized.

"We do have projects that sit in silos. They're siloed because of reliability, they're siloed because of economics or jobs; what I would like to see are more multi value projects," he said.

Fixing Cost Allocation

One of the challenges Phillips anticipates is how to address cost allocation, which he said the commission will likely be addressing in the near future.

On June 28, Glick said interstate transmission projects can be difficult to plan when the cost allocations and benefits for each state do not match. While Congress is discussing providing FERC with preemptive siting authority on some lines, he said buy-in from the states will lead to a better outcome.

"The current approach to siting — obviously it can be problematic because there are some cases where some states may not have as much of an incentive to site a line if they feel it's going to benefit another state, but they're going to have to pay a significant share of the cost. So fixing the cost allocation problem is a big part of it," he said.

Kelly said the commission has seen growing opposition to projects, including a convergence across the political spectrum as conservative landowners and liberal environmentalists turn to FERC to push against developments. She said developers of projects such as the West of Devers line in California or Western Spirit in New Mexico were able to build transmission to clean energy by engaging in dialogue with local communities.

"Both of those have been characterized by intense working with the community to try and understand what the communities' opposition or problem with it is and accommodate it," Kelly said. "Oftentimes that accommodation comes not just in changing the siting, which is oftentimes what we did at FERC when we

FERC Chair Willie Phillips speaks during the opening sessions of the Mid-Atlantic Conference of Regulatory Utilities Commissioners (MACRUC) on June 26. | *© RTO Insider LLC*

were talking about natural gas pipelines, but in spending the money necessary to take care of some of the concerns in communities that were going to be impacted."

"One thing that we should think about as regulators — state and federal regulators — is can we be a force to further the discussions of transmission developers with the communities and maybe be part of that and facilitate that," she said.

Following the commission's roundtable on environmental justice last month, Phillips and Glick both spoke about the importance of listening to communities' concerns and ensuring that the benefits of the clean energy transition are felt by all.

Phillips said it's a personal priority of his, being from Alabama where he grew up in the shadow of heavy industry. He said FERC has streamlined the permitting process to create a legal obligation for communities to be given a voice. Not enough of the public is participating in hearings, he said, but the commission's Office of External Affairs is working on improving its consultation process.

Glick recounted visits he made to Port Arthur, Texas, and Lake Charles, La., to view the impact polluting industry has had on residents there. While those aren't FERC-regulated industries, he said it showed the potential consequences when environmental justice isn't considered.

Hearing from residents and putting conditions on FERC orders to address communities' concerns during the FERC process can also avoid legal challenges to its decisions and help get projects built easier, Glick said. ■

PJM News

NJ Backs $150 Million Hike for OSW Transmission

BPU Attributes Increase to Closer Cost Estimate Analysis

By Hugh R. Morley

The New Jersey Board of Public Utilities (BPU) on Thursday approved an additional $150 million of expenses for the state's $1.07 billion transmission project to connect offshore wind farms to the grid, saying the extra cost would not undercut the project's financial benefits for ratepayers.

The 14% increase follows by eight months the board's approval of the project in what the agency said was the first use in PJM of FERC's state agreement approach (SAA), which allows a state or group of states to initiate a project to fulfill state policy requirements as long as they foot the bill for associated costs in the RTO's transmission plan.

The cost rise comes amid growing scrutiny of New Jersey's ambitious clean energy commitments, especially the plan to develop 11 GW of offshore wind capacity, with some Republicans and business groups demanding an estimate of the cost to ratepayers and questioning whether the investment is worthwhile.

As the BPU acted, state lawmakers in a last-minute vote before the summer recess backed a bill that would enable Danish developer Ørsted to receive federal tax credits to help meet cost increases in its Ocean Wind 1 project, rather than the state receiving the benefits of the credits. (See *NJ Lawmakers Back Ørsted's Tax Credit Plea*.)

"We have to keep moving forward," BPU President Joseph L. Fiordaliso said before the board's 5-0 approval of the *order* outlining the increase. "There are unfortunately many unforeseen developments that have occurred over the past couple of years prior to the pandemic and after the pandemic as far as the economy is concerned, where we see increases that were never anticipated."

The BPU endorsed additional expenses of $40.76 million for several changes — described as "interconnection work" — in the scope of work, or additional elements of construction that were not part of the original bids approved in the solicitation. Part of that expense will pay for the engineering, procurement and construction of cables and connection points that would tie the offshore projects to the grid.

The interconnection cost increases also included Jersey Central Power & Light's replacement of 115- and 230-kV transmission lines to make way for larger lines, and the replacement of certain equipment.

| Shutterstock

The board also approved $109.5 million in "scope-related cost estimate adjustments," cost increases resulting from a closer analysis of the developer's work and estimates. That included $27.1 million for the "reconductor of a small section" of a 230-kV line as a result of "updated communication between the developer and PJM," which is a partner to the BPU in the SAA project. An additional $71.9 million stemmed from the "additional refinement" of the developer's "cost estimates for their awarded scope," which the BPU expected at the time the project was awarded, the order states.

The $109.5 million estimate was reduced from the previously released revised estimate of $127.34 million, which was first reported at a May 9 meeting of the PJM Transmission Expansion Advisory Committee. (See *NJ BPU Pulls Offshore Tx Project Mod from Agenda After Complaint*.)

Ratepayer Benefits

Andrea Hart, BPU's senior program manager for offshore wind, told the board the changes would not affect the agency's estimation that the selected SAA solutions would save ratepayers more than $900 million, a figure calculated by looking at the "cost of the transmission facilities that would be necessary to achieve New Jersey's offshore wind goals in the absence of an SAA solution."

That's because, according to The Brattle Group, a consultant working on the project, the cost increases would have been incurred anyway had the agency opted to tie in the offshore projects to the grid using a non-SAA agreement approach.

"Clearly, price increases are not uncommon," said Commissioner Zenon Christodoulou. "But as a consumer, they're never welcomed. So although we accept this and we appreciate all the efforts, I think that additional changes might not be as welcome."

Brian Lipman, director of the New Jersey Division of Rate Counsel, who first raised concerns about the hikes in June, said he was "skeptical that these increases result in no change to the amount of benefit to be seen by ratepayers."

"We still question whether the scope changes are in fact prudent increases," he said in an email to *RTO Insider*. "It is unclear to Rate Counsel why some of these issues were not identified in the initial bid. While we understand that some changes may be necessary (equipment not available or has been updated) these changes appear to be due to a failure to fully understand the project when bid.

"These increases are not due to changes in economics or increases in materials," he wrote. "These changes are coming about because as the developers take a closer look at the work they bid to do, they realize that changes need to be made."

Anticipated Future Hikes

The BPU awarded the main part of the SAA project — costing $504 million — to Mid-Atlantic Offshore Development (MAOD) and JCP&L to build a new substation called the Larrabee Tri-Collector Solution next to an existing JCP&L substation through which offshore wind projects would tie into the grid. The agency also awarded contracts totaling $575 million to seven smaller projects to upgrade existing onshore transmission identified by PJM as necessary.

The agency's awards focused only on infrastructure on land, leaving the offshore infrastructure to be completed later by offshore project developers. (See *NJ BPU OKs $1.07B OSW Transmission Expansion*.)

The order approved by the BPU last week said the original project selection anticipated that additional interconnection work would be needed but did not define whether it would be done by the SAA project developer MAOD or an offshore wind developer. Documents for the BPU's third OSW project solicitation, released in March, outlined the winning developer's responsibility for "prebuild infrastructure" that would build the necessary duct banks and access cable vaults to be used by all OSW projects to the new Larrabee substation.

The solicitation documents did not specify whether MAOD or the winner of the third solicitation would build certain parts of the infrastructure, and the BPU and its consultants recently concluded that the work would be best done by MAOD, adding to its costs, the order said. Pursuing that option would allow the work to be completed faster than waiting for the third solicitation process to be completed, would be safer and would yield various technical benefits, the order said.

The work included the engineering, procurement and construction of infrastructure to "accommodate" four high-voltage direct current and the work needed to design and build the trenches and collector lines for three alternating current lines, the order said.

"As transmission projects develop, it is common, if not expected, for cost estimate adjustments to occur," the order states. "As such, additional cost estimate adjustments, in addition to the cost estimate adjustments noted herein, may be anticipated in the future." ■

Southeast

NC Businesses Endorse Market Reform Studies

Legislation Would Require Study of RTOs, ISOs, SEEM

By Holden Mann

A group of North Carolina businesses urged the state's legislature and governor to support studying "wholesale market competition options," including an RTO, saying they were "concerned over limited access to cost-competitive, clean energy."

In a *letter* sent Thursday to the General Assembly and Gov. Roy Cooper (D), the businesses endorsed North Carolina House Bill 503, introduced in March. The bill would direct the North Carolina Collaboratory — a clearinghouse established among the state's public universities to provide useful research data to state and local governments — to "evaluate reform of the [state's] regulatory wholesale electricity market."

Studies undertaken under the bill would have to include an evaluation of designated market structures — an RTO within either North and South Carolina or the entire Southeast U.S.; an energy imbalance market within the same areas; or participation in the Southeast Energy Exchange Market (SEEM) — along with "any other market reforms the Collaboratory [deems] appropriate."

In May, the South Carolina Legislature received a report that said participating in an RTO could provide the state benefits of up to $362 million per year. (See *Brattle Report Sees Benefits for SC RTO Membership*.)

Signers of the letter include hotel chain Marriott, food and beverage brands Sierra Nevada and Nestle, solar power developer Carolina Solar Energy, and Unilever, along with advocacy groups such as the Carolina Utilities Customer Association and the Clean Energy Buyers Association (CEBA).

In a *statement* on CEBA's website, Reese Rogers, the organization's Southeastern market and policy innovation manager, said "expanding [the state's] market options … would help drive innovation and cost savings for all energy customers and improve grid reliability and resilience."

"House Bill 503 would open a path for North Carolina to move toward greater options for customer choice and grid reliability," Rogers added.

Despite the legislation's nod toward SEEM, CEBA has been an active opponent of the

The North Carolina State Capitol in Raleigh | Orchidus, *CC BY-SA 4.0*, via Wikimedia Commons

market since it was proposed. It is party to a lawsuit in the D.C. Circuit Court of Appeals seeking to overturn SEEM's approval by FERC in 2021. (See *Environmental Groups Appeal SEEM in DC Circuit*.)

Topics to be examined under the legislation include the costs, benefits and risks to a range of stakeholders from both the state's current electric system and potential market changes in terms of generation capacity adequacy and diversity, customer service and rates, environmental quality, and other factors. The Collaboratory would also be tasked with identifying any laws, regulations and policies that may need to be changed to implement reforms, their impact to disadvantaged populations and communities, and any challenges associated with nuclear plants within the state.

While the proposed studies do not specifically mention reliability, the topic is prominent in the bill's introduction, which says "North Carolina must be prepared for future weather events," such as the 2022 holiday storms that led Duke Energy to implement rotating outages that left about 500,000 customers without power. (See *North Carolina Regulators Face Questions on Holiday Outages*.)

The introduction links the topics of reliability and market reform by noting that the state's electricity is predominantly "provided by vertically integrated … distribution and transmission" utilities, and citing previous legislation requiring utilities to "diversify the resources used to reliably meet … energy needs."

The businesses' letter also referred to the winter storm blackouts, saying they "highlight the urgent need for sufficient reliable and affordable electricity in North Carolina." The businesses added that the "ability to source clean, competitively priced [reliable] electricity … is a core factor in where we decide to make or maintain investments" and warned that "limited access to cost-competitive, clean energy" might discourage companies from doing business in the state. ■

SPP News

FERC Denies Rehearing over SPP Z2 Credits

By Tom Kleckner

FERC last week rejected four separate rehearing requests related to SPP's revenue credits under Attachment Z of its tariff, reaching the same conclusion it did in a November order last year while also offering clarifications.

Oklahoma Gas & Electric (*EL19-77*), Western Farmers Electric Cooperative (*EL19-93*), Cimarron Windpower (*EL19-96*) and four renewable developers (*EL19-75*) asked for a rehearing of FERC's previous ruling. The commission's order partially granted complaints over SPP's revenue-crediting process but rejected OG&E's complaint. (See *FERC Partially Grants Z2 Protests Against SPP*.)

Citing the 2020 *Allegheny Defense Project v. FERC* decision that ruled the commission could no longer grant rehearing requests "for the limited purpose of further consideration," FERC on June 27 denied each of the requests "by operation of law."

The commission modified its discussion in the OG&E docket and set the order aside, in part. The utility had argued that requiring it to refund revenue credits related to the use of its transmission facilities would violate Attachment Z2 and a sponsored upgrade agreement with SPP dating back to 2008.

Under Attachment Z2, SPP transmission customers that fund network upgrades can be reimbursed through transmission service requests, generator interconnections or upgrades that could not have been honored "but for" the upgrades. SPP had been trying to replace Z2 credits since 2016, when controversy arose after the grid operator identified eight years of retroactive credits and obligations that had to be resettled after staff failed to apply credits. (See *SPP Invoices Lead to Confusion on Z2 Payments*.)

FERC agreed with OG&E's contention that SPP had violated Attachment Z2 during the historical period and that the commission erred in finding the utility had not raised this argument. It also found that, consistent with its findings in the other three proceedings, SPP violated the attachments, sponsored upgrade agreement and the filed rate doctrine.

The commission said even if SPP acted in good faith in implementing and administering Attachment Z2, the tariff violation may result in an outcome that is unjust and unreasonable and/or unduly discriminatory or preferential. It granted OG&E's complaint in part "insofar as OG&E alleged" the violations.

However, FERC again denied OG&E's requested remedy — that SPP refund Z2 revenue credits. It said the grid operator lacked revenue credits to provide as restitution and that those funds lie instead with the transmission customers that SPP's tariff "excuses from credit payment obligations."

BHE Renewables, Marshall Wind Energy and Grand Prairie Wind filed a limited request for clarification or a rehearing. The commission responded by explaining that it granted several parties' late motions to intervene in the dockets, although it did not list them. It said it granted their interventions "given their interest ... as demonstrated in their motions to intervene and the absence of undue prejudice or delay."

"Because we grant intervenors' request for clarification, we dismiss as moot their alternative request for rehearing," FERC said. ■

OG&E's participation in the Oklahoma Wind Energy Center led to transmission upgrades and Z2 credits. | *Oklahoma Municipal Power Authority*

SPP News

FERC Approves Revisions to SPP GI Process

By Tom Kleckner

FERC on June 27 accepted SPP tariff revisions that clarify its interconnection (IC) customers' financial security refunds, effective April 1, 2023, and subject to a compliance filing within 30 days of the order (*ER23-841*).

The commission found SPP demonstrated that the revisions are just and reasonable and not unduly discriminatory or preferential and would comply with FERC's rulemakings concerning the *pro forma* generator interconnection procedures (GIPs) and agreements.

Under the revisions, SPP will determine whether an interconnection customer withdrawing its request after the first two decision points of the RTO's three-phase GI study process is subject to forfeiting its financial security. SPP will evaluate the withdrawal's effect on upgrade costs for "equally- or lower-queued" IC requests within the "actively studied clusters."

FERC said the revisions "therefore clarify which interconnection requests are evaluated in SPP's impact analysis." It said the revisions improve certainty for IC customers, meeting the purposes of its *pro forma* GI procedures and agreements rulemaking.

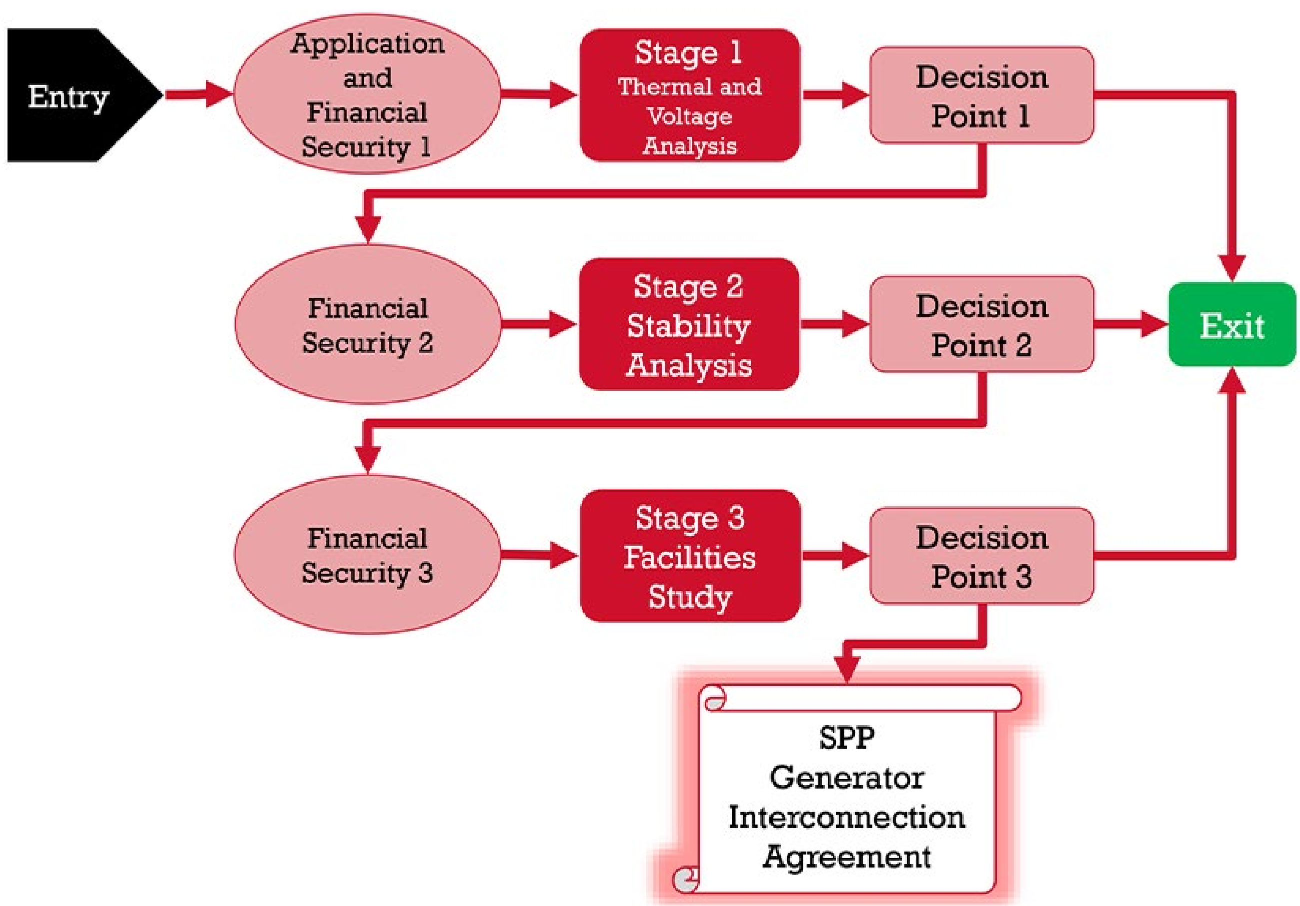
In addition, SPP proposes revisions to GIP section 8.14(e) to apply the financial security forfeiture exemptions in GIP section 8.14(d) to interconnection requests that are subject to any restudies after Decision Point 2 that are performed in accordance with GIP sections 8.8 and 8.13.

The proposed revisions to GIP section 8.14(e) also provide that if an interconnection request is restudied and it meets the forfeiture exceptions under GIP section 8.14(d), the IC customers will have 15 business days after the restudy results are posted to decide whether to withdraw requests. The commission said the 15-day deadline "should help streamline the study process" by encouraging IC customers to make timely decisions about whether they intend to proceed to the next study stage after a restudy.

"We find that the proposed revisions ... strike a reasonable balance between giving an interconnection customer an opportunity to withdraw from the queue without forfeiture of the [security] payments if allocated upgrade costs significantly increase after a restudy and allowing SPP to administer its queue in an efficient and timely manner," FERC said.

Several renewable energy developers protested SPP's proposal when it was filed in January, saying it reduces an IC customer's ability to have its posted financial security refunded when withdrawing due to a substantial increase in allocated upgrade costs. They argued that the proposed revisions unreasonably deny IC customers the opportunity to claim a forfeiture exemption if the grid operator revises its second phase's results without a restudy.

The commission approved SPP's three-phase IC study process in 2019. (See *FERC OKs New SPP Interconnection Process*.) ■



SPP's three-phase GI study process | *SPP*

Company Briefs

Lordstown Motors Files for Bankruptcy

Electric truck manufacturer Lordstown Motors filed for bankruptcy protection last week and put itself up for sale after failing to resolve a dispute over a promised investment from Foxconn.

The automaker filed for Chapter 11 protection in a Delaware bankruptcy court. In the complaint, Lordstown accused Foxconn of fraudulent conduct and a series of broken promises in failing to abide by an agreement to invest up to $170 million in the manufacturer. Foxconn previously invested $52.7 million in Lordstown as part of the agreement and currently holds an 8.4% stake in the company.

More: *Reuters*

PG&E Seeks Federal Loan to Meet Demand

Pacific Gas and Electric Company is seeking $7 billion in federal loans from the Department of Energy to help meet its growing demand for electricity and prevent wildfires.

The loan request would help PG&E build new transmission lines, increase voltage on existing transmission lines and bury more lines underground. PG&E said it expects demand to grow about 27% between this year and 2035, according to a planning document dated last year.

PG&E CEO Patti Poppe said the loan would lower costs for both the company and ratepayers, estimating that every $1 billion in loans will save PG&E $20 million.

More: *San Francisco Chronicle*

Canadian Solar to Build Factory in Texas

Canadian Solar last week said it plans to build a manufacturing plant in Mesquite, Texas, this year that is expected to produce up to 20,000 photovoltaic panels per day.

The manufacturing facility is part of a $250 million investment by the company and is its first such facility in the U.S.

Production is expected to begin by the end of the year.

More: *KXAS*

Federal Briefs

DOT Awarding $1.7B to Buy Electric, Low-emission Buses

The Department of Transportation last week announced it is awarding almost $1.7 billion in grants for 46 states and territories to buy zero- and low-emission mass transit buses.

The grants will enable transit agencies and state and local governments to buy 1,700 U.S.-built buses, nearly half of which will have zero-carbon emissions. Funding for the grants comes from the 2021 bipartisan infrastructure bill.

The U.S. has invested a total of $3.3 billion so far. Government officials expect to award roughly $5 billion more over the next three years.

More: *The Associated Press*

Report: Global Industry GHG Emissions Still Rising

A new report by the Energy Institute found that fossil fuels continued to make up 82% of the world's total energy consumption in 2022, causing greenhouse gas emissions to climb by 0.8%.

The report found that renewable energy sources (excluding hydro) met just 7.5% of the world's demand last year and represents an increase of 1% over the previous year. Solar generation climbed by 25% in 2022, while wind power output grew by 13.5%.

Global oil demand rose by 2.9M barrels a day last year to reach an average of 97.3M b/d for 2022 At the same time, demand for coal rose 0.6% compared with 2021.

More: *The Guardian*

State Briefs

CALIFORNIA

LA DWP to Halt Water, Power Shutoffs During Extreme Weather

The Los Angeles Department of Water and Power Board of Commissioners last week voted unanimously to cease water and power shutoffs due to nonpayment during extreme weather events.

The decision will direct the department to adopt local alerts from the National Weather Service as a "trigger" for suspending utility shutoffs during extreme heat and cold weather events, effective immediately.

More: *Los Angeles Times*

SCE, Leeward Renewable Sign PPA

Leeward Renewable Energy and Southern California Edison last week announced that they have entered into a 15-year power purchase agreement for LRE's 126-MW Antelope Valley BESS facility.

Construction will begin this year, while the project is expected to be operational in early 2024.

More: *Solar Industry*

DELAWARE

Lawmakers Pass Bill to Reduce GHG Emissions

State lawmakers last week passed the Climate Solutions Act, which seeks to reduce greenhouse gas net emissions by 50% by 2030 and reach a 100% net reduction by 2050.

The legislation requires the state to write a climate action plan to meet these goals with the intent that it would be updated every five years.

The bill now heads to Gov. John Carney.

More: *Delaware News Journal*

FLORIDA

DeSantis Vetoes Fleet EV Bill

Gov. **Ron DeSantis** last week vetoed a bill that sought to smooth the way for state agencies to incorporate EVs into their fleets.

The bill would have required state agencies to buy vehicles that use ethanol and biodiesel blended fuels, as well as natural gas fuel, when possible. Those who purchase vehicles for state agencies also would have been required to consider the entire lifetime cost of the vehicle, not just the purchase price, when evaluating bids. The bill also directed the Department of Management Services to make recommendations to other departments on how to include EVs and vehicles using alternative forms of energy into their fleets by July 1, 2024.

More: *Florida Politics*

GEORGIA

Plant Vogtle's Unit 3 Delayed Again

Georgia Power last week announced that one of the two new nuclear reactors at its Plant Vogtle will be delayed once again.

The latest setback, which will push back the unit's in-service date to July, is due to a "degraded hydrogen seal" on the generator side of the unit. The problem was discovered in the final stages of startup testing, as engineers raised and lowered the power to ensure safety.

The company previously said it had expected the unit to be operational in June.

More: *The Atlanta Journal-Constitution*

IOWA

Linn County Extends Solar Moratorium

The Linn County Board of Supervisors last week extended its moratorium in accepting new applications for utility-scale solar installations through Sept. 30 for the last time before the board adopts a new code governing the projects.

The board unanimously voted to extend the moratorium, which was set to end June 30, as staff prepare new code language based on the work of renewable energy review committees. Any changes would not apply to previously approved projects.

More: *The Gazette*

MISSOURI

Evergy to Roll Out Time-based Rate Method

Evergy will roll out a series of new time-based rate plans that adjust the price a customer pays for electricity based on the time of day it is used.

The company said all state customers will be impacted by the change and will need to enroll in one of four plans starting in October.

More: *WDAF*

NEW MEXICO

Environment Department Fines Ameredev $40M for Excessive Flaring

The Environment Department last week announced a $40.3 million penalty against oil producer Ameredev for disobeying local pollution reporting and control requirements by burning off vast amounts of natural gas in a prolific energy-production zone.

The department claimed the burning caused excessive emissions in 2019 and 2020 at five facilities in Lea County. It also alleged that Ameredev mined oil and natural gas without any means of transporting the gas away via pipeline, as is required by state law. The company instead is accused of burning off the natural gas in excess of limits or without authorization.

The department has ordered the company to cease all excess emissions and seek permits that accurately reflect its operations, with verification from an independent auditor.

More: *The Associated Press*

OHIO

Dayton Approves Solar Project

The Dayton City Commission last week approved the 253-acre Gem City Solar project that will consist of 22,000 panels.

The project will also include vegetation management operations and maintenance plans to ensure safe and reliable upkeep.

Construction is set to begin late in 2024, with the goal of being operational in 2025.

More: *WDTN*

VIRGINIA

Norfolk Council Approves Solar Farm on Landfill

The Norfolk City Council last week unanimously approved a 35-acre solar farm that will sit on the site of the former Campostella Landfill that closed in 1996.

The project is being developed by the Community Power Group.

More: *WAVY*

National/Federal news from our other channels

Stakeholders Respond to ERO Budget Drafts

ERO Insider

White House Sets 2025 Cybersecurity Priorities

ERO Insider

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