RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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May 26, 2020

FERC Ups MISO TO ROE, Reverses Stance on Models

By Amanda Durish Cook

FERC last week lifted MISO transmission owners' base return on equity from 9.88% to 10.02% and allowed them to add a third calculation model into the mix.

In approving the new methodology, FERC walked back its own arguments last year against incorporating the risk premium model (RPM) into ROE calculations along with the discounted cash flow (DCF) and capital asset pricing models (CAPM) (*EL14-12, et al.*).

Thursday's ruling makes the 10.02% ROE effective Sept. 28, 2016, superseding the 9.88% and 10.32% ROEs approved in 2019 and 2016, respectively. Those figures were at different times intended to replace the 12.38% ROE established in 2002, which FERC deemed excessive years ago.

The ROE for MISO TOs is now capped at 12.62%, including incentives.

The commission used both DCF and CAPM when it set the TOs' ROE at 9.88% last year. The move was met with consternation and confusion from TOs, who questioned FERC after it hinted at using four models to determine ROE. (See *TOs Challenge New MISO ROE Rules* and *FERC Adopts ROE Methodology in MISO Complaints*.) At the time, FERC said RPM, which estimates cost of equity using the premium that investors expect to earn on a stock investment over the return they expect to earn on a bond investment, was "largely redundant with the CAPM," though less accurate and "would confer too much weight towards risk premium methodologies."

On rehearing six months later, FERC found "the flaws for the risk premium model, when mitigated by certain adjustments, do not render use of the model unreasonable." The commission now says it will institute a zone of reasonableness in the RPM — a value it doesn't naturally produce — using an average of the zones of reasonableness from CAPM and DCF. FERC also said it will eliminate certain cases from the risk premium analysis, such as

Continued on page 13

SPP, Stakeholders Honor Nick Brown in Retirement

Nick Brown in 2019 (p.35) | © *RTO Insider*

NJ Regulators Weigh Input on Capacity Market Exit

By Michael Yoder

The New Jersey Board of Public Utilities received dozens of comments Wednesday on whether to leave the *PJM* capacity market in response to the expanded minimum offer price rule (MOPR).

Forty *filings* were made by the May 20 deadline set by the BPU, which initiated the investigation in March to determine if staying in the capacity market will increase consumer costs or impede Gov. Phil Murphy's goals of 100% clean energy sources by 2050 (Docket No. *EO20030203*). (See *N.J. Investigating Alternatives to PJM Capacity Market*.)

Some stakeholders said the state should adopt the fixed resource requirement (FRR) because the expanded MOPR would hamstring its support for emission-free generation. Opponents said leaving the capacity market could end up costing state ratepayers millions, leaving them at the mercy of monopolistic generators.

PJM's Independent Market Monitor released a *report* May 13 that concluded a statewide FRR would increase costs by almost 30% if prices were at the RTO offer cap of $235.42/MW-day but only 2.4% if prices equaled the $186.16/MW-day weighted average price for the state in the most recent Base Residual Auction. (See *PJM Monitor Finds Capacity Exit Costly for NJ*.)

Two clean energy advocates responded with a report criticizing the Monitor's analysis, saying it was skewed by assumptions that FRR re-

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Also in this issue:

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In this week's issue

FERC/Federal News

Chatterjee Pledges to Serve Full FERC Term

'Goofing Around' with Mention of Potential Gubernatorial Bid

By Rich Heidorn Jr.

FERC Chairman Neil Chatterjee | © *RTO Insider*

FERC Chairman Neil Chatterjee pledged Thursday to serve his full term, saying his Facebook post suggesting he was considering a run for governor of Virginia was intended as a joke.

Chatterjee, a former aide to Senate Majority Leader Mitch McConnell (R-Ky.), who has long been rumored to have political ambitions, created a Facebook *group* titled "Hypothetical: Draft Neil Chatterjee for Virginia Governor 2021" on May 16. (See *Chatterjee Exploring Va. Gubernatorial Race*.)

"Let me just be totally, totally clear on this, and I can't stress this enough. What I did was write a light-hearted post to social media. It was clearly a joke and not serious," he said in response to a question at his press conference after FERC's monthly open meeting. "I cannot stress enough [that] my focus is on the work of the commission. I'm not focused on anything about my future until after the completion of my term at the commission, June 30, 2021. Period. Point blank."

The filing deadline for the Virginia primary is April 25, 2021, more than two months before Chatterjee's term expires. Under the Hatch Act, Chatterjee would be required to relinquish his FERC position before seeking office in a partisan election or soliciting political contributions. Gubernatorial candidates must obtain 10,000 signatures to get on the ballot in Virginia.

Chatterjee said it was clear fellow Commissioner Richard Glick wasn't taking his potential candidacy seriously. After making opening remarks at Thursday's meeting, Chatterjee invited comments from Glick, who said jokingly, "Thank you, governor, I mean, Mr. Chairman."

Nevertheless, Chatterjee's Facebook group had attracted more than 300 members as of Thursday, and none of those who pledged their support and campaign contributions seemed to be aware it was meant as a lark.

"I was joking around with my friends on my personal social media to try to get a reaction from [them]," Chatterjee said when asked whether he was concerned that his posting could cause confusion. "It was not something that was in any way meant for the broader public. Maybe I should have spent more time building pillow forts. There [are] only so many pillow forts you can build. I was goofing around."

Under questioning, the chairman declined to say unequivocally that he would not be running for governor next year, repeating, "I will serve my term until June 30, 2021." ■

CAISO/West News

Improper Email Delays CPUC Vote on PG&E Plan

CPUC President Expresses Displeasure at Postponed Decision on Reorganization

By Hudson Sangree

The California Public Utilities Commission unexpectedly postponed its planned vote Thursday on Pacific Gas and Electric's bankruptcy reorganization plan because a party to the proceedings improperly sent out a mass email earlier in the week.

"This proposed decision is being held because a party sent an *ex parte* communication by email on Tuesday," President Marybel Batjer said. "This was a prohibited *ex parte* communication under state law and the CPUC rules of procedure."

The CPUC was planning to vote on an administrative law judge's decision to approve PG&E's Chapter 11 plan with some modifications, including enhanced oversight by the commission.

Batjer angrily denounced the party's action and warned of possible consequences for issuing a communication during a required quiet period from May 15 until the Thursday vote.

"For my part, I am not pleased that an error in understanding our rules or a disregard for them will delay the vote on a proposed decision," Batjer said. "We will implement this delay to ensure that we have very clearly taken the procedural steps we need to take to ensure we issue a legally sound decision."

The email was sent by William Abrams, a wildfire victim and party to the CPUC proceedings, who sent an email with attached documents to hundreds of individuals on the CPUC's service list.

"This is to notice the commission and parties of this proceeding regarding my objections and those of the [Tort Claimants Committee] filed in the U.S. Bankruptcy Court (Case #19-30088-DM)," it said in part.

CPUC President Marybel Batjer

Abrams has represented himself in the bankruptcy court proceedings and has urged delay to more closely examine PG&E's reorganization plan. He apologized in a notice to the CPUC on Wednesday.

"My understanding was that posting publicly available documents to the docket for this proceeding was not a violation of the quiet period," Abrams said. "However, I apologize if this was not in keeping with policies and procedures of this proceeding and of the commission."

Batjer gave parties, including PG&E, a chance to respond to the email until midnight Thursday and insisted that the commission's rules against *ex parte* communications during the "quiet time" before a vote be strictly obeyed.

"We will not tolerate any further delay to this proceeding," Batjer said.

The CPUC could pursue "remedial action" if it finds a party intentionally delayed the vote, she said.

The vote will now be held this Thursday, one day after a hearing is scheduled to start in the U.S. Bankruptcy Court in San Francisco on PG&E's Chapter 11 plan. The quiet time for the next hearing began Friday and will last until the conclusion of the hearing, she said.

PG&E needs the bankruptcy court and CPUC to approve its reorganization plan by June 30 in order to participate in a state insurance fund for future wildfires. Massive fires sparked by its equipment caused PG&E to seek bankruptcy protection in January 2019. ■

CPUC headquarters in San Francisco | © *RTO Insider*

CAISO/West News

FERC Partly Rejects CAISO Deliverability Enhancements

By Hudson Sangree and Robert Mullin

Longhorn cattle graze below transmission lines in Northern California. | © *RTO Insider*

FERC last week partly rejected CAISO Tariff revisions seeking deliverability enhancements for interconnection customers, saying a proposal to limit self-scheduling by some generators wasn't reasonable (*ER20-732*).

The revisions sought by CAISO in a January filing were a response to the increasing impact of net peak demand shifting to later in the day, after solar goes offline, and a desire to avoid curtailing wind and solar resources because of transmission congestion during off-peak hours.

In particular, the ISO wanted off-peak generators to qualify for the same kinds of system enhancements traditionally given to on-peak generators to ensure resource adequacy (RA) under the program administered by the California Public Utilities Commission.

As FERC noted May 19, the CPUC's program "determines how much resource adequacy capacity a given generator can reliably provide and assigns each generator technology a monthly 'qualifying capacity' based on the generation technology and expected load conditions, but without considering potential transmission constraints." That means a conventional generator would have a qualifying capacity equal to its total capacity for all months of the year, but a solar resource's qualifying capacity would depend on the time of year.

To account for system constraints, CAISO calculates each generator's "net" qualifying capacity, which adjusts the CPUC's qualifying capacity to account for the expected load and energy flows on the transmission lines a generator uses to deliver its output to consumers.

The CPUC revised its method for calculating qualifying capacity in 2018, significantly reducing the RA values for solar resources. The change also complicated CAISO's ability to finance the costs of transmission upgrades needed to maintain system deliverability during peak conditions at a time when solar represents about 60% of the interconnection queue.

The ISO requires generators submitting interconnection requests to choose one of three statuses to indicate what portion of a resource's output is deliverable under peak system conditions: full capacity, partial capacity or energy only. Energy-only resources are only deliverable subject to grid conditions and are not eligible to be counted as RA capacity.

Currently, CAISO conducts on-peak and off-peak deliverability assessments for generators seeking to connect to the ISO's system, FERC explained. The on-peak assessment determines what network upgrades are needed to deliver the resource's full output.

"However, the off-peak assessment is currently for informational purposes only because, according to CAISO, deliverability concerns principally relate to resource adequacy, and therefore peak demand," FERC said. "Generators' ability to deliver energy off-peak has not historically been a concern warranting developers' financing network upgrades to relieve constraints."

But that's changing in CAISO as solar delivers increasing amounts of energy during off-peak hours midday. The ISO asked to create an off-peak deliverability status to identify and finance needed network upgrades and to grandfather in all generators that sought off-peak status. Those that didn't seek that status would not be allowed to self-schedule in CAISO.

FERC accepted the ISO's off-peak upgrades proposal.

"We find that CAISO's proposal to identify off-peak network upgrades in the interconnection process to relieve local transmission constraints and allow generators to finance them, rather than potentially waiting years for solutions to develop in the transmission planning process, is reasonable," FERC said. "We note that on-peak delivery network upgrades where generators choose to finance such upgrades to obtain deliverability status to provide resource adequacy are also undertaken through the interconnection process, not the transmission planning process.

"Thus, we find that it is just and reasonable to include in transmission rates the costs of off-peak upgrades to address local constraints, consistent with the inclusion of costs for on-peak upgrades that address local constraints."

But FERC rejected the limitations on self-scheduling for generators that don't opt in to seeking off-peak deliverability status.

"We find that CAISO has not adequately supported its proposal to give a self-scheduling benefit to interconnection customers with off-peak deliverability status, while restricting self-scheduling for other resources solely for the sake of preventing free-ridership," FERC said. "CAISO has not justified why some interconnection customers should receive the proposed self-scheduling benefit in the energy market for upfront funding of transmission upgrades whose costs are eventually rolled into transmission rates and borne by all transmission customers, while other interconnection customers do not." ■

CAISO/West News

PG&E Bankruptcy Nears Conclusion

California PUC Investigation Wrapping Up Also

By Hudson Sangree

Bankruptcy Judge Dennis Montali (top left) and lawyers in the PG&E bankruptcy discuss confirmation proceedings May 19.

Proceedings to conclude the sixth-largest bankruptcy in U.S. history will likely happen via video starting Wednesday, the judge overseeing PG&E Corp.'s Chapter 11 reorganization said last week.

Judge Dennis Montali, with the U.S. Bankruptcy Court in San Francisco, conducted a virtual hearing using Zoom on May 19 in which he spoke from his home with a dozen lawyers in New York, California and elsewhere. The remainder of hearings in the PG&E bankruptcy case will probably also be held via video because of the COVID-19 crisis, he said.

The purpose of the May 19 hearing was to establish the schedule for proceedings to approve or reject PG&E's $60 billion reorganization plan, including the $13.5 billion it has promised to some 80,000 victims of wildfires sparked by its equipment in recent years.

Fire victims and other creditors, about 250,000 in all, had to cast their ballots on the plan by May 15. A two-thirds vote is required for approval.

Late Friday, Prime Clerk and PG&E filed lengthy documents with the court detailing the voting results. Wildfire victims voted by an 85% majority to approve PG&E's Chapter 11 plan, and the other creditors overwhelmingly supported it too.

"Fire victims have spoken, and they have spoken loudly and resoundingly in favor of the plan. The time has come to confirm the plan," PG&E said in its filing.

Trial Starts Wednesday

The "confirmation" trial of PG&E's plan is scheduled to start Wednesday. After hearing from attorneys for all major parties, Montali will have to decide whether to approve PG&E's reorganization proposal.

PG&E is trying to exit bankruptcy by June 30 to meet the requirements of Assembly Bill 1054, a measure pushed through the State Legislature by Gov. Gavin Newsom last July that creates a $21 billion fund to insure utilities against future wildfires. California law holds utilities strictly liable for wildfires sparked by their equipment.

May 15 also was the deadline for parties to file objections to the plan. Dozens did so, including the state and federal governments, the U.S. Trustee in the bankruptcy case, and the city and county of San Francisco. They questioned provisions in the plan that they say could exculpate PG&E, its fiduciaries and associates for actions they take after the bankruptcy case has ended.

The Tort Claimants Committee (TCC), which represents fire victims, objected to the plan based on a lack of assurances that the $6.75 billion in PG&E stock, intended to fund half of the victims' trust as part of a negotiated settlement agreement, will hold its value amid the coronavirus pandemic and potential wildfires this summer and fall.

"The plan … fails to provide fire victims with the treatment and value that was agreed to in the settlement," the TCC wrote. "Instead, the plan has whittled away various aspects of the settlement and could harm fire victims in amounts that are in the billions of dollars."

PG&E lawyers told the judge May 19 that negotiations and mediation are underway that could resolve the objections before Wednesday's confirmation hearing.

CPUC to Vote Thursday

The California Public Utilities Commission is scheduled to vote on PG&E's reorganization plan Thursday, wrapping up an investigation that began in September. The vote was delayed a week after a party to the proceeding sent an improper *ex parte* email, the CPUC said. (See related story, *Improper Email Delays CPUC Vote on PG&E Plan*.) AB 1054 tasked the commission with ensuring PG&E's plan is in the public interest, including "the electrical corporation's resulting governance structure … in light of [its] safety history, criminal probation, recent financial condition and other factors deemed relevant."

A *proposed decision* by a CPUC administrative law judge recommended approving the plan as long as PG&E agrees to enhanced oversight and enforcement by the commission. The utility has said it will accept the changes, and it agreed earlier this month to pay a record $1.9 billion in penalties levied by the CPUC. (See *CPUC, PG&E Agree to Record $1.9B in Penalties*.)

Sentencing Ahead

The utility has said it intends to plead guilty to 84 counts of involuntary manslaughter and one count of starting an illegal fire stemming from the Camp Fire in November 2018. State investigators determined a PG&E transmission tower ignited that blaze, the deadliest and most destructive wildfire in state history, which destroyed much of the town of Paradise.

The Butte County District Attorney has said that PG&E's sentencing hearing will be held on June 16 and streamed live on the Butte County Superior Court's YouTube channel.

PG&E remains on criminal probation for six felonies related to the San Bruno gas pipeline explosion in September 2010. ■

ERCOT Briefs

Staff Publishes COVID-19 Long-term Load Forecast

ERCOT's new *long-term load forecast* for COVID-19 scenarios based on data provided by Moody's Analytics indicates the Texas grid operator will continue to see a loss of demand into 2024.

Requested by stakeholders, the forecast relies on demand and energy data from adjusted peak load forecasts — based on historical weather years — that correlates with Moody's economic forecast. Stakeholders can use the information to perform their own analyses, the grid operator said.

The scenarios used the updated Moody's base COVID-19 scenario (P90 forecast), which projects a 2024 peak demand of 84.3 GW. ERCOT's 2020 long-term forecast foresees an 87.1-GW peak demand.

The scenarios include:

- a 90th percentile summer noncoincident peak by weather zone;
- ERCOT's various peak demand scenarios;
- noncoincident peak forecast by weather zone;
- ERCOT monthly peak demand and energy forecasts; and
- coincident peak forecast by weather zone.

ERCOT is still publishing its weekly analysis of COVID-19's effect on load. Its latest report indicates the grid operator was still seeing a 3 to 4% load reduction through May 10.

TMPA's Gibbons Creek coal plant could soon be roaring back to life. | *Texas Municipal Power Agency*

Plants Enter, Exit Mothballs

ERCOT will be losing 105 MW of year-round capacity after this summer, but it could also be adding 420 MW of capacity in 2021.

Austin Energy on May 19 told ERCOT it plans to mothball its 105-MW, wood-fired Nacogdoches Power facility in East Texas, returning it for seasonal operations from May 15 to Oct. 15. The facility is the largest biomass plant in the U.S.

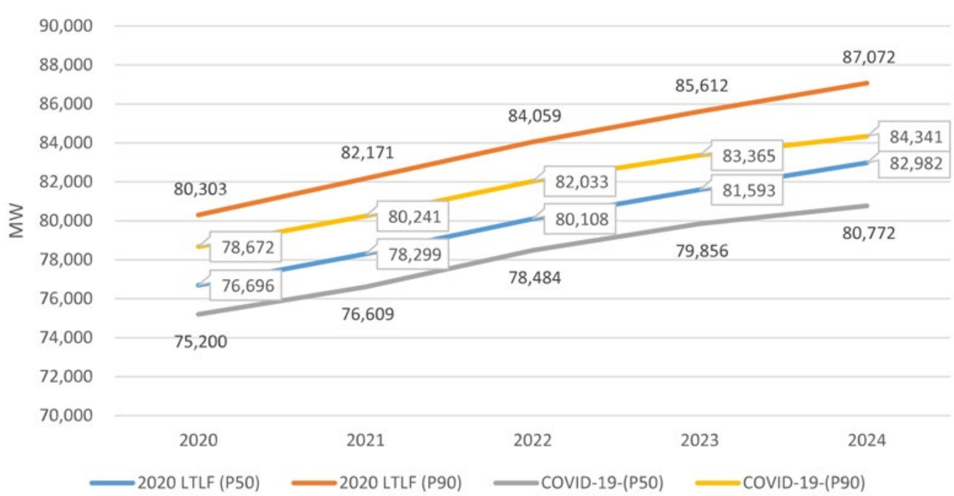
However, the grid operator has included the 420-MW coal-fired Gibbons Creek Generating Station, which was shut down last June, in its *long-term assessment* for 2021. The plant is expected to resume operations before next summer. (See *Texas PUC Responds to Shrinking Reserve Margin*.)

ERCOT said Gibbons Creek has met all criteria for inclusion in its capacity, demand and reserves (CDR) report, including an interconnection agreement signed by its current owner, Texas Municipal Power Authority. The agency operates the plant on behalf of the cities of Bryan, Denton, Garland and Greenville.

TMPA is in negotiations to sell the plant. In its report, ERCOT lists the "interconnecting entity" as TEERP Power Station.

Austin Energy acquired Nacogdoches Power from Southern Power last year. It has a 20-year power purchase agreement for the plant's energy that expires in 2032. ■

— Tom Kleckner



ERCOT's long-term forecast (blue and orange lines) compared to those based on Moody's COVID-19 economic projections (yellow and gray lines) | *ERCOT*

ISO-NE News

ISO-NE Planning Advisory Committee Briefs

NESCOE 2019 Economic Study Update

Preliminary results from an ISO-NE study show that the quantity of reserves needed in an increasingly renewable future will be a function of how well semi-dispatchable resources can be curtailed, the Planning Advisory Committee heard on Wednesday.

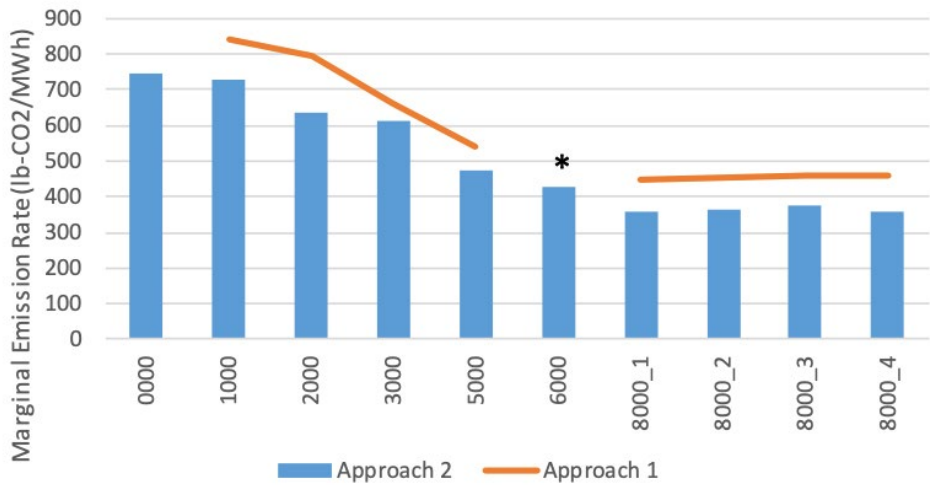
Patrick Boughan, ISO-NE senior engineer for resource studies and assessments, *presented* that finding during a discussion of the ancillary services and marginal unit emissions components of the New England States Committee on Electricity's requested 2019 Economic Study. (See *ISO-NE Planning Advisory Committee Briefs: April 23, 2020*.)

The RTO employed Dartmouth College's Electric Power Enterprise Control System (EPECS) simulation tool for the study, with modifications and improvements made to the software program since it was previously *reviewed* with the PAC in December 2017, he said.

The analysis reviews both the use of select reserves currently required by ISO-NE, such as a 10-minute spinning reserves, as well as other types of reserves that are not required but have physical qualities that can be tracked and analyzed, such as load-following reserves.

NESCOE, Anbaric and RENEW Northeast last year each requested separate studies from ISO-NE. (See "Modeling More Offshore Wind, Slowly," *ISO-NE Planning Advisory Committee: March 18, 2020*.)

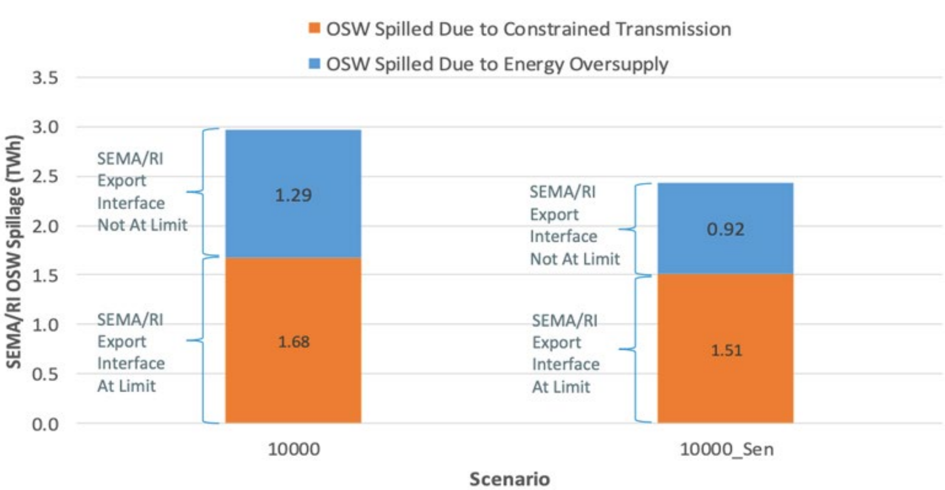
Regarding ancillary services, NESCOE in its initial study request said, "As the market needs change, new grid opportunities may be identified to address challenges, including load following, regulation, operating reserves and operation during low-load periods."



Drawing from both approach methods, the NESCOE study finds that 30 to 40% of the emissions reductions come from high CO2-emitting municipal solid waste and coal generators, even though they are marginal less than 5% of the time. | *ISO-NE*

NESCOE said its study request conformed with the Tariff, "as it considers the potential economic benefits of relieving transmission constraints and shows the benefits of interconnecting increasing amounts of offshore wind in alternative locations."

EPECS assumes semi-dispatchable resources are infinitely curtailable to maximum amounts, but if this assumption is revised, more reserves will be needed, the report said.



For the Anbaric 10000 and 10000_Sen scenarios, OSW interconnected into SEMA and RI areas was spilled because of either constrained SEMA/RI export interface or energy oversupply. | *ISO-NE*

Estimated Marginal Emissions

Boughan said the RTO developed two ways to calculate marginal unit emissions for the NESCOE study and developed two complementary analyses using outputs from GridView, a software program that simulates the economic operation of power systems in hourly intervals for periods ranging from one day to many years.

This varies from how the marginal resource is determined for the annual marginal emissions analyses (MEA) conducted by the RTO; however, using the GridView model allows analysis of future scenarios that are not available via the MEA method, Boughan said.

One approach to determining marginal unit emissions compares results of two scenarios with different amounts of wind, calculating the change in annual emissions per additional megawatt-hour of energy produced by offshore wind.

The second approach is to find the most expensive generator able to respond to dispatch signals — the "implied" marginal unit, which sets marginal emissions, the report said.

By analyzing only cases without transmission constraints, the RTO was able to cleanly quantify the change in CO_2 emissions because of offshore wind production additions. There is only a small change in annual emissions and megawatt-hours because of transmission constraints caused by offshore wind, and internal interfaces create difficulties for determining the most expensive generator, Boughan said.

ISO-NE News

Drawing from both methods, the NESCOE study finds that 30 to 40% of the emissions reductions come from reduced dispatch of high CO_2-emitting municipal solid waste and coal generators, even though they are marginal less than 5% of the time.

The study also observes that municipal solid waste resources may not, in reality, be marginal generators because of the other services they provide.

The second approach, implying marginal emissions in GridView simulations, provides a slightly lower estimated marginal CO_2 emission rate than observed from the first approach, comparing two simulations with different amounts of offshore wind.

The study concluded that results from GridView simulations do not exhibit the range of marginal units that a historical locational marginal unit analysis would contain.

Not only does GridView not apply bidding strategies to resources, but results from the simulations do not exhibit the range of marginal units that a historical locational marginal unit analysis would contain. Resources such as energy storage charging and discharging are price takers and are never identified as marginal. Only natural gas, coal, municipal solid waste and wood-fired units are seen to be marginal.

ISO-NE will continue studying ancillary services in the 2020 Economic Study to further determine the needs of the system and will work with the PAC to confirm the assumptions needed, Boughan said.

The RTO's next steps are to publish the final NESCOE study by July 1, the final Anbaric study in June or July and the final RENEW report by July.

Anbaric 2019 Economic Study Follow-up

The addition of 8,000 to 12,000 MW of offshore wind plus assumed resource retirements resulted in Southeast Massachusetts/Rhode Island (SEMA/RI) export interface constraints, the PAC heard during a follow-up to the March presentation on the Anbaric 2019 Economic Study.

Haizhen Wang, the RTO's lead engineer for resource studies and assessments, presented *preliminary* results that show natural gas-fired resources were required to partially replace retired nuclear generation in all Anbaric scenarios.

Because of its intermittent nature, offshore wind does not follow loads, and the study illustrates intervals when demand is high but offshore wind is low, especially during summer, Wang said.

2020 Economic Study Scope, Assumptions

ISO-NE Manager of Resource Studies and Assessments Peter Wong *presented* the first of two presentations planned on the 2020 Economic Study draft scope of work and high-level assumptions for production simulations.

National Grid requested the study to model year 2035 to provide insight into wholesale energy market impacts, unit economics, utilization of resources, and the role of bidirectional transmission capability and battery storage in meeting the needs of a system with a high proportion of variable resources.

Several stakeholders asked Wong about the assumed potential bidirectionality of the existing external ties, including the Highgate, HQ Phase II and New Brunswick interconnections. The study proposes to "treat them as bidirectional, if physically capable, with a focus on Hydro-Québec, given the likelihood of coupled supply and load in New York."

"If the 1,200 MW from the New England Clean Energy Connect [NECEC] is essentially base-loaded, if you had export over Phase II to do the type of spillage absorption … doesn't that just mean that we're backing down on the amount of NECEC exports, since on a net-interchange basis the control area is just reducing the amount of its imports?" asked Tom Kaslow of FirstLight Power Resources.

NECEC is a $950 million project to deliver 1,200 MW of Canadian hydropower to the New England grid in Lewiston, Maine, along a 145-mile transmission line controlled by Avangrid subsidiary Central Maine Power.

The study will neither include an assessment of FCM outcomes nor ancillary service prices, Wong said.

"This study requires that numerous resource types of different sizes and locations be added to the system, making it nearly impossible to develop any meaningful results without lots of effort and also many assumptions," Wong said.

For example, the large quantities of solar generation are dispersed projects for which the interconnection studies are being done through the distribution utilities interconnection process, and "we don't have any good handle on what is needed," he said.

"And some of these storage facilities, well-sized and well-located standalone storage proposals should not be triggering the need for any substantial upgrades," Wong said.

The preliminary schedule for the 2020 Economic Study is to finalize production simulation assumptions for the three scenarios at the June/July PAC meeting; present draft production simulations results and identify sensitivity scenarios and assumptions in Q3; present sensitivity scenarios simulation results and draft ancillary services (EPECS) results in Q4; and present draft and final reports in the first quarter 2021. ■

— Michael Kuser

– Marginal emission rates seen decreasing as more OSW is added

Case	CO2 Amt (Short Ton)	OSW (TWh)	Onshore WT (TWh)	lb CO2 Reduction/MWh-Wind	Comparison
NESCOE_0000_UN	26,024,210	0.12	3.86		
NESCOE_1000_UN	24,371,943	3.94	3.86	865	NESCOE_1000_UN vs. NESCOE_0000_UN
NESCOE_2000_UN	22,860,825	7.99	3.85	747	NESCOE_2000_UN vs. NESCOE_1000_UN
NESCOE_3000_UN	21,583,677	11.83	3.84	668	NESCOE_3000_UN vs. NESCOE_2000_UN
NESCOE_5000_UN	19,587,901	19.28	3.81	537	NESCOE_5000_UN vs. NESCOE_3000_UN
NESCOE_6000_UN	19,661,730	22.28	3.80	NA (Heat Pump Load)	
NESCOE_8000_1_UN	18,458,845	27.61	3.79	453	NESCOE_8000_1_UN vs. NESCOE_6000_UN
NESCOE_8000_2_UN	18,475,588	27.56	3.77	501	NESCOE_8000_2_UN vs. NESCOE_6000_UN
NESCOE_8000_3_UN	18,529,299	27.27	3.77	372	NESCOE_8000_3_UN vs. NESCOE_6000_UN
NESCOE_8000_4_UN	18,431,950	27.62	3.78	547	NESCOE_8000_4_UN vs. NESCOE_6000_UN

The NESCOE 2019 Economic Study says annual average marginal emissions can be calculated using simulation results. | *ISO-NE*

ISO-NE News

NEPOOL Reliability Committee Briefs

Load Forecasting Methods Evolving

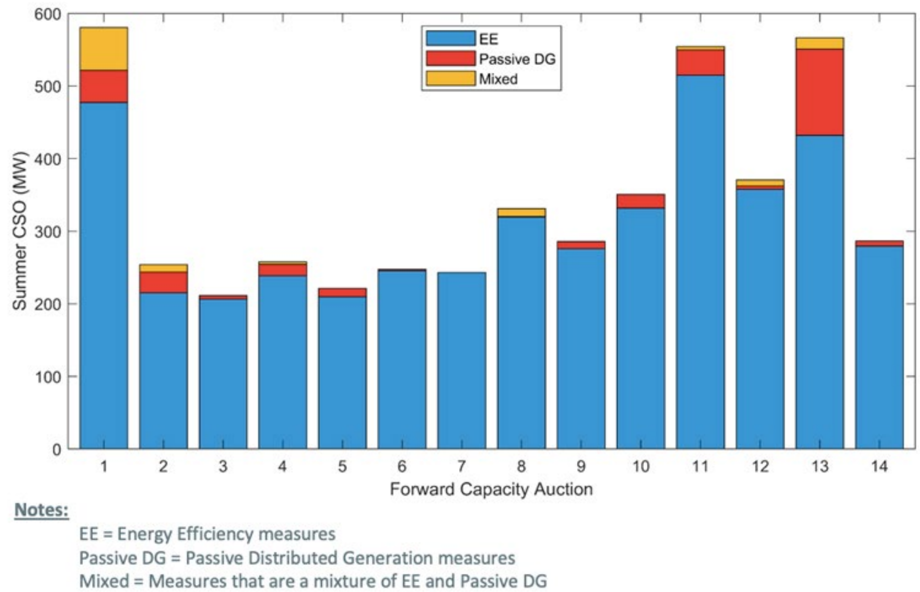
ISO-NE Load Forecasting Manager Jon Black updated the New England Power Pool's Reliability Committee last week on changes that will affect the participation of energy efficiency and other passive demand resources (PDRs) in the RTO's Forward Capacity Market. His presentation elaborated on remarks made to the committee in April. (See "EE Reconstitution," *NEPOOL Reliability Committee Briefs: April 22, 2020*.)

Black reviewed changes to the gross load forecast reconstitution *methodology*, which is used to prevent the double-counting of PDRs in the RTO's Forward Capacity Auction.

PDRs receive compensation as a supply-side resource and reduce demand, thus their demand-reducing impact becomes embedded in historical load data. To ensure that PDRs are not double-counted, the RTO must add — or reconstitute — PDR demand reductions into historical loads used in the development of a forecast of future loads.

EE measures comprise the majority of PDR energy, Black said. However, some EE measures expire, which also requires reconstitution of the load forecast data.

"When we say expiring measures, we're referring to EE measures that have reached the end of their useful measured life and can no longer participate in FCM as supply," Black said. "Some of the lingo in the industry is that there will be no backsliding."

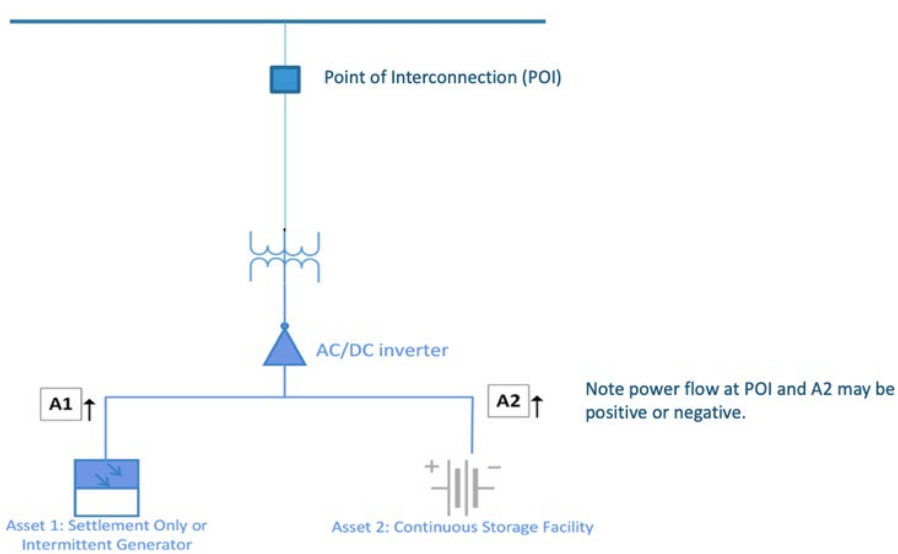


Composition of new passive demand resources | *ISO-NE*

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

ISO-NE will present the load forecasting methodology changes to the RC for an advisory vote in June. Upon approval by NEPOOL's Participants Committee, the RTO will file the Tariff changes with FERC with a requested effective date of Aug. 30.

The change in load forecasting methodology is the first of three related initiatives the RTO introduced to relevant NEPOOL technical committees so far this year. The second initiative considers the impact of behind-the-meter solar PV on future planning assessments. The third is intended to better integrate the FERC Order 1000 solicitation process into the reliability delist bid review, starting with FCA 15.



DC-coupled facility registered as two assets | *ISO-NE*

Changes to PP10 for Tx Solution

The RC approved changes to Planning Procedure 10 (*PP10*) to provide implementation details for the alignment of reliability reviews of delist bids with the competitive transmission solution process. It recommended that the PC support the revisions at its next meeting June 4.

ISO-NE Director of Transmission Services and Resource Qualification Al McBride *presented* the proposed changes to "better describe how responses in the competitive solicitation process that meet certain conditions may be accounted for in the review of rejected delist bids under Section 7.5 of PP10."

The RTO presented and discussed the proposal at the April 22 RC meeting.

If approved, the changes would not affect the outcomes of the selection processes stemming from Order 1000, nor would they have any effect on how new resources participate in the FCM, McBride said. They are intended to

ISO-NE News

prevent unnecessarily retaining a resource for reliability if transmission responses in the competitive solicitation process address the reliability need.

Metering for DC-coupled Assets

ISO-NE Manager of Demand Resource Administration Doug Smith presented changes to Operating Procedure 18 (*OP-18*) that would enable DC-coupled facilities to participate in the markets as separate assets. The proposed redline changes attempt to leverage existing processes while ensuring that metering and telemetry for DC-coupled facilities meet the same standards that apply to other generating facilities.

The RTO proposes the changes become effective in the third quarter because some DC-coupled facilities are likely to be commercial by then. Several market participants are installing electric storage and intermittent generation behind the same point of interconnection. Some of those "co-located" facilities are DC coupled, meaning that both the storage and intermittent components share one or more inverters, thus the need to address the metering of such assets.

ISO-NE will bring the matter back for an advisory vote in June.

Committee Actions

The RC's notice of *actions* included approval of several motions, noting that all sectors had a quorum.

The committee approved a cluster of projects in Western Massachusetts for National Grid (NEP-20-G03), including 96 state-jurisdictional projects and 19 associated transmission power purchase agreements.

High-definition cameras on drones allow Eversource Energy line inspectors to see possible damage from all angles and take better photos. | *Eversource*

National Grid also won approval for a cluster study in Rhode Island (NEP-20-G04), composed of 39 state-jurisdictional projects and two associated transmission PPAs.

The RC approved a pool transmission facility (PTF) cost allocation of $375 million to Eversource Energy for transmission upgrade costs on 27 separate projects in Connecticut, Massachusetts and New Hampshire.

Eversource also had $7.5 million in PTF cost allocations approved for work associated with the replacement of 25 wooden structures on the 345-kV 371 line and $11.8 million in PTF cost allocation approved for work associated with the replacement of 55 wooden structures on the 345-kV 321 line.

The RC also approved a revision to Operating Procedure 12 (*OP-12*) related to voltage and reactive control, recommending that the PC support the revisions at its June 4 meeting. ■

— Michael Kuser

MISO News

MISO Utilities Urge Swift Action on Gen Mix

By Amanda Durish Cook

Utility executives participating in a virtual panel last week urged MISO to prepare now for the changes sweeping the grid with the increased adoption of renewable and distributed resources.

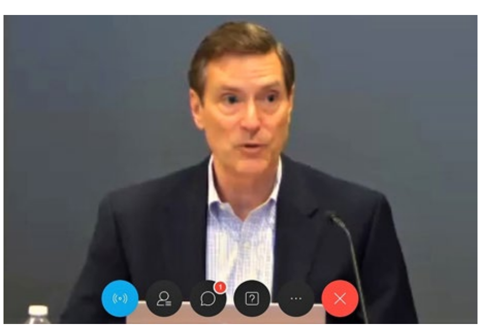
The online event Thursday riffed off the findings from MISO's second annual Forward Report released in March, which concluded that the RTO needs to adjust its capacity construct and offer new market products as soon as possible to accommodate a resource mix with a plurality of renewables coming in 2030. (See *MISO Forward Report Stresses Near-term Change*.)

Following the report, MISO staff said they will soon need to break out the RTO's annual loss-of-load-expectation study and Planning Resource Auction by season. The RTO said it could begin making filings to move toward a seasonal resource adequacy construct late this year and in 2021. MISO said it will also need a re-evaluation of its scarcity and emergency pricing. (See related story, *FERC Rejects Complaints on PJM Seasonal Resources*.)

The report was framed from the perspective of five hypothetical MISO utilities and what they will need from a grid operator in the near future.

"Customers have a sense of urgency. They know change is coming to their companies. … They're making investment decisions, and they need help," MISO Executive Vice President of Market and Grid Strategy Richard Doying said during the virtual workshop.

By 2030, MISO *predicts* its generation mix will contain 32% renewables, 28% natural gas, 27% coal and 9% nuclear. In 2018, the RTO's generation mix was fueled by 47% coal, 27% natural gas, 15% nuclear and 8% renewables. MISO officials have emphasized that the 2030 mix isn't an RTO forecast but based on utilities' announced plans.


MISO's Richard Doying speaks during the May 21 virtual conference.

Doying said the renewable-heavy outlook means MISO must establish new reliability criteria that capture risks across the entire year, not just for one peak summer day.

He also said MISO needs visibility on — but not control over — distributed resources to understand how they affect demand.

"MISO does not want to become a distribution operator. That is far beyond what a central grid operator should do," Doying said.

In live polling conducted during the workshop, many stakeholders said MISO should be prepared to roll out changes — new reliability criteria, redefined markets, updated transmission planning criteria and better distribution asset communication — by 2025. A few even said MISO should implement plans by 2023.

"We really have to start now to keep that reliability and system efficiency," Vice President of System Planning Jennifer Curran said.

Cooperative Energy COO Nathan Brown said his co-ops are increasingly seeing the need for resources to respond more flexibly to system conditions. Brown said MISO's market currently doesn't put a monetary value on flexibility and that the approximately 550-day interconnection queue isn't conducive to getting nimble generation on the system quickly.

Xcel Energy Senior Vice President Teresa Mogensen noted her company is working toward a carbon-free goal by 2050.

"It will take support from MISO and transmission and markets and state regulators," she told RTO executives.

She also said technologies are not "completely mature today to deliver 100% carbon-free energy reliably."

"Everything is built on the way things were. … We need to look at things with a new eye," she said, citing the familiar disclaimer: "Past performance doesn't guarantee future results."

Mogensen said MISO must develop a more accurate and prolonged forecast that can predict needs a few days in advance.

Innovation on the March

NextEra Energy Resources Vice President Mark Ahlstrom had a sunnier outlook on renewable capability. He foresees a digital revolution where "virtual" power plants erase the intermittent nature of renewable resources.


Mark Ahlstrom, NextEra

"Once you pair software with your product, you can do amazing things," Ahlstrom said. "I think we have to get buckled in for a time of transition."

Ahlstrom also predicted that technology will make renewable generation extremely responsive sooner than anyone can project.

"I think just about everyone is vastly underestimating how much flexibility" will be achieved, he said.

Consumers Energy Vice President Timothy Sparks said that by 2030, parts of the MISO footprint could be operated "a little closer to the edge" with smaller reserve margins because of rapid-response load modification.

Voltus CEO Gregg Dixon said MISO needs a market interface "with very clear rules" that can facilitate the participation of "hundreds of thousands" of distributed energy resources. Voltus operates a virtual power plant, which offers demand response into MISO from its commercial and industrial customers.

State regulators must rethink their "outdated" practice of subsidizing load-modifying resources at ratepayer expense and turn to the "socialized benefits of a wholesale market" that they already signed up for, Dixon said.

"It's not so much the technical issues. It's the regulatory issues," Dixon said. But he added that MISO needs to prepare a platform where states can tap into a wider array of DR services. He said the choice for grid operators, states and utilities is to "be better and democratize the grid" or face customers choosing to disassociate for energy independence.

"History has shown that innovation will march forward regardless of the constructs we have put in place," Dixon said. ■

MISO News

FERC Ups MISO TO ROE, Reverses Stance on Models

Continued from page 1

those TOs that joined MISO and received the prevailing 12.38% ROE before FERC analyzed the reasonableness of that rate.

Several TOs called the 9.88% base ROE too low to attract investment and questioned why FERC would use the 2013 MISO proceeding as a platform to set policy when it had already collected opinions through a Notice of Inquiry. Many said using only two of the four financial models that the commission originally considered paints an incomplete picture of the information used to make transmission investments. Transmission and industrial customers, cooperatives, the Organization of MISO States, and the Mississippi and Missouri public service commissions petitioned the D.C. Circuit Court of Appeals in January over the ROE.

FERC's latest methodology still excludes the expected earnings model, the fourth model that the commission considered using prior to 2019. FERC said the model was flawed because it estimates returns based on a company's book value, not a return on the current stock price.

At the commission's open meeting Thursday, FERC Chairman Neil Chatterjee said the order doesn't exclude use of the expected earnings model in future proceedings. He described the new ROE methodology in glowing terms and said the changes strengthen the model to "better reflect investor expectations." The order creates "three equal ranges of presumptively just and reasonable ROEs that cover the entire zone of reasonableness."

"Orders like this one remind me of how excellent our staff is here at the commission," Chatterjee said.

Sharp Rebuke from Glick

However, Commissioner Richard Glick lambasted the commission's longstanding indecision on a just and reasonable ROE as he laid out its journey from preferring four financial models in 2018 to two in 2019 and now three. He said the uncertainty has "probably held back needed investment in the transmission grid."

Glick denounced the commission's turnaround in attitude on the RPM after "dismantling" it in the 2019 order.

"You might as well just say, 'Of course we should use the risk premium model!' After all, it increases MISO's transmission owners' ROE," Glick said during the meeting. He said public disapproval after the 2019 order led to Chatterjee "practically begging disappointed parties to seek rehearing" at the commission's December meeting.

| MISO

Glick also expressed annoyance at the commission for treating ROE composition as an "exact science."

"I think everyone knows this is more an art than a science," he said.

"We need to be aware that, as we continually tinker with our ROE methodology, we're losing sight of what is more important: a stable investment environment for transmission developers," Glick said. He said FERC's "tinkering" is sold as being dispassionate and technical, "but with each new twist, it becomes harder to buy that the commission is genuinely reassessing the mechanics of each model rather than disagreeing with the ROE numbers those models produce." He urged his fellow commissioners to bring "certainty and predictability" to how it sets ROEs.

Glick said his dissent to the order was only partial, as he found the 10.02% rate could actually be just and reasonable "despite the faulty reasoning."

What he really took issue with was FERC's inconsistent handling of ROE refunds, he said. The commission ordered MISO TOs to pay refunds for the period of November 2013 to February 2015 in response to the first complaint that the 12.38% ROE was excessive.

But FERC declined to grant refunds stemming from a second complaint lodged in 2015 that covered a period from February 2015 to May 2016, even though ratepayers paid the same 12.38% ROE that was deemed excessive. FERC explained that because the first complaint resulted in a 9.88% base ROE, that was considered the existing rate to investigate under the second complaint.

The commission also declined in its latest order to consolidate the two 15-month refund periods, saying granting more than one such refund period would exceed its authority.

Glick said in refusing to order refunds in one instance but not the other, the commission used "logic that only could make the authors of the Abbott and Costello 'Who's on First' routine proud." He said it simply boiled down to who paid what, not what rate was hypothetically in place at the time.

Although the 9.88% base ROE was previously ordered effective for September 2016, it didn't actually exist in FERC proceedings until Nov. 21, 2019, when the decision was authored. But FERC maintains that "rate changes required in [Federal Power Act] Section 206 proceedings should take effect as of the date of the order setting rates, not the date of the rehearing — regardless of whether and to what extent the rehearing order changes the rates originally allowed."

Glick said he would be "very interested" to see how the commission justifies its position before the courts to "rob consumers tens of millions of dollars in refunds in order to minimize the impact on transmission owners." ■

Wary of Contagion, MISO Bars Visitors for 2020

By Amanda Durish Cook

MISO will not open its doors to stakeholders or other visitors for at least the rest of the year as the coronavirus pandemic runs its course, the RTO said last week.

All remaining stakeholder meetings in 2020 will be held via teleconference, MISO Vice President of Strategy and Business Development Wayne Schug said during an Informational Forum on May 19.

The decision represents yet another — and more drastic — extension of MISO's COVID-19 response measures of holding virtual stakeholder meetings and restricting access to control rooms, policies the RTO last month had extended to June 1. (See *MISO Extends COVID-19 Measures*.)

MISO is also contemplating what timeline and safety precautions to follow before allowing select employees to physically return to its three office locations.

MISO CEO John Bear | © RTO Insider

"We're developing contingency plans," CEO John Bear said, adding that MISO is seeking stakeholder input on a staged reopening in 2021.

"We're looking to allow more staff to return to the office at least on a periodic basis. We're trying to balance work from home with our business interests and with our staff's personal needs," Schug said, noting that MISO expects some employees will have difficulty lining up childcare or have family members that are more susceptible to the disease.

Schug said MISO continues to work with epidemiologists to bring some employees back in a "safe and predictable manner." He also said it may consider holding some off-site in-person meetings later this year.

"Having said that, we understand the pandemic is a very dynamic situation," Shug said, adding that MISO would adjust dates and virtual meeting setups as necessary.

Schug said MISO will ask stakeholders during a June 17 Advisory Committee meeting for advice based on how their companies are navigating staged reopenings and deciding when to welcome visitors back into their offices. The AC meeting is part of the Board Week that was originally slated to take place June 16-18 in Milwaukee. Those meetings will now be spread out in virtual format over June 10-18 to keep the meeting schedule more manageable.

"Based on what we're hearing from you — and the world around us — our September meeting will likely be virtual, with a hope we can meet up in Orlando in December," Bear said.

MISO's quarterly Board Week in September was scheduled to be held in St. Paul, Minn.

MISO Executive Director Real-Time Operations Rob Benbow said no essential MISO control room personnel have tested positive for the virus to date.

"The control room staff have been doing a good job of isolating themselves … and maintaining that physical distance at work and at home," Benbow said.

Kevin Murray of the Coalition of MISO Transmission Customers asked how often the RTO orders virus testing and whether it has had difficulties securing tests for its employees.

Benbow said essential employees so far are only tested off-site if they experience symptoms. Operators are responsible for reporting any symptoms and isolating at home until they've been tested.

"We require them to have two negative tests before they return to work, so we've had about four to five operators go through this process," Benbow said.

In the meantime, Bear said MISO's virtual stakeholder meetings have been going smoothly.

"I think we're going to have some wonderful productivity and efficiencies out of this that can help reduce our costs," Bear said.

Schug said energy and demand in the footprint is currently trending down about 11% compared to usual spring consumption.

"We anticipate that as stay-at-home orders are lifted and things return to more normal patterns, those numbers will trend back up, but it's too hard to tell because those orders have just started to be lifted," Schug said.

MISO has reported that load has been about 10% below average because of the pandemic for about a month. Executives said that as some business reopen, they expect surges in load.

By April 6, 11 of the 15 MISO states were under a stay-at-home order. By the end of the month, three states ended their orders, with the remaining set to expire before the end of this month.

Benbow said MISO has been calculating what load would look like without the pandemic's effects to prepare itself for a return to more normal load.

However, April's below-normal temperatures and shelter-in-place directives *cut* peak load by 10 GW — to 73 GW —compared with the same period last year.

Real-time prices fell more sharply, with LMPs averaging $18/MWh compared with $26/MWh last April.

Benbow said natural gas prices in particular have been battered by the pandemic, with Chicago Citygate trading at an average $1.68/MMBtu, down from $2.46/MMBtu a year ago, and Henry Hub at $1.69/MMBtu, down from $2.59/MMBtu.

In the midst of the widespread quarantine measures, MISO set a new all-time wind generation peak of 18 GW on April 9.

Queue Waiver Request Before FERC

MISO has also requested a 60-day extension of its June 25 deadline for developers to demonstrate exclusive land use for projects entering MISO South's 2020 interconnection cycle. (See *MISO to File 1st COVID-19 Queue Waiver Request*.) The RTO asked for FERC to issue an order on the waiver by May 22 (*ER20-1794*).

Chris Supino, with MISO's legal department, said the waiver request doesn't foreclose individual waivers for interconnection customers.

"Obviously a customer is free to go to FERC and request any waiver they want," Supino said during a May 12 conference of the Interconnection Process Working Group. He urged customers to notify MISO of their situations to allow it to file supporting comments with FERC, should it deem a waiver necessary.

Supino said MISO will re-evaluate the need for further queue waivers if COVID-19 restrictions pick back up or continue for another month.

"It's easy to go overboard at first, and we're trying to take an incremental approach," Supino said. ■

MISO News

Michigan Dam with Longstanding Safety Issues Fails

By Amanda Durish Cook

About 10,000 central Michigan residents have been forced to evacuate their homes after a small hydroelectric dam beset by safety violations failed under heavy rainfall last week.

An earthen embankment at the 4.8-MW Edenville Dam in Midland County collapsed May 19, followed hours later by an *overrun* of the nearby Sanford Dam, flooding the surrounding area in up to 9 feet of water and prompting an emergency declaration by Gov. Gretchen Whitmer.

"If you have not evacuated the area, do so now and get somewhere safe," Whitmer *said*. "This is unlike anything we've seen in Midland County."

Michigan had previously rated Edenville in unsatisfactory condition, while Sandford received a fair rating. Both dams are about 95 years old and in the process of being sold.

FERC in 2018 revoked owner Boyce Hydro's hydropower license to operate Edenville, located between Wixom Lake and the Tittabawassee River, citing concerns about the dam not being able to handle floods.

Violations included failing to increase spillway capacity to address the increased likelihood of more frequent flooding; performing unauthorized dam repairs and excavation; neglecting to file a public safety plan or follow its own water monitoring plan; failing to acquire all property rights; and failing to construct required recreation facilities near the dam. The commission has spent about 15 years trying to get Boyce, which has owned the dam since 2004, to increase spillway capacity, the most serious of the safety violations.


Edenville Dam

Boyce has twice sought rehearing on FERC's decision to no avail. (See *Closed Michigan Dam Loses Rehearing Bid*.)

The Office of Energy Projects' Division of Dam Safety and Inspections "has determined that the failure of the project dam could result in the loss of human life and the destruction of property and infrastructure," FERC warned in 2018.

FERC also said Boyce's unexecuted plan to repair the spillways and use the temporary installation of a cofferdam for four to six months would "reduce the spillway capacity by approximately 50%, increasing the potential for overtopping of the dam." ■

MISO News

FERC: Refund Pledge from Nonpublic TOs Unneeded

By Amanda Durish Cook and Tom Kleckner

FERC last week reversed its earlier stance that would have required nonpublic utility transmission owners in MISO and SPP to explicitly commit to providing refunds.

The issue dates to 2012, after FERC concluded that it couldn't order refunds from Oklahoma's Tri-County Electric Cooperative even though its rates might have been inflated. The commission explained it approved SPP's filing of the co-op's annual transmission revenue requirement (ATRR) without a suspension or a voluntary refund commitment. Xcel Energy, acting on behalf of its Southwestern Public Service subsidiary, appealed the issue to the D.C. Circuit Court of Appeals in 2016.

The court *remanded* the issue back to the commission for action. FERC then opened an investigation into the RTOs' Tariffs over nonpublic utility TOs' revenue requirements that weren't accompanied by refund commitments. (See *FERC Backs off Nonpublic Utility Refunds in MISO, SPP*.)

But on Thursday, the commission acknowledged it would be an overreach of its authority if it required the refund commitments. It also said the move was unnecessary (*EL16-99*).

The commission noted that the D.C. Circuit in 2016 never ordered it to obtain refund commitments from nonpublic utility TOs in RTOs. FERC also said its authority to order refunds under the Federal Power Act only applies to jurisdictional public utilities.

"Although the commission has the authority to review nonpublic utility rates included in jurisdictional rates to ensure that the jurisdictional rate remains just and reasonable, it does not necessarily follow that a refund commitment from those nonpublic utilities is an intrinsic component of a just and reasonable rate. Generally, the commission does not treat refunds as a measure of a just and reasonable rate, but as an available remedy when a rate has been found unjust and unreasonable," FERC explained.

The commission said it can still approve voluntary refund commitments made by nonpublic utilities in ATRRs found in RTOs' jurisdictional rates.

The commission also said that by not mandating refund commitments, it could encourage RTO membership among nonpublic utilities.

MISO filed changes to its Transmission Owners Agreement and Tariff in 2018 requiring nonpublic utility transmission owners provide "all manner of refunds" that may be ordered under the FPA. FERC dismissed those compliance filings as moot in the order.

Commission Grants Rehearing in SPP Docket

In the SPP docket, FERC granted rehearing requests by several public power entities of its 2017 order, finding that it is "neither necessary nor appropriate" to impose the refund commitment on nonpublic utility TOs, as previously contemplated (*EL16-91*).

The commission also terminated its FPA Section 206 investigation of SPP and dismissed as moot the grid operator's compliance response to the 2017 order.

The Nebraska Public Power District, American Public Power Association, National Rural Electric Cooperative Association and Midwest Energy filed rehearing requests following the 2017 decision.

FERC found the D.C. Circuit's Xcel decision does not compel the commission to require a prospective refund commitment from all of SPP's nonpublic TOs. It said the court recognized that FERC "generally" does not have authority to require refunds if the entities do not voluntarily do so, and that its authority under the FPA applies only in limited circumstances. ■

| *Tri-County Electric Co-op*

NYISO Examines 'Evolution' to Zero Emissions

By Michael Kuser

NYISO will face myriad challenges in the coming decades as New York decarbonizes its economy and the power sector transitions to zero-emissions generation, industry stakeholders heard last week.

"Aggressive renewable goals raise questions about how a fully decarbonized energy system can work, especially given the intermittency of wind and solar," Sam Newell, a principal with The Brattle Group, told the Installed Capacity/Market Issues Working Group on May 18.

"Importantly, why we're here discussing this in New York is because New York has the mandates, and it's actually the first entire RTO to go to 100% clean," Newell said. "There are plenty of parts of the country where individual entities have already gone to 100%, but they're embedded in a much larger system that helps balance, so New York will be on the front end of seeing the challenges of going to a completely clean system."

Brattle representatives presented an interim *report* on New York's evolution to a zero-emission power system, modeling operations and investment in scenarios of increasing electrification for the years 2024, 2030 and 2040. They will consider feedback before presenting the final study results to stakeholders in June.

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

Electricity generation is already a relatively minor source of greenhouse gas emissions in New York, representing less than 16% of total emissions, so reaching economy-wide decarbonization goals likely implies significant electrification of buildings and transport, Newell said.

The high electrification case in the study sees 43 GW more capacity in New York by 2040.

Statewide Effort

NYISO is not alone in thinking about the future of the New York grid.

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

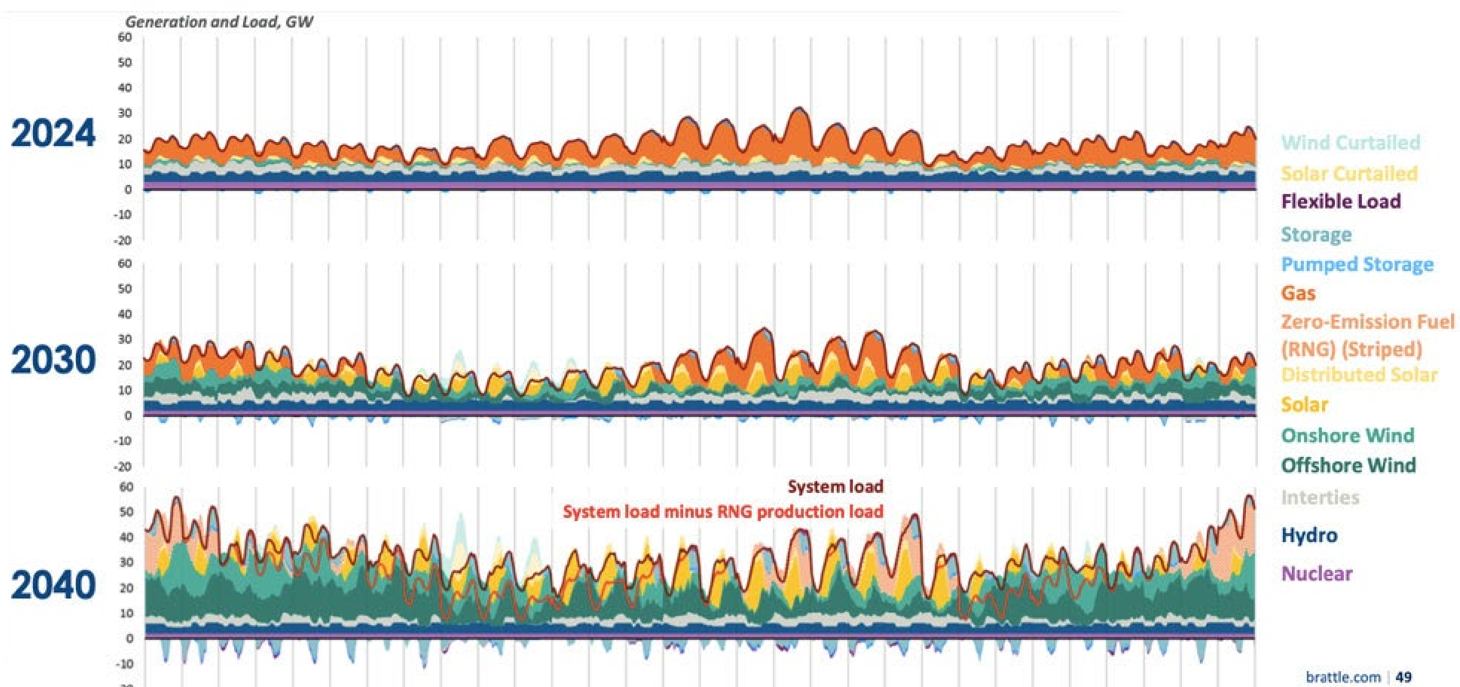
The study was mandated by a budget amendment passed in April that created a new siting agency for renewable energy projects. The New York State Energy Research and Development Authority will collaborate with the Department of Environmental Conservation and the Department of Public Service to develop build-ready sites for renewable energy projects. (See *NY Renewable Supporters Push for New Siting Agency*.)

"We're accounting, of course, for the Climate Leadership and Community Protection Act [CLCPA], but also other related programs and policies, such as continued participation in the Regional Greenhouse Gas Initiative, and the zero-emissions credit [ZEC] program for nuclear," Newell said. The ZEC program expires in March 2029.

New York's CLCPA (*A8429*), signed into law last July, mandates that 70% of the state's electricity come from renewable resources by 2030 and that generation be 100% carbon-free by 2040. (See *Cuomo Sets New York's Green Goals for 2020*.)

The law's clean energy mandates also include doubling distributed solar generation to 6 GW by 2025, deploying 3 GW of energy storage by 2030 and raising energy efficiency savings to 185 trillion BTU by 2025.

Newell said the NYISO study also accounts



Hourly generation and load: 2024, 2030 and 2040 | *The Brattle Group*

NYISO News

for the retirement of the Indian Point nuclear plant, as well as for "the new NO_x rules that are likely to cause about 3,000 MW of older peaker plants downstate to retire."

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

Balancing Challenge

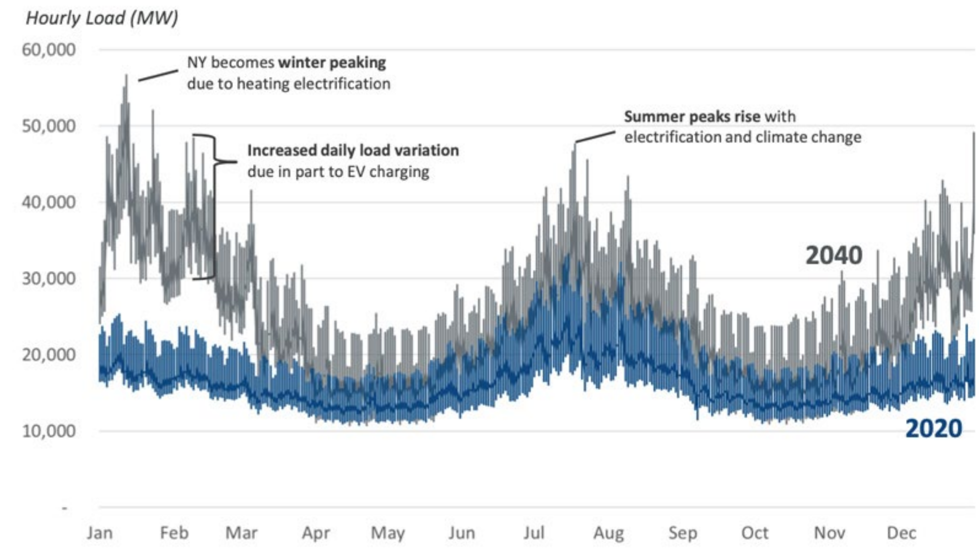
The paradigm shift coming to the electricity sector will see new technologies and resources supplant the old ways and means, the report said.

Today, gas-fired generators, dispatchable hydro and pumped hydro storage are key sources of flexibility, but the wind and solar output expected to dominate in the future is primarily driven by weather, thus reducing the amount of flexibility provided by generation.

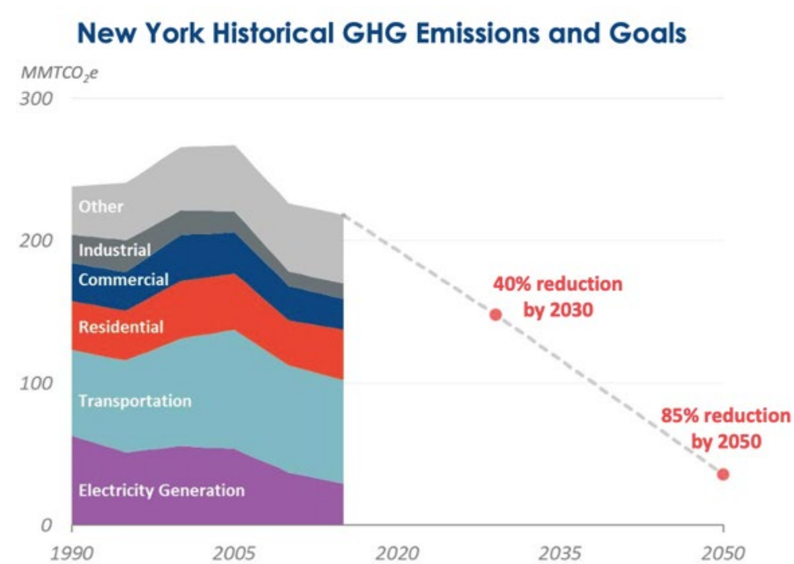
"Between 2030 and 2040, we also see significant growth in renewable generation, so by 2040, we're finding about two-thirds of load is served by wind and solar, and about one-third of load is served by offshore wind alone," said Brattle senior associate Roger Lueken.

The future system will require more flexibility across all timescales, with hourly and seasonal balancing of intermittent renewables and more volatile load, he said.

Flexible loads, such as controllable electric vehicles and HVAC, can provide limited balancing within the hourly time frame, but new technologies will be needed to provide seasonal storage or zero-emission, dispatchable supply.



Electrification and climate change will alter long-standing New York load patterns. | *The Brattle Group*



New York's economy-wide decarbonization trajectory | *The Brattle Group*

The balancing challenge is across multiple timescales, the report said.

"We find that throughout 2030 and even 2040 there's really minimal curtailment of wind and solar, despite the system predominantly being served by renewable generation, and that's due to the amount of short-term balancing from storage and from the long-duration balancing provided by renewable natural gas production and consumption," Lueken said.

Transmission Flows and Pricing

Today, New York transmission flows are primarily southbound, transferring power from upstate to downstate zones. In the future, those flow patterns become more variable, with flows occasionally reversing direction, the report said, noting that the frequency of constrained hours southbound generally increases.

Several stakeholders wanted more information on the transmission constraint and energy pricing assumptions in the study, but Newell deflected those questions.

"A model like this does produce shadow prices of all the constraints, which you could interpret. For example, if we have in 2030 a 70% clean requirement, you could interpret that as a market price for RECs [renewable energy credits]," Newell said.

"I think the New York ISO doesn't want to be in a position of putting out a study that implies a cost of the state policy objectives, particularly when we haven't focused in great detail with stakeholders on some of the cost constituents, like how much will the cost of various renewable resources come down, what might be the cost of an option with Hydro-Québec, or what might be some of the full resource integration costs," he said.

The value in studying the future grid is not the ability to predict very particular resource mix scenarios, but in providing illustrative outcomes of how the grid may evolve in order for planners to understand future attributes of the power system.

"What NYISO said to me, and I think said to you all in the beginning, is that this is to try to inform across a range of scenarios, what type of fleet does it look like?" Newell said. "Is it 100 GW of equal amounts of solar, wind and offshore wind? Just broad-brush, paint a picture so that we can even start to look at what reliability concerns there will be. Later we can discuss how you even begin to think about price formation." ■

NYISO Business Issues Committee Briefs

'Historically Low' Prices

NYISO is seeing "historically low" *load and prices*, Senior Vice President of Market Structures Rana Mukerji told the Business Issues Committee on Wednesday.

Day-ahead and real-time load-weighted locational-based marginal prices were $15.77/MWh in April, a drop from $17.11/MWh in March and $28.01/MWh a year earlier.

Year-to-date costs through April were $22.38/MWh, a 44% decrease from the same period in 2019.

Average daily sendout was 344 GWh/day in April, a drop from 375 GWh/day in March and 371 GWh/day in April 2019, Mukerji said.

60-minute Rule

The BIC voted to recommend that the Management Committee approve *changes* to section 4.4.3.1.1 of the Services Tariff to only award energy storage resources (ESRs) energy schedules that are sustainable for at least 60 minutes during a reserve pick-up (RPU) event.

The change was prompted by concern that during an RPU, real-time dispatch may award a larger energy schedule than an ESR can sustain for 60 minutes, as required by the Northeast Power Coordinating Council.

This can occur because the real-time dispatch/corrective action mode used to perform an RPU only looks out 10 minutes. (It needs to issue updated schedules very quickly.)

"This … could result in an ESR running out of energy and not being able to continue following basepoints during the critical 60-minute recovery period after loss of a resource or transmission element," said Aaron Markham, director of grid operations.

The ISO is proposing additional Tariff authority and updated RPU software to limit awards that are sustainable for 60 minutes (or more).

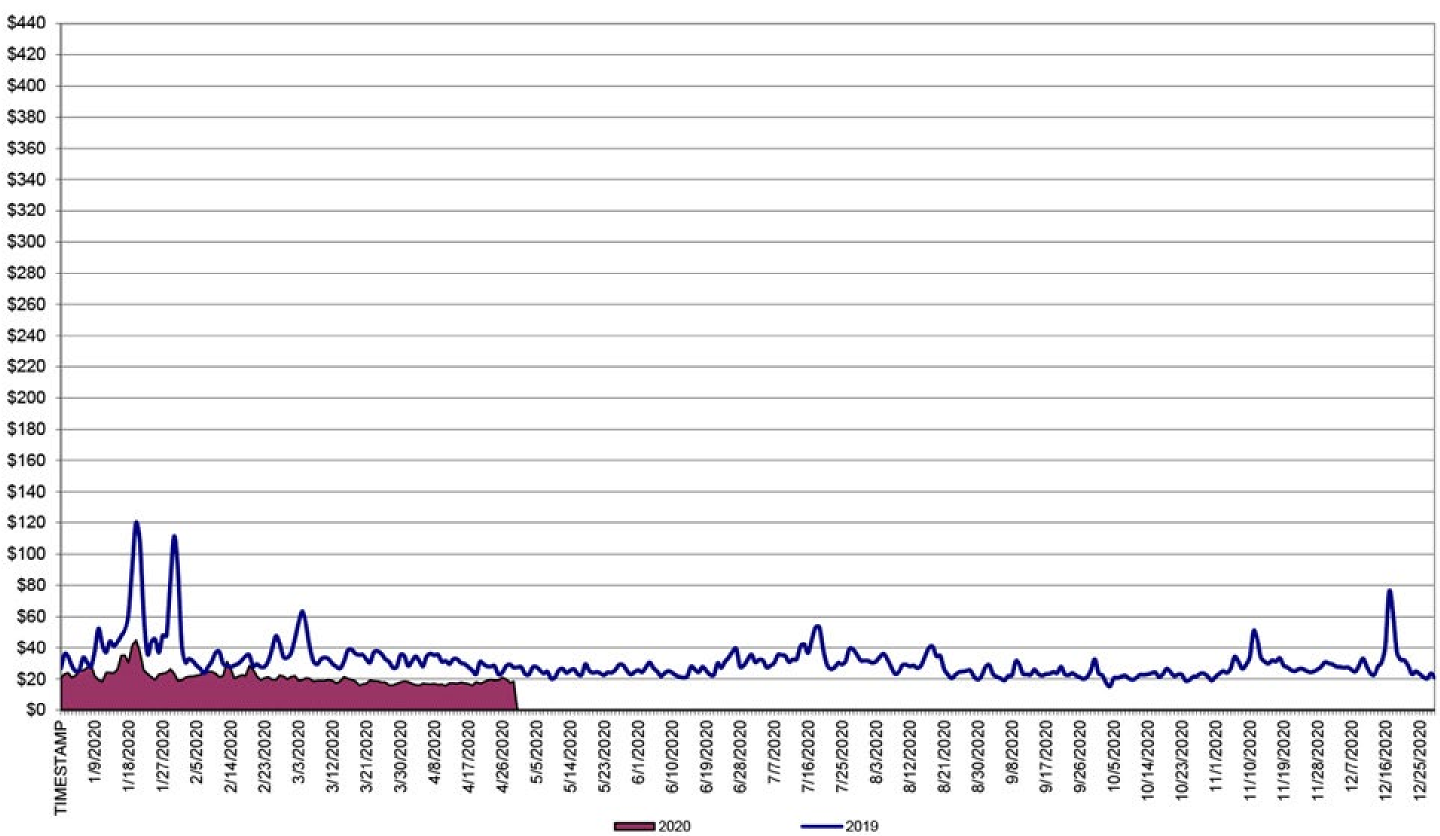
Peak Load Forecasts and Minimum Unforced Capacity Requirements for LSEs

The BIC voted to recommend that the Management Committee approve *revisions* to the NYISO Market Administration and Control Area Services Tariff sections 2, 5.10 and 5.11 to address a concern regarding the peak load forecast and minimum unforced capacity requirements for load-serving entities.

The forecast is determined using the prior calendar year's highest hourly actual load in the New York Control Area (NYCA), adjusted to "design conditions," which are expected to occur on a non-holiday weekday in July and August. About 80% of the highest coincident NYCA peak load hours have occurred in July and August.

The minimum capacity requirement is allocated among individual LSEs, determined by their consumption during the highest hourly actual load in the NYCA, regardless of whether that is consistent with consumption at "design conditions."

The ISO said it was concerned about situations in which the highest hourly actual load occurs outside the "design conditions" as in 2019, when the highest actual load occurred on a Saturday in July.



Daily NYISO average cost/MWh (energy & ancillary services, excluding ICAP payments) | *NYISO*

NYISO News

The proposed Tariff revision would require the use of the highest NYCA load hour occurring on a non-holiday weekday during July and August when calculating the NYCA peak load forecast. The change will ensure that each LSE's share of the minimum capacity requirement is consistent with the "design conditions" used to calculate the minimum capacity requirement.

If the highest load hour occurs on a weekend or holiday, load would be adjusted to account for expected additional load that would have occurred if the highest load hour had been a non-holiday weekday. Similarly, load also would be adjusted when the highest load hour occurs outside July and August.

If the temperature is higher than the design temperature, load will be removed to reflect the expected lower load that would have occurred if the highest load hour had taken place at the "design" temperature. The ISO said the change should ensure the incentive to reduce peak demand aligns with when the peak demand is expected to occur.

The changes will be presented to the Management Committee for approval on June 16, with board approval and a FERC filing expected in July. If it wins FERC approval, the changes would be effective for 2021/22 capability year.

Manual, Bylaw Changes

Members also approved changes to the following:

- Accounting & Billing Manual — *Changes* apply to ESRs, including provisions on settlements, day-ahead bid production cost guarantee and margin assurance payments. The changes will be effective at the same time as related ESR Tariff revisions.
- Revenue Metering Requirements Manual (RM2) — *Changes* apply to responsibility for meter inventory-related information; creation of metering configuration sub-sections for behind-the-meter net generation resources and ESRs; and allowable duration for the use of telemetry meter data as a back-up source for revenue meter data.
- Public Policy Transmission Planning Process Manual — *Updated* to reflect Tariff revisions to clarify, streamline and improve the Public Policy Process approved in 2019 (ER19-528). (See *NYISO Public Policy Tx Revisions Approved*.) Other revisions address cost-containment provisions approved in February 2020 for competitive transmission projects (ER20-617).
- BIC Bylaws — *Changes* to attendance rules, including a revision to allow nonmembers to attend by teleconference.
- Installed Capacity Manual — *Changes* to reflect FERC order Dec. 20, 2019, accepting most of the ISO's proposed Tariff revisions for compliance with Order 841 to accommodate and establish rules for participation of ESRs in ISO markets (*ER19-467*). (See *FERC Partially Accepts NYISO Storage Compliance*.) ■

— Rich Heidorn Jr.

FERC Approves PJM Reserve Market Overhaul

Glick Dissents, Says Ruling Will Cost Billions

By Michael Brooks

FERC on Thursday approved PJM's proposed energy price formation revisions, agreeing with the RTO that its reserve market was not functioning as intended (*EL19-58, ER19-1468*).

"PJM made a persuasive case that its current reserve market design must be overhauled," Chairman Neil Chatterjee said during the commission's monthly open meeting, held by teleconference because of the COVID-19 pandemic. "PJM showed that the current market mechanism systematically fails to enable PJM to acquire within the market the reserves it needs to operate its system reliably and [that] it fails to send appropriate price signals for efficient resource investment.

"The fact that PJM operators regularly must procure thousands of megawatts of reserves outside of the market construct is evidence of a market design that is unjust and unreasonable."

PJM filed its proposal unilaterally in March 2019 under Section 206 of the Federal Power Act because stakeholders could not come to a consensus on one plan. It was the culmination of a year's worth of debate and discussion among stakeholders, RTO staff and members of the Board of Managers. (See *PJM Files Energy Price Formation Plan*.)

The changes consolidate the tier 1 and tier 2 reserve products, align the products that PJM procures in the day-ahead and real-time markets and revise the height and shape of the operating reserve demand curve. "Together, these reforms will ensure that market forces, rather than out-of-market decisions, drive the procurement of reserves in PJM," Chatterjee said.

Commissioner Richard Glick issued a strong dissent, saying that "while I'm concerned that the commission made an unsupported finding that PJM's existing rate is unjust and unreasonable, I'm even more concerned and particularly troubled that the commission accepted PJM's proposal to revise the operating reserve demand curve. The commission is replacing marginal-cost pricing with an administrative adder that is going to force consumers to pay scarcity pricing all the time, regardless of whether there was actual scarcity or not. ...

"How is it 'market forces' when we're administratively drawing up a curve that makes no sense and the market wouldn't support? We're doing it, obviously, to raise prices," he said. "PJM and others continue to treat low prices — due in large part to a significant amount of excess generating capacity — as a matter that requires market tweaks designed to raise prices. Instead of addressing the true cause of the problem, which is excess capacity, this commission continues to approve proposals that raise prices. And what does that raise in prices do? It further exacerbates the problem."

The RTO had estimated in a December 2018 *white paper* that the changes would result in increased costs to load of about $700 million annually, but Glick said the costs could reach up to $2 billion.

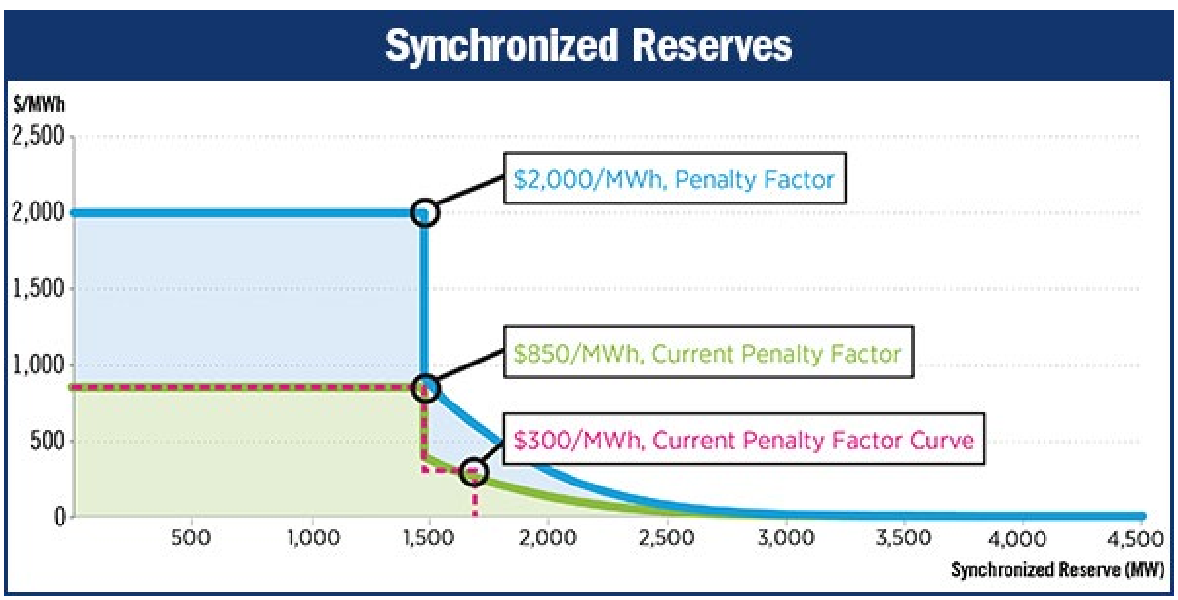
Chatterjee acknowledged that "these reforms will affect the amount of reserves procured and the energy and ancillary services revenues resources receive." To counterbalance the costs to consumers, the commission directed PJM to recognize the new changes in its capacity market's energy and ancillary services offset, a key variable in calculating the net cost of new entry for resources in the RTO's capacity auctions.

The offset is calculated using energy market results from the three calendar years prior to the Base Residual Auction. Therefore, "an historic energy and ancillary services offset would likely underestimate future energy and reserve market revenues, considering that PJM's proposal will likely result in increases in the energy and reserve prices compared to the historic values," the RTO said in the white paper.

Staff had proposed a mechanism that would have estimated the offset had the new rules been in place the previous three years, but the PJM board ultimately declined to include it in the filing. (See *PJM Advances Own Energy Price Formation Plan*.)

FERC ordered PJM to submit a compliance filing in 45 days to implement the mechanism.

"Recognizing the interplay between these reforms and the pending capacity market reforms," Chatterjee said, referring to the RTO's pending compliance filing implementing an extended minimum offer price rule, "we've asked PJM to propose an implementation schedule that harmonizes the reforms while minimizing auction delays." ■



PJM's new operating reserve demand curve (blue) as approved by FERC, compared to a previously proposed version (green) and old version (red dotted line) | *PJM*

PJM News

NJ Regulators Weigh Input on Capacity Market Exit

Continued from page 1

gions would choose more expensive resources within their jurisdictions rather than cheaper imports. (See related story, *Report: Imports Key to Successful FRR*.)

PJM also weighed in, *noting* that New Jersey is a capacity-importing state with more peak demand than unforced capacity within its service territories. If all capacity resources in New Jersey agreed to serve the state in an FRR, PJM said, the state would still require slightly more than 5,000 MW of additional capacity.

The RTO said it would not judge the cost of an FRR for New Jersey, but it urged regulators to closely examine claims that an FRR would lower costs.

"PJM does not comment with respect to the cost of an FRR for New Jersey," the filing said. "Instead, PJM cautions the BPU to look critically at any outright claims offered at this point in the proceeding that an FRR will prove less expensive for New Jersey consumers."

Supporters

Perhaps the strongest endorsement for the FRR option came in a joint *filing* by Public Service Enterprise Group and Exelon, whose state-subsidized nuclear generators would be subject to the expanded MOPR. They said the FRR would allow New Jersey "to exert greater control over how their load-serving entities meet resource adequacy requirements."

PSEG CEO Ralph Izzo said earlier this month it would be "logical" for the state to choose the FRR option. (See *PSEG Turns Bullish on NJ FRR Option*.)

The PSEG/Exelon filing said the FRR alternative could better support the clean generation goals in the state's 2019 *Energy Master Plan* (EMP) by integrating with other programs like the Regional Greenhouse Gas Initiative.

The filing also suggested integrating the procurement of capacity with the procurement of environmental attributes in the FRR "to standardize the state's support for clean electricity resources and encourage competition among different types of clean resources."

"Offshore wind projects qualifying for [renewable energy certificates], new grid-connected solar resources qualifying for state support, and the nuclear plants selected to receive ZECs would compete to sell their capacity and attributes, bundled together, for an all-in price fixed at the outset of a long-term contract, less forecasted energy revenues (based on futures prices for energy at a liquid trading hub) and ancillary services revenues determined in advance of each delivery year," the companies said.

"An integrated FRR procurement will allow New Jersey to fully and timely achieve its EMP goals at a lower cost for consumers than they would otherwise pay, by avoiding the inefficiencies that will result from FERC's new bidding rules in the PJM capacity auction," the filing said. "An integrated FRR procurement could also provide renewable developers with greater long-term certainty, reducing development costs."

Also coming out in support of an FRR was Ørsted, which was selected by the BPU last June to develop the state's first offshore wind project. (See *Orsted Wins Record Offshore Wind Bid in NJ*.)

Ørsted *said* current floor price estimates indicate its 1,100-MW Ocean Wind project, expected to be in service by 2024, will not clear future PJM capacity auctions and "may not be able to contribute to the state's capacity needs."

The FRR could provide a model for incorporating clean energy generation, the filing said, and the board should continue evaluating the impacts of other clean energy market mechanisms like carbon pricing.

"New Jersey should continue to be a national leader in clean energy development," the filing said. "Any mechanism pursued by the board should appropriately value clean energy resources for both their reliability and environmental benefits, minimize costs to ratepayers and encourage economic development."

The American Council on Renewable Energy *requested* that the BPU consider an "enhanced retail electric market" that could adequately procure resources aligned with the EMP's clean energy objectives through modifications to its Basic Generation Service (BGS) default procurement program. The BGS *auctions* are held by New Jersey's four distribution utilities to provide service to customers not served by a competitive retailer.

"New Jersey can ensure [that] enhanced retail electric markets are consistent with the EMP when coupling these reforms with a high-penetration renewable energy standard to directly drive deployment of carbon-free electricity and economy-wide carbon pricing to avoid carbon leakage," the filing said.

Detractors

Critics of the FRR appeared to outweigh supporters. Among those opposing the FRR were Calpine, the Independent Energy Producers of New Jersey, Natural Gas Supply Association, PJM Power Providers Group and the Retail Energy Supply Association.

The Electric Power Supply Association *encouraged* the BPU to "play a leading role" in developing regional solutions to meet environmental goals by working with PJM to consider adapting ISO-NE's Competitive Auctions for Sponsored Policy Resources (CASPR) market design. Under CASPR, ISO-NE will clear the Forward Capacity Auction after applying the MOPR to new capacity offers to prevent price suppression. In the second Substitution Auction, generators nearing retirement that cleared in the primary auction could transfer their obligations to subsidized new resources that did not clear because of the MOPR.

The New Jersey Division of Rate Counsel's *comments* focused on PJM's Independent Market Monitor study, citing the estimates that a statewide FRR could increase capacity costs for New Jersey ratepayers by 29% on the low end.

The Rate Counsel discouraged making changes to the BGS auction, saying it was created to "ensure a stable and affordable supply of energy for residential and small commercial customers who do not wish to or cannot shop for their electricity from third-party suppliers." It said the program has been a success in its current state by bringing customers the benefits of competition and a less volatile market.

The Rate Counsel urged the board to "proceed with caution" when considering the FRR because the option could bring "unwanted and expensive consequences," including lack of competition and market oversight.

"Our aims should be to foster competition, avoid enhancing market power and protect New Jersey ratepayers from excessive rates," the filing said. "While the FERC orders have certainly created roadblocks for the state to achieve its goals, we must make sure that our citizens continue to have safe, adequate and affordable service and that any action we take does not undermine that important, fundamental principle." ■

PJM News

New MOPR Analysis Sees Cost at $1B/Year

By Rich Heidorn Jr.

The expanded minimum offer price rule (MOPR) will cost PJM ratepayers almost $9.7 billion over the next nine years if FERC adopts revised floor prices allowing most nuclear plants to clear, according to a new *analysis* by critics of the commission's directive.

Michael Goggin and Rob Gramlich of Grid Strategies generated headlines last August with a report that predicted an expanded MOPR could add $5.7 billion annually to PJM's capacity costs. (See *MOPR Impact Study Ruffles Feathers Ahead of FERC Ruling*.) The estimate was cited by those calling for pulling the Commonwealth Edison zone in Northern Illinois out of the capacity market — and criticized by others, including Independent Market Monitor Joe Bowring, as wildly inflated.

Gramlich said the new analysis was prompted by FERC's December order, which exempted more existing renewable energy than prior proposals, and PJM's March 2020 compliance filing, which reduced MOPR floor prices for nuclear plants and renewables. (See *PJM MOPR Floor Prices Reduced for Gas, Nuclear, Solar Units*.)

The new analysis, released last week, considers two scenarios: one in which FERC accepts PJM's lower floor prices, and one in which the prices reflect the RTO's original October 2018 proposal.

The authors say the new report is subject to many uncertainties, but that even under the best-case scenario, the MOPR is guaranteed to raise prices. "There are so many versions of MOPR and factors such as bid levels that vary between versions and over time that it is not possible to definitively conclude, as some have, that MOPR will have limited cost impacts," the report says. "Under most scenarios, MOPR will result in billions or tens of billions of dollars in excess costs to electricity consumers across PJM."

The report notes that the clearing price for the most recent Base Residual Auction in 2018 was $140/MW-day, with some zones clearing at between $165.73 and $204.29/MW-day.

PJM reduced MOPR floor levels of $175/MW-day for solar PV with tracking, which would have been low enough to clear in some areas of the RTO in 2018. But the RTO's proposed $367/MW-day for solar PV without tracking, $1,023/MW-day for land-based wind and $3,146/MW-day for offshore wind are well above prior clearing prices.

PJM's new proposal would allow multiunit nuclear resources to clear the market along with most or all single-unit nuclear plants. The authors assumed new renewable sources would not clear under either of the two scenarios, regardless of whether they were using the default bid levels proposed by PJM or resource-specific offer floors.

"It is likely that some solar, and potentially some land-based wind projects, could demonstrate evidence for unit-specific bid levels that are low enough to clear the capacity market," the report acknowledged. "If resources do not clear, capacity market prices increase and redundant replacement capacity must be purchased and paid for by consumers, further increasing their bills."

Under the first scenario, the new MOPR could increase capacity costs by nearly $10 billion total over its first nine years, an average of more than over $1 billion annually. PJM's capacity costs last year totaled $8.7 billion.

Under the second scenario, subsidized nuclear units in Illinois, New Jersey and Ohio would fail to clear, resulting in an increase of almost $24 billion over the nine years, an average of $2.6 billion annually, the authors say.

Projected increase in capacity costs by region and delivery year ($ millions) | *Grid Strategies*

Caveats

The authors said their estimates are likely conservative because they don't include the impact of subjecting self-supply, state default service auctions, demand response and energy efficiency resources to the MOPR.

Another variable is how quickly PJM states meet their renewable portfolio standards. Grid Strategies estimates almost 47 GW of nameplate capacity wind, solar and storage will be needed by 2030 to meet state targets.

"The cost of MOPR would be higher if renewable deployment is front-loaded into the next few years to benefit from federal renewable tax credits that are phasing down for projects completed through the mid-2020s" as was assumed in the 2019 study, the authors said. "This would result in a larger cost being attributable to MOPR, as those resources are subject to MOPR for a longer period of time and there is a larger price impact in the near term, but likely lower total cost to consumers because the renewable projects benefits from larger tax credits."

Another course of uncertainty is that PJM is planning to revise the method for calculating the capacity value of wind and solar projects. (See *PJM MRC Moves Forward on Storage, Hybrids*.) ■

PJM News

Report: Imports Key to Successful FRR

IMM Studies Criticized

By Rich Heidorn Jr.

A new study finds that analyses by PJM's Independent Market Monitor predicting increased costs for regions that exit PJM's capacity market are skewed by their assumptions and should be redone to presume exiting states will maximize imports to counter local market power.

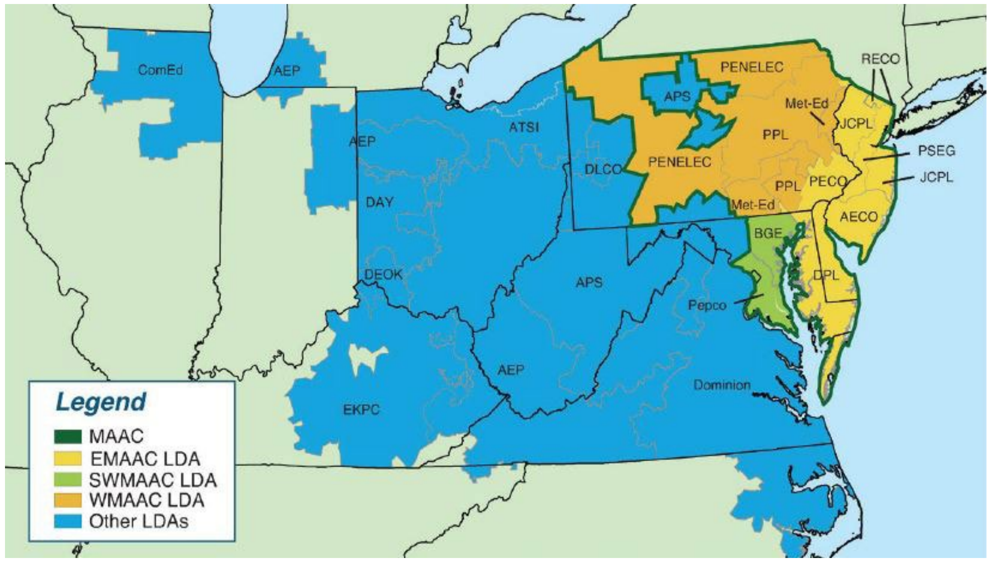
"The reports' cost estimates risk confusing or even misleading states to the extent they suggest confidence that FRR [fixed resource requirement capacity procurements] will yield higher prices than continued reliance on PJM's RPM [Reliability Pricing Model]," said the report by Rob Gramlich, president of Grid Strategies, and consultant Miles Farmer, a former attorney for the Natural Resources Defense Council.

"At this stage, given uncertain market dynamics and questions surrounding how states and utilities may implement FRR, it is difficult for anyone to render a confident and accurate prediction of FRR prices. While Monitoring Analytics provides useful data and a structure to evaluate FRR costs, we recommend that it provide a more complete picture of the potential costs of FRR by conducting additional scenarios applying the reasonable assumption that FRR entities would competitively procure externally located capacity."

Gramlich and Farmer released their study Wednesday, the New Jersey Board of Public Utilities' deadline for comments in its docket on the state's options for ensuring resource adequacy. (See related story, *NJ Regulators Weighing Input on Capacity Market Exit*.) The report expanded on the critique Gramlich has made in recent forums with Joe Bowring, president of Monitoring Analytics. (See *PJM Monitor Defends FRR Analyses in MOPR Debate* and *Moving Forward on MOPR*.)

The Monitor said its analyses in Illinois, Maryland and New Jersey indicate ratepayers are likely to see costs increase if their jurisdictions leave the PJM capacity market for an FRR. The reports also concluded that the expanded minimum offer price rule (MOPR) is unlikely to increase capacity costs, at least for the first couple of auctions. (See *PJM Monitor Finds Capacity Exit Costly for NJ*.)

The Gramlich-Farmer report did not attempt to quantify the impact of an FRR, but it said "a reasonable set of assumptions yields lower price estimates for FRR than for continued reliance on RPM."



State officials in Illinois, Maryland and New Jersey are considering alternatives to the PJM capacity market. | *Monitoring Analytics*

The authors said any analysis should assume that an FRR service area located partially or fully within a constrained locational deliverability area (LDA) would seek to purchase as much capacity as possible at lower prices outside the LDA before "meeting the rest of internal load with internal generation."

They said states should request that the Monitor provide them data on the maximum import capability into constrained zones, which will determine the minimum internal resource requirements.

"Monitoring Analytics reports all suffer from a central flaw: They assume that FRR entities would purchase as much capacity as possible from internal resources, importing capacity only to the extent 'needed to cover any shortfall in meeting the FRR obligation,' even where the FRR entity is located within a transmission-constrained area where local capacity prices are higher than those of the importing region(s)," the report said. "Monitoring Analytics never justifies this assumption, which leads to higher prices across all scenarios that modeled an FRR entity located entirely or partially within a transmission-constrained LDA.

"While this framing suggests an apples-to-apples cost comparison, in fact it yields skewed results that in effect presume an irrational capacity purchasing strategy by the FRR entity."

Bowring continued to stand behind his analyses Thursday, saying, "It is extremely unlikely that the FRR approach will result in prices equal to or lower than market prices."

He criticized the Gramlich-Farmer report's references to the resource adequacy policies of MISO and CAISO, saying neither are markets. "MISO relies on cost-of-service regulation with its attendant high costs and lack of competition, and CAISO relies on an inefficient process of bilateral contracting for capacity."

The report noted that the Monitor found a 5.4% reduction for an FRR in Maryland's PEPCO LDA — which is not constrained by a binding transmission import limit — under a scenario in which capacity prices would be equal to the most recent Base Residual Auction.

Gramlich and Farmer also questioned why half of the Monitor's scenarios assumes all suppliers — not just pivotal suppliers that possess market power — will be paid prices at the seller offer cap.

"Market power is a significant challenge that states, PJM and FERC should carefully address in designing and implementing FRR. But it is important to recognize that FRR does not 'create' market power, which flows from the underlying dynamics of market suppliers' gen-

PJM News

eration ownership and relevant transmission system constraints," they said.

They also disagreed with the Monitor's conclusion that the expanded MOPR will not increase costs in upcoming BRAs. Gramlich last week released another study projecting that the expanded MOPR will cost ratepayers $9.7 billion or more over the next nine years. (See related story, *New MOPR Analysis Sees Cost at $1B/Year*.)

"MOPR will raise RPM costs to the extent it raises market clearing prices by causing higher priced supply offers and to the extent it forces customers to support the construction or retention of redundant capacity. MOPR also could increase the cost of state programs because state-supported resources that do not clear the capacity market may require more revenue from renewable energy credits (RECs) and other payments in order to cover their costs and be developed as the states desire."

In contrast, Gramlich and Farmer said, FRR programs could procure capacity from state-supported resources at prices that reflect state subsidies. "The costs of state clean energy policies would also be reduced as compared to BRA with MOPR because state-supported resources could more confidently rely on capacity revenues."

The authors said lower costs are likely under FRR because it would require only a 15% reserve margin — using a vertical demand curve and fixed megawatt requirement — rather than the 22% margin in recent RPM auctions, which uses a sloped demand curve. They cited an *estimate* from ICF that the lower reserve margin under FRR could reduce prices by $15 to $25/MW-day in the near term and $30 to $50/MW-day in the long term.

The study also said FRR would give utilities and states more flexibility because nonperformance penalties could be assessed on a physical and portfolio-wide basis rather than as an economic penalty applied to individual units under RPM. They said unit-specific financial penalties have been a disincentive to renewables' participation in the capacity market.

Bowring questioned why Gramlich and Farmer assert "that the weaker performance incentives in an FRR would be a good thing. An essential point of the Capacity Performance design was to strengthen performance incentives. One of the strengths of well-designed markets is that investors bear the risks associated with the performance of their assets," he said.

FRRs could make better use of seasonal resources than RPM, they said, citing a Brattle Group *report* that concluded separating summer and winter capacity markets in PJM would save consumers $100 million to $600 million annually.

FRRs also could obtain lower prices by giving sellers multiyear price locks. "Price formulas could partially or fully index to RPM. And the purchase could also be combined with energy, ancillary services or environmental attributes providing the purchaser and seller more certainty as to their total costs and revenues."

The authors acknowledged that PJM rules bar utilities from returning to the capacity auction for at least five years after departing (though PJM allows an exception if state regulatory changes materially affect consumers' retail choice options).

They also noted concerns that state regulators would have to prevent distribution companies from acting on incentives to favor their own generation under an FRR.

Under PJM rules, the entity responsible for obtaining capacity could be a utility, distribution company or state agency. Legislation pending in Illinois would give such responsibility to the Illinois Power Agency. (See *Clock Ticking on Exelon Illinois Nukes Under MOPR*.) ■

PJM News

Strah Named New President of FirstEnergy

Jones Remains as CEO

From left, Steven E. Strah, Charles E. Jones, K. Jon Taylor, Robert P. Reffner and Ebony L. Yeboah-Amankwah | *FirstEnergy*

By Michael Yoder

FirstEnergy promoted its chief financial officer on May 19 to take over as president beginning this week.

Steven E. Strah, who was named CFO and senior vice president in 2018, was elected by the FirstEnergy board of directors to serve as president effective Sunday. Strah is taking over the role as president from Charles E. Jones, who has been FirstEnergy's president, chief executive officer and member of the board since 2015. Jones will continue to serve as CEO and a member of the board.

Strah will oversee FirstEnergy Utilities; corporate services and information technology; finance; product development, marketing and branding; external affairs; rates and regulatory affairs; and strategy. Strah, who began his career with The Illuminating Company in 1984, previously served as regional president and vice president of distribution support of Ohio Edison, and senior vice president at FirstEnergy Utilities.

"Steve is a strategic and driven leader with a deep understanding of FirstEnergy's business and the needs of our customers, employees and investors," Jones said in a *press release*. "He is committed to driving our long-term, customer-focused growth plans, as well as our mission to be a forward-thinking electric utility."

FirstEnergy also made several other senior leadership moves last week:

- K. Jon Taylor was elected senior vice president and CFO and will report to Strah, overseeing accounting, treasury and investor relations.
- Robert P. Reffner was elected senior vice president and chief legal officer, reporting to Jones. He will add risk management and internal auditing to his current duties overseeing the corporate, legal, information and compliance and real estate departments.
- Ebony L. Yeboah-Amankwah was elected vice president, general counsel and chief ethics officer, reporting to Reffner.
- Mary M. Swann was elected corporate secretary, reporting to Yeboah-Amankwah.
- John Skory was named vice president of FirstEnergy's utility operations.
- Gary W. Grant Jr. becomes president of Ohio operations, reporting to Skory.
- Michelle R. Henry, director of FERC and state regulatory compliance since 2018, was named vice president of customer service.
- James H. Myers III was named president of West Virginia operations. Myers is taking over for Holly C. Kauffman, who is retiring after 36 years with the company. ■

PJM News

FERC Rejects Complaints on PJM Seasonal Resources

Glick: Year-round Resources not Cost-effective

By Rich Heidorn Jr.

FERC last week rejected requests to change PJM's capacity market rules to accommodate seasonal resources, saying the complainants failed to prove current market rules are unjust and unreasonable (*EL17-32, EL17-36*).

The order was prompted by a December 2016 complaint by Old Dominion Electric Cooperative (ODEC), Direct Energy Business and American Municipal Power and a January 2017 filing by Advanced Energy Management Alliance (AEMA) over the procurement of capacity in PJM's Reliability Pricing Model.

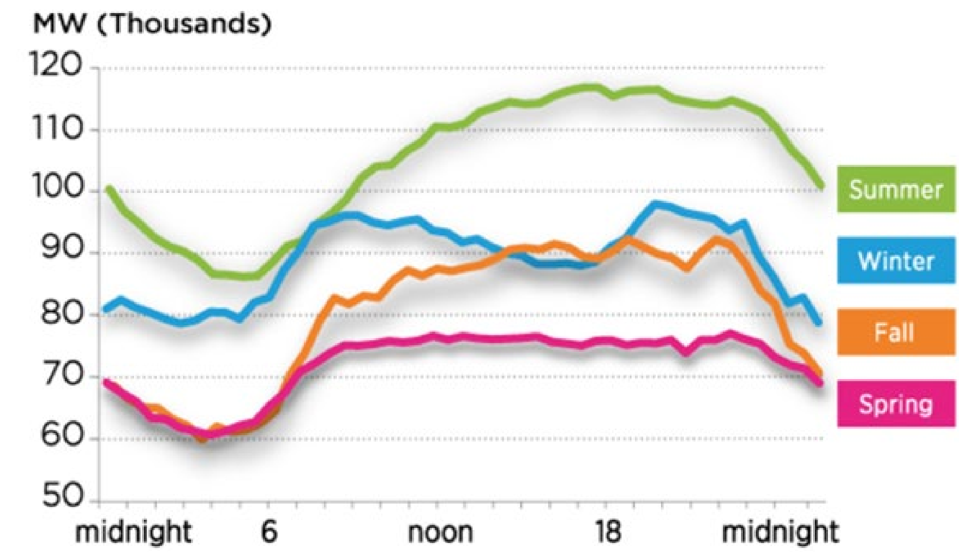
ODEC asked the commission to establish a proceeding to allow seasonal resources to participate in capacity auctions. AEMA said PJM's move to 100% Capacity Performance resources was unnecessarily costly for ratepayers, citing studies that it said proved that all of PJM's resource adequacy risk is in the summer.

PJM adopted the CP rules — which increased bonuses for overperformance and penalties for underperformance — in response to the 2014 polar vortex, when the RTO came close to shedding load with as much as 22% of its generating fleet on forced outages.

"The core of the complaints is that because PJM is a summer-peaking system, PJM could acquire more summer capacity than winter capacity at an economic savings without sacrificing system reliability," the commission said. The complainants pointed to PJM data that they said showed that by increasing summer requirements by about 500 MW, the RTO could replace more than 17,000 MW of annual capacity with less expensive summer resources without jeopardizing reliability.

Reasonable Accommodation

The commission ruled in 2015 that using the same capacity requirement for winter and summer was justified by deteriorating resource performance and the change in the RTO's resource mix. Allowing non-year-round resources to continue participating in the capacity market could lead to reliability problems in non-summer months when seasonal resources are unavailable, it said. The commission said PJM had provided a reasonable accommodation by allowing storage resources, intermittent generators, demand response and energy efficiency to submit aggregated offers.



PJM's summer peaks can top 150 GW, while the winter typically peaks at less than 100 GW. | *PJM*

The commission's approval of CP was backed by the D.C. Circuit Court of Appeals, which ruled that the "law provides no basis to claim the commission cannot approve uniform performance requirements simply because those requirements will be easier to satisfy for some generators than others."

In response to the commission and D.C. Circuit rulings, the complainants provided planning studies and other evidence that they said proved that PJM could meet its resource adequacy targets more cost-effectively by tailoring its procurements to recognize seasonal variation. Summer peaks can top 150 GW, while the winter typically peaks at less than 100 GW.

Although the commission held a *technical conference* in April 2018 to explore the issues raised by the complaints, it said there was insufficient evidence to overturn the CP rules.

Data Limitations

FERC cited PJM's warning that "modeling assumptions underlying the data on which complainants rely … warrant caution in interpreting the meaning of that data."

While the RTO's annual installed reserve margin study indicates that only a small amount of loss-of-load-expectation risk occurs in the winter, "recent operating experience suggests that such risk may in fact be higher," FERC said.

PJM also said AEMA's contention that an additional unit of summer-only capacity has 97% of the reliability value of an additional unit of year-round capacity was based on an incorrect premise that changing to seasonal capacity resources would not also change other modeling assumptions underlying the data.

"In light of these identified limitations in the data presented, we are not persuaded that the evidence complainants present is sufficient to show that the Capacity Performance model is no longer just and reasonable," the commission said. "Ultimately, we are not convinced that it is necessary for PJM to abandon its single-product Capacity Performance model based upon the limited experience since the commission's approval. As PJM argues, it deserves the opportunity to gain more experience with implementation of Capacity Performance and its rules over time to determine whether it provides performance and reliability during all seasons of the year."

Glick Concurrence

Although the ruling was unanimous, Commissioner Richard Glick wrote a concurrence saying that "a seasonal capacity construct appears to be a more just and reasonable approach than PJM's current one-size-fits-all" rules.

Glick said that while he agreed the complainants had not proved that the CP rules are unjust and unreasonable, "the record does, however, hint at a number of more fundamen-

PJM News

tal problems with PJM's capacity construct [that] merit a comprehensive review in PJM's stakeholder process and, if necessary, by this commission."

He said the evidence "underscores the difference between the reliability challenges in the summer and winter and … suggests that moving away from a uniform annual product could allow more resources to provide capacity, thereby increasing competition and promoting more efficient pricing."

"Although the high reserve margins that help manage the summer-time peaks may also address winter concerns, they are not the most direct way to do so," he continued. "The fact that having extra resources on the system may help manage non-peak reliability challenges does not necessarily justify PJM's current approach or excuse it from pursuing means of addressing those challenges more directly and cost-effectively."

Glick also pointed to the "unintended consequences" of PJM's excess capacity.

"PJM, its stakeholders and this commission have devoted considerable time and resources to promoting proper price formation in PJM's energy and ancillary service markets. Over-procuring capacity tends to dull those price signals, reducing, or altogether eliminating, many of the benefits of those price formation efforts."

He also said he was troubled by "the implication of PJM's statement that adopting a seasonal market could cause 'premature resource retirement.'"

"PJM's goal cannot be the protection of 'conventional' resources, nor should it spend its time fretting over the effects that a more efficient market design may have on the resource mix," Glick said. "Instead, PJM should be focused on identifying the services the grid needs to remain reliable and structuring its markets to procure those services in the most efficient, technology-neutral manner possible. In any case, it is hardly 'premature' for a resource to retire because some other resource can more efficiently meet the needs of the market. That type of competition should be the goal of the capacity market, not a problem to be avoided."

Glick also said excess capacity also has undermined the "underpinnings of PJM's Capacity Performance proposal, which envisioned many penalty hours per year."

"The commission's recent decisions regarding PJM's variable resource requirement curve and minimum offer price rule (MOPR) will only exacerbate that capacity glut, further reducing the chances of a Capacity Performance penalty. ...

"Capacity Performance events will be even less likely after the issuance of today's order on the operating reserve demand curve, which will result in PJM carrying reserves far in excess of its reserve requirement, further reducing the likelihood of a Capacity Performance event." (See related story, *FERC Approves PJM Reserve Market Overhaul*.)

"If there is little-to-no prospect of a capacity shortfall, then it would seem correspondingly harder to justify the qualification restrictions, including the limitations on seasonal resources. I recognize that some of the capacity glut is the result of the commission's actions, not PJM's, and that this share may continue to grow as the consequences of the commission's MOPR ruling play out. But that should not stop PJM from taking a hard look at whether Capacity Performance remains appropriate under current market conditions and, in particular, whether the barriers it created for seasonal resources should be removed." ■

PJM Ordered to Revise Pseudo-tie Rules

By Rich Heidorn Jr.

PJM's rules for pseudo-tied resources lack "sufficient notice and transparency" regarding how the RTO conducts its market-to-market (M2M) flowgate test and applies its electrical distance requirement, FERC ruled last week.

Acting on complaints by Brookfield Energy Marketing and Cube Yadkin Generation, the commission ordered PJM to amend its Tariff within 45 days to address the shortcomings.

Brookfield contended that PJM's deliverability requirements and M2M flowgate test were interfering with the ability of the company's Calderwood and Cheoah hydroelectric generation facilities in the Tennessee Valley Authority and Duke Energy balancing authority areas to provide capacity in the RTO. The commission ruled that Brookfield had not proven that PJM's pseudo-tie requirements are unjust and unreasonable (*EL19-34*).

The commission also rejected Cube's allegation that PJM applied the electrical distance requirement in an unjust and unreasonable manner to the company's four hydroelectric resources. But the commission required the RTO to amend its Tariff to spell out the procedure in more detail (*EL19-51*). The Tariff defines "electrical distance" as "the measure of distance, based on impedance and in accordance with the PJM manuals, from the generation capacity resource to the PJM region."

FERC ordered PJM to revise its Tariff to provide pseudo-tie applicants with results of their tests and related work papers and to post on its website the assumptions used in the tests. It also required the RTO to meet with applicants if requested to discuss assumptions, modeling and test results.

In a third order, FERC rejected a complaint by Tilton Energy alleging that PJM wrongly determined that Tilton's pseudo-tie from the MISO BAA into PJM did not pass the M2M flowgate test (*EL18-145*).

The company filed a complaint after its 176-MW natural gas-fired generation facility in the MISO BAA was rejected by PJM because 44 of the tested flowgates failed the test. PJM uses the test to determine whether it can use a dispatchable internal resource to alleviate the impact on congestion caused by the external pseudo-tied resource.

The failed test prevented Tilton from participating in capacity auctions after the 2021/22 delivery year, despite having served as a capacity resource in two prior years.

The commission sided with PJM's interpretation of its Tariff regarding the testing. "We find that PJM's interpretation reasonably permits PJM to reject pseudo-ties that could create new coordination and congestion costs," it said.

It said the fact that Tilton had previously been accepted as a capacity resource was irrelevant. "Tilton has not previously been subject to the flowgate test, given the five-year transition period for existing pseudo-tied resources," it said. ■

FERC OKs Most of PJM Order 845 Compliance Filing

Requires Filing on 'Surplus' Interconnection Refunds

By Michael Yoder

FERC on Thursday largely accepted PJM's Order 845 compliance filing addressing concerns over a lack of transparency regarding contingent facilities (*ER19-1958*).

Contingent facilities are unbuilt interconnection facilities and network upgrades upon which an interconnection request's costs and timing are dependent.

In December, FERC *approved* six of PJM's 10 Order 845 proposals, requiring changes on four issues. A Feb. 21 *filing* by the RTO sought to address the commission's concerns by clarifying the scope of the study and the criteria used and also clarified that studies for provisional interconnection service will be conducted annually.

Thursday's order accepted PJM's filing on three of the four issues that required changes, including: revisions regarding contingent facilities; provisional interconnection service that allows limited operation of a generating facility prior to completion of the full interconnection process; and rules governing technology changes that can be considered without affecting the interconnection customer's queue position. All three revisions are to go into effect July 20.

FERC's December order also required PJM to conduct the surplus interconnection service process outside of the interconnection queue. Surplus service is any unused portion of interconnection service established in a large generator interconnection agreement.

PJM's revisions required that surplus service be only from in-service generators and that use of the service cannot impact the existing system or other queue projects as determined by load flow or short-circuit and stability analyses. Applicants will be required to make a study deposit of $10,000 plus $100/MW, not to exceed $110,000.

The American Wind Energy Association, Solar Energy Industries Association and the Solar Council, filing jointly, *challenged* PJM's revisions on the surplus interconnection study, saying that they did not specify whether a surplus interconnection customer will receive a refund for the unused portion of its deposit if an application is rejected or withdrawn.

FERC agreed with the groups' comment,

Site of a proposed Ohio wind farm and solar project brought to PJM by Leeward Renewable Energy in 2017. Leeward cited the project in a FERC filing against PJM. | *PJM*

writing that PJM needed to add language to provide for refunds. It directed PJM to submit a compliance filing within 120 days and make the surplus interconnection service effective Nov. 17.

"We find PJM's proposed effective date reasonable, given the software and manual changes PJM needs to make before implementing these compliance requirements," FERC wrote.

Rehearing Denied

FERC also rejected a rehearing *request* filed Jan. 21 by Leeward Renewable Energy challenging its December order. Leeward argued that FERC had failed to address whether PJM can reject an interconnection customer's "technological advancement request" as constituting a material modification without any review or analysis.

Leeward cited a proposed Ohio wind project that it wanted to convert to a solar project in response to state legislation that nearly tripled the minimum property line setback for wind turbines. Leeward said PJM judged the change a material modification — forcing the developer to relinquish its queue position and file a new interconnection request without reviewing studies, which the company said is contrary to Order 845 and the RTO's Tariff.

PJM said the commission in Order 845 stated that "a change between wind and solar technologies involves a change in the electrical characteristics of an interconnection request."

Leeward responded that although Order 845 found that a change between wind and solar technologies cannot automatically be considered a permissible technological advancement, such a change should not be automatically considered a material modification and that transmission providers should be required to evaluate such changes.

In denying rehearing, the commission said that interconnection customers seeking to enter the technological change procedure must demonstrate that the proposed change results in "equal to or better" electrical performance. "Should it fail to do so, such a proposed change should proceed through the material modification procedures," FERC said.

The commission said PJM's February compliance filing proposed a new procedure for responding to requests to modify interconnection request to include a technological advancement.

"In light of our discussion above, accepting PJM's new Tariff section 36.2A.2.2 and reminding PJM of its obligation to provide an explanation if it cannot accommodate a proposed technological advancement without triggering the material modification provisions, we find that Leeward's concerns regarding technological advancement requests raised on rehearing have been addressed and, thus, are moot," FERC said. ■

PJM News

PJM MRC/MC Preview

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

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

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

Members will be asked to endorse the following manual changes:

B. *Manual 01: Control Center and Data Exchange*. Periodic review, including revisions to Attachment A: Data Specification and Collection and Attachment B: Schedule of Data Submittals.

C. *Manual 03: Transmission Operations*. The manual will be split into a public version, including sections 1-4 and attachments and a secured Manual 03B on transmission operating procedures containing critical energy/electricity infrastructure information.

D. *Manual 03: Transmission Operations*. Biannual review to update operating procedures.

E. *Manual 18: PJM Capacity Market*. Revisions to conform with FERC orders on price-responsive demand (ER20-271).

F. *Manual 36: System Restoration*. Annual update includes revisions to Attachment B: Restoration Forms and Attachment G: Coordination of Restoration Plan with PJM Internal and External Neighboring Entities - PJM Approval Process for TO Restoration Plans.

Endorsements/Approvals (9:10-11:30)

1. Surety Bonds (9:10-9:35)

Members will be asked to endorse a *proposal* to allow market participants to use surety bonds as collateral in addition to letters of credit, which can be more expensive. (See "Surety Bonds," *PJM MRC Briefs: April 30, 2020*.)

2. PMA Credit Requirements (9:35-9:50)

Members will vote on a "quick fix" Tariff *revision* to address a regulatory change in Ohio concerning the billing of network integration transmission service (NITS). PJM requires load-serving entities to sign NITS agreements and post collateral based on their peak market activity. (See "'Quick Fix' for NITS Rule," *PJM MIC Briefs: May 13, 2020*.)

3. Integration of HVDC Converter Problem Statement (9:50-10:10)

Members will be asked to approve an *issue charge* to investigate the integration of HVDC converters as a new type of capacity resource. The initiative is being *proposed* by Direct Connect Development Co., which is planning the SOO Green HVDC Link, a 350-mile, 2,100-MW, 525-kV underground HVDC transmission line to deliver Iowa wind power to Illinois.

4. Transparency and End-of-life Planning (10:10-11:10)

The committee will be asked to choose between transmission planning changes proposed by multiple *stakeholders* and favored by load interests, and a PJM *proposal* backed by transmission owners. The proposals could open end-of-life transmission projects to competition and regional planning. (See related story, *TOs: PJM 'At a Crossroads' on Eve of EOL Vote*.)

5. Capacity Capability Senior Task Force Issue Charge (11:10-11:20)

Members will be asked to vote on revisions to the Capacity Capability Senior Task Force *issue charge* on effective load-carrying capability for limited-duration resources and intermittent resources. The change will incorporate revisions in response to FERC's April 10 order granting PJM's motion to hold a paper hearing on the capability of energy storage resources in abeyance to allow stakeholder negotiations (ER20-584 and EL19-100). (See *PJM MRC Moves Forward on Storage, Hybrids*.)

6. Fuel Requirements for Black Start Resources Issue Charge (11:20-11:30)

Members will be asked to endorse a revised *issue charge* on fuel requirements for black start resources to remove minimum tank suction level from the key work activities. The issue is being considered instead under the recently approved issue charge on black start unit involuntary termination and substitution rules.

Members Committee

1. Transparency and End-of-life Planning (1:25-2:10)

See MRC agenda item 4.

— Rich Heidorn Jr.

Energy Harbor to Pay OVEC $32.5M in Settlement

Drops Bid to Abrogate Contract

By Rich Heidorn Jr.

Energy Harbor has agreed to pay Ohio Valley Electric Corp. (OVEC) $32.5 million and drop its attempt to abrogate a 30-year power purchase agreement signed by its predecessor, bankrupt FirstEnergy Solutions (FES).

Ohio Valley Electric Corp.'s Kyger Creek Power Plant, a 1.08-GW coal-fired generator south of Cheshire, Ohio

In a settlement lodged with FERC on May 19, the companies said Energy Harbor will assume FES' obligations under the multiparty inter-company power agreement (ICPA) as of June 1 and pay OVEC $32.5 million "for any cure costs associated with such assumption."

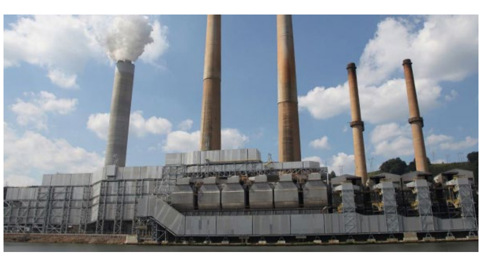
OVEC agreed to waive all claims against FES and Energy Harbor arising prior to June 1 and withdraw a complaint it filed with FERC before FES' bankruptcy and its appeal of the bankruptcy court order confirming FES' reorganization.

Under the ICPA, which runs through June 30, 2040, OVEC provides power from its two coal-fired generating plants — the 1.1-GW Kyger Creek in Cheshire, Ohio, and 1.3-GW Clifty Creek in Madison, Ind. — to Energy Harbor and seven other corporate "sponsors." FES signed the ICPA in 2010, taking a 4.85% "power participation ratio," which required it to pay about $30 million annually to cover OVEC's losses.

Bankruptcy Filing

OVEC filed a complaint on March 26, 2018, asking FERC to rule that allowing FES to reject the ICPA under the Bankruptcy Code without first obtaining commission approval violated the Federal Power Act. FES filed its Chapter 11 bankruptcy petition five days later.

In October 2018, OVEC filed a proof of claim seeking $531 million for damages from FES' rejection of the contract. OVEC also sought $29.3 million for power it provided to FES while the company was in bankruptcy.



Energy Harbor is retiring 669 MW of coal-fired generation at the W.H. Sammis plant at the end of this month but rescinded plans to shutter Units 5-7 (1,491 MW) after winning subsidies from the Ohio legislature. | *FirstEnergy Solutions*

FES changed its name to Energy Harbor upon emerging from bankruptcy in February, with former bondholders owning 50% of the equity. In March, FERC ordered a paper hearing to consider FES' attempt to void the OVEC contract and PPAs with wind generators as part of its bankruptcy proceeding (EL20-35). (See *FERC Sets Hearing on FirstEnergy PPAs*.)

The commission acted after the 6th U.S. Circuit Court of Appeals issued a mandate overruling a U.S. bankruptcy court's May 2018 injunction preventing FERC from issuing any order requiring FES to continue complying with the contracts. The appellate court also reversed the bankruptcy court's ruling allowing FES to reject the contracts.

On May 19, the commission granted OVEC and Energy Harbor's request to extend the briefing schedule in the case for 30 days to "allow OVEC to avoid incurring the time and expense of preparing a reply brief that they state is likely to be unnecessary due to" the settlement.

Litigation Costs, Time

OVEC and Energy Harbor said they called a truce to end litigation that could have continued for years and cost millions.

"The parties' disputes have involved complicated legal and factual issues, with appeals now having made their way to the United States Court of Appeals for the Sixth Circuit multiple times," they said. "There is no doubt that the litigation between FES and OVEC has been hard-fought, complex, time-consuming and costly."

The companies also said the settlement will ensure bigger recoveries for FES' creditors. "Creditors of FES will no longer be diluted by OVEC's asserted claim, which, assuming the estimated recoveries in the disclosure statement, would have been entitled to receive cash distributions of over $160 million if allowed in full."

The Bankruptcy Court for the Northern District of Ohio will hold a hearing June 16 to consider the settlement.

Looking Forward

The deal also will allow Energy Harbor's management "to focus on the growth and success of the reorganized business," the companies said. OVEC will waive its claims against FES, including its rejection damages claim of $531 million.

Energy Harbor and OVEC pledged to work together "to reallocate to EH the right to offer its 'power participation ratio' share of OVEC's 'available energy' ... through the offering of energy and capacity" in PJM.

Energy Harbor said that while it continues "to believe that the costs associated with the ICPA are burdensome to their retail business, [Energy Harbor] understand[s] that OVEC is focused on improving its operational cost structure and that recent Ohio state legislation will assist OVEC in maintaining financial stability while doing so."

Ohio House Bill 6 authorized a surcharge on electricity customers to subsidize OVEC's coal plants in Ohio and Indiana and FES' — now Energy Harbor's — Davis-Besse and Perry nuclear plants.

"The reorganized debtors believe that operational improvements and cost savings can be achieved through their ongoing participation in OVEC pursuant to the ICPA, and they are ready, willing and able to assist in those efforts."

Energy Harbor rescinded plans to retire the Beaver Valley nuclear plant in March, citing Pennsylvania's efforts to join the Regional Greenhouse Gas Initiative.

Pitch to Investors: Nuclear Power and Retail

Energy Harbor emerged from bankruptcy with low debt and largely subsidized generation, winning it investment-grade ratings from *Moody's Analytics* and *Standard and Poor's*.

In March, the first month after emerging from bankruptcy, the company *reported* $142 million in revenue and a $124 million net loss, driven largely by $153 million in losses on nuclear decommissioning trust investments. It also repurchased $113 million in company stock, part of a plan to purchase up to $800 million in shares over nine months. Its adjusted cash flow for the month, including its nuclear fuel amortization expense, was $23 million.

An investor slide deck *posted* May 10 touts the company's carbon-free nuclear generation and its retail sales operation, which it says will generate $200 million in annual cash flow by 2022, when it says more than 95% of its free cash flow will come from carbon-free sources.

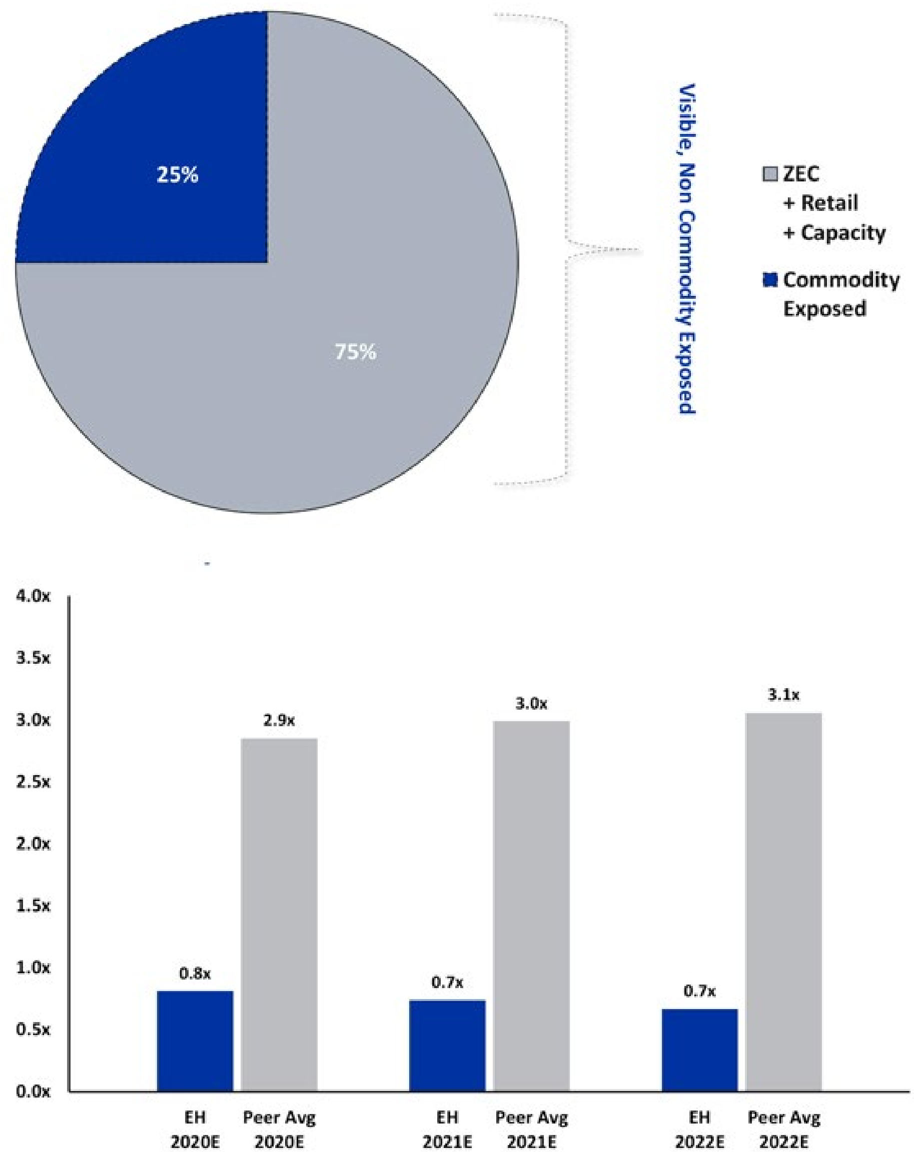
Energy Harbor owns about 7,200 MW of capacity, including three nuclear plants: Beaver Valley Power Station in Shippingport, Pa. (1,872 MW); Davis-Besse Nuclear Power Station in Oak Harbor, Ohio (908 MW); and Perry Nuclear Power Plant in Perry, Ohio (1,268 MW). The company rescinded plans to retire Beaver Valley in March, citing Pennsylvania's efforts to join the Regional Greenhouse Gas Initiative. (See *Beaver Valley Nuclear Plant to Stay Open*.)

The company is retiring the coal-fired Units 1-4 of its W.H. Sammis Plant (669 MW) in Stratton, Ohio, at the end of this month, with a 13-MW diesel unit set to shut down next year. It had also planned to shutter Sammis' coal-fired Units 5-7 (1,491 MW) in 2022, but FES rescinded the notice last year in response to Ohio House Bill 6. Its coal-fired Pleasants Power Station (1,278 MW) in Willow Island, W.Va., is set to retire in June 2022.

Three-quarters of its cash flow comes from nuclear zero-emission credits, plus capacity payments and retail sales, leaving only 25% "commodity exposed," it says.

It notes its gross debt-to-cash-flow ratio is only 0.8, less than a third of the "peer average" of 2.9.

Another selling point: The "company [is] not expected to be a material federal cash taxpayer for [the] foreseeable future." ■



Newly emerged from bankruptcy, Energy Harbor is using its cash flow and low debt to attract investors. | *Energy Harbor*

PJM News

TOs: PJM 'At a Crossroads' on Eve of EOL Vote

By Michael Yoder

| © RTO Insider

PJM transmission owners warned in a strongly worded letter Friday that "PJM is at a crossroads" with an upcoming sector-weighted vote on end-of-life (EOL) projects at this Thursday's Markets and Reliability Committee meeting.

The letter to the PJM Board of Managers said a proposal from a "handful of stakeholders" violates the Consolidated Transmission Owners Agreement (CTOA) between TOs and the RTO. It was signed by 10 of the 14 members of the TO sector: American Electric Power; Dayton Power and Light; Duquesne Light Co.; East Kentucky Power Cooperative; Exelon; FirstEnergy; PPL; Public Service Electric and Gas; UGI; and Dominion Energy.

The joint stakeholder proposal, brought by a group that includes American Municipal Power, Old Dominion Electric Cooperative state consumer advocates, the Public Power Association of New Jersey and the PJM Industrial Customer Coalition, would require TOs to notify PJM and stakeholders of any facility nearing the end of its life at least six years before its retirement date so the project could be included in five-year planning models and potentially opened to competitive bidding. The proposal would also modify the supplemental project definition to exclude EOL projects, which would become a new category of regionally planned projects.

A second proposal from PJM and endorsed by the TOs would require TOs to share how they make EOL determinations and potentially open at least some replacement projects to competition under the Regional Transmission Expansion Plan (RTEP) if they "overlap" with RTEP violations. The proposals are the result of deliberations over special MRC meetings since December.

The TOs said they "demand action" by the PJM board to "uphold the integrity of the stakeholder process" by presenting comments to the Members Committee prior to a vote being taken on either of the proposals.

"The stakeholder process moves forward with the specific objective of certain participants seemingly to leverage the stakeholder process to place PJM in the potentially awkward position of feeling compelled to make a FERC filing that it believes is legally flawed and operationally misguided," the letter said. "Dialogue and the exchange of ideas is essential to the collaborative approach of PJM; however, where issues have been definitively decided by FERC, the continued debate of settled law is no longer dialogue; it is a dissent that should be appropriately appealed to the courts, rather than pursued in PJM committees."

The TO letter comes on the heels of a contentious special meeting of the MRC on May 15 at which LS Power dropped its EOL initiative and endorsed the joint stakeholder proposal. (See TOs Back PJM End-of-Life Proposal.)

The joint stakeholders sent their own letter to the board on May 12 highlighting the "the mounting evidence that the majority of transmission planning in the PJM footprint is not occurring on a regional basis." The letter came as PJM reported that TOs' supplemental projects totaled almost $3.4 billion in 2019, more than double the less than $1.5 billion in regionally planned baseline projects. It was the fifth year out of the last six in which supplemental projects exceeded baseline projects. (See Stakeholders Urge PJM: Plan 'Grid of the Future'.)

The TOs' letter said the stakeholder proposals would impair system reliability and safety by taking EOL decisions away from the TOs and transferring planning authority to PJM. It argued that EOL issues are a subset of asset management and that decisions over those projects "are the sole responsibility of the transmission owners."

The TOs said they were supporting the PJM proposal to increase transparency in the EOL process while preserving their responsibility for maintaining assets.

Responding Saturday to the TO letter, Sharon Segner, vice president of LS Power, said the TOs' May 7 notification that they were considering a Federal Power Act Section 205 filing to amend the Tariff as an alternative to the proposals under consideration was an attempt to "memorialize a world of the transmission owners planning the grid of the future, not PJM."

Segner said the joint stakeholder package puts PJM at the head of planning the future grid after TOs have made the technical determination that an asset is at the end of its operational life.

"We hope PJM embraces a world of PJM planning the grid of the future related to transmission facilities under their operational control," Segner said. "FERC will ultimately decide these issues, and the board should move these issues quickly to FERC from the stakeholder process, should the members pass the Operating Agreement changes on Thursday."

The TOs said PJM is planning the future grid "effectively in collaboration with transmission and generation owners."

"It is undeniable that we have to maintain the current transmission grid to serve our customers while preparing ourselves for the future," the letter said. "It is not an either/or decision between the current and the future; we must address both." ■

PJM News

Public Citizen Denied Rehearing over PJM Political Spending

Non-voting Members Given Finance Committee Access

By Michael Yoder


Tyson Slocum, Public Citizen | *© RTO Insider*

FERC on Thursday denied Public Citizen's request to rehear its original complaint alleging that PJM failed to disclose nearly $500,000 in political spending purportedly financed with membership fees collected from rates.

The consumer advocacy group asked the commission in 2018 to force PJM to itemize all political-related spending after it accused the RTO of contributing $456,500 to both the Democratic and Republican governors associations since 2007 without telling stakeholders or FERC about it, as required by its own Operating Agreement and the Federal Power Act (*EL18-61*). (See *Advocate Group Questions PJM Campaign Contributions*.)

PJM said the contributions support educational services and argued that its Finance Committee provides appropriate oversight of how the RTO spends rate revenues through a stakeholder process.

FERC ruled against Public Citizen's complaint in October, rejecting arguments that PJM should provide greater transparency into budgetary items spent on "outside services" that may have included political advocacy. (See *PJM Political Spending OK, FERC Says*.)

The group filed a rehearing request on Nov. 18, contending that FERC's findings "rests on twin errors," including that PJM's financial contributions to political action committees are "just and reasonable because PJM's intent was noble" and that stakeholders are "empowered to independently oversee PJM's finances and raise questions about PJM's spending."

In its ruling Thursday, FERC said it was "unpersuaded" by Public Citizen's argument that contributions to the governors associations are done to provide "special access" to elected officials. FERC said the commission evaluates lobbying-type expenditures if they represent an educational or informational function of the RTO and if it supports policies the RTO determines to be in the best interest of its stakeholders and for which it cannot receive financial benefits.

"The commission agreed with PJM that, by paying membership fees to the DGA and RGA, PJM maintains access to these organizations to keep informed on policy initiatives impacting the wholesale markets and to help educate state policymakers on PJM activities, and such expenditures are directly related to advancing PJM's stakeholder interests," FERC wrote. "Further, the commission noted that attending DGA and RGA meetings is a cost-effective way of engaging on policy matters where the governors of PJM's 13 states and their staffs are present."

On the oversight of financial expenditures by stakeholders, FERC said PJM's Finance Committee, which includes consumer advocate stakeholders, represents the views of stakeholders adequately. FERC also said that since PJM does not have shareholders, there is less of a profit motive for expenditures that are not in the interest of stakeholders.

Public Citizen also argued that it is barred from attending, monitoring or participating in Finance Committee meetings and had no ability to challenge expenditures.

"Public Citizen could join PJM as a non-voting member and thus be able to represent its interests by attending PJM Finance Committee meetings and expressing its views on PJM proposals," FERC wrote.

Representatives from Public Citizen called FERC's decision a "partial victory for transparency," as the commission acknowledged that non-voting members could participate in Finance Committee meetings.

"We view this as a clear FERC acknowledgment that PJM's closed Finance Committee meetings should be open to active participation by Public Citizen and other public interest groups," said Tyson Slocum, director of Public Citizen's energy program. "We intend to vigorously participate in such meetings to ensure the public's money is being wisely spent." ■

Contribution Date	Amount	Recipient
8/15/2017	$ 25,000	Democratic Governors Assn
5/12/2017	$ 25,000	Republican Governors Assn
6/21/2016	$ 25,000	Democratic Governors Assn
6/17/2016	$ 25,000	Republican Governors Assn
10/15/2015	$ 25,450	Republican Governors Assn
6/22/2015	$ 25,000	Democratic Governors Assn
12/16/2014	$ 26,050	Democratic Governors Assn
11/10/2014	$ 25,450	Republican Governors Assn
11/4/2013	$ 25,450	Republican Governors Assn
7/8/2013	$ 25,700	Democratic Governors Assn
6/5/2012	$ 25,000	Democratic Governors Assn
4/23/2012	$ 25,000	Republican Governors Assn
11/18/2011	$ 25,450	Republican Governors Assn
6/1/2011	$ 25,250	Democratic Governors Assn
10/20/2010	$ 25,450	Republican Governors Assn
9/30/2010	$ 25,500	Democratic Governors Assn
10/21/2009	$ 25,750	Democratic Governors Assn
10/16/2008	$ 25,750	Democratic Governors Assn
10/25/2007	$ 250	Democratic Governors Assn
Total PJM	**$ 456,500**	

Public Citizen identified $456,500 in campaign contributions made by PJM to the Democratic and Republican governors associations since 2007. | *Public Citizen*

SPP News

SPP, Stakeholders Honor Nick Brown in Retirement

Virtual Honors After 16 Years as CEO, 35 with RTO

By Tom Kleckner

Nick Brown in 2019 | © *RTO Insider*

SPP staff and stakeholders on Friday lauded retired CEO Nick Brown for his leadership in building the RTO from a small regional organization into one that now reaches from the Texas Panhandle to the Dakotas.

Given the new normal, the celebration was a virtual one. Brown, sporting his usual SPP-logoed shirt, sat at home next to his wife, Susan, and watched as former and current staffers, directors, regulators and industry insiders praised him for the RTO's success during his tenure.

Brown announced his retirement last July after 35 years with the grid operator, including 16 as CEO. (See *SPP's Brown to Retire as CEO in 2020*.)

American Electric Power CEO Nick Akins invited Brown to Columbus, Ohio, for a game of golf and to share his expertise. The two were classmates at Louisiana Tech (Class of '82), where they went by Nick A. and Nick B. to avoid confusion, and began working at Southwestern Electric Power Co. on the same day.

"He will leave a lasting legacy for SPP and the industry," Akins said.

Former FERC Commissioner Colette Honorable, who also chaired the Arkansas Public Service Commission, toasted Brown with a glass of New Mexico bubbly and thanked him for exhibiting a collaborative approach with stakeholders, rather than "fighting everything at FERC."

Omaha Public Power District's Joe Lang re-

Nick Brown (left) confers with SPP colleagues Claudia Milam and Frank Royster in 1995. | *SPP*

called his first stakeholder meeting. Brown, as he always does during opening introductions, referred to himself as, "Nick Brown, SPP staff."

"That's when it hit me that SPP's inclusive culture is driven from the top," Lang said.

Harry Skilton, an SPP director for 18 years, welcomed the ex-CEO to the RTO's alumni club.

"We're a small group. There's no dues or initiation ceremony," Skilton said. "The only thing I ask of you is that anytime any of us should meet, to raise a good glass of claret to SPP and its motto, 'Keep the lights on.'"

CEO Barbara Sugg credited her predecessor with inspiring her to reach beyond herself when she joined SPP. Sugg was appointed to replace Brown in January. (See *SPP Board Taps Barbara Sugg as New CEO*.)

"He believed in me. He saw things in me I didn't see in myself," she said. "He always set really high expectations and challenged us to meet those expectations. You can't make people follow you. They follow you because you inspire them. I'm proud, I'm humbled, and I'm overwhelmed, in this crazy pandemic, to be stepping into his footsteps."

Sugg assured those watching and listening that she will continue to "foster all those great things" Brown put in place.

"Nick poured his heart and soul and the vast majority of his life into SPP," she said.

Brown's retirement was effective in April. SPP had planned a dinner and celebration in his honor that month, but the coronavirus pandemic waylaid those plans.

Board of Directors Chair Larry Altenbaumer said, "It made sense to go forward at this time and conduct the event sooner, rather than later, in the same manner in which many of us are conducting our daily lives."

When it came his time to speak into his wireless device, Brown recalled that when he joined SPP in 1985, SWEPCO CEO John Turk asked him whether he was sure what he was doing. After all, the organization only had five employees at the time, and Brown had already established himself as a gregarious, outgoing person.

"How are you going to be who you are when you love being around people so much?"

Nick Brown with his gift from the SPP board, a bronze sculpture | *SPP*

Brown, noting that SPP had about 300 stakeholders already, said he would do just fine.

"It's just been a tremendous ride," Brown said. "I've really kind of enjoyed having all of these weeks, from the official retirement day until today, spending time, thinking of each and every person who has touched me in this industry. We've shared blood, sweat and tears. This has been an exciting experience, that's for sure, but things change and things move on.

Brown led the organization as it was recognized by FERC as an RTO and expanded into 14 states, admitting Nebraska utilities in 2009 and the Integrated System in 2015. SPP added a balancing market in 2007 and a wholesale day-ahead market in 2014, while also investing nearly $10 billion in transmission facilities. It became a reliability coordinator in the Western Interconnection in 2019 and will also manage an energy imbalance service market with eight western participants next year.

SPP's membership will reach 100 members when EDF Renewables joins on June 1. The grid operator already has almost 24 GW of installed capacity and has produced as much as 78% of its energy from renewable sources.

The Board of Directors and Members Committee presented Brown with a resolution of "deep gratitude" recognizing his "unparalleled leadership." Earlier in the day, they delivered to his house a bronze *sculpture*, titled "Place of Honor," by his and Susan's favorite artist, Colorado sculptor Joshua Tobey.

"I couldn't be more pleased with the position the organization is in," Brown said. "With the board and the management team, and with Barbara as the new CEO, the future is great. I'm really excited to watch the organization continue to prosper," Brown said. "Thank you. Thank you. Thank you, very much." ■

SPP News

FERC Partially Accepts Tri-State Order 845 Filing

FERC last week partially approved Tri-State Generation and Transmission Association's Order 845 compliance filing, directing the Colorado cooperative to make additional changes within 120 days (*ER20-687*).

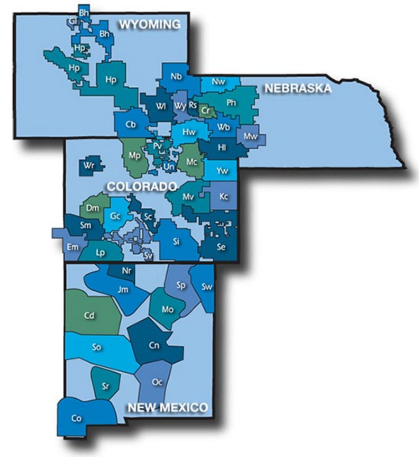
The commission on Thursday accepted most of Tri-State's compliance filing but said the cooperative only partially complied with Orders 845 and 845-A's requirements regarding surplus interconnection service and determining contingent transmission facilities. It directed Tri-State to describe the specific technical screens or analyses and the triggering thresholds or criteria it will use to determine which facilities are contingent facilities — unbuilt interconnection facilities and network upgrades upon which an interconnection request's costs and timing are dependent.

It also ordered the cooperative to explain why it omitted the sentence "Surplus interconnection service requests also may be made by another interconnection customer" from its proposed large generator interconnection procedures. Surplus service is any unused portion of interconnection service.

FERC issued Orders 845 and 845-A in 2018 and 2019 to increase the generator interconnection process' transparency and speed. The changes are grouped into three categories: improved certainty for interconnection customers; promoting more informed interconnection decisions; and process improvements. (See *FERC Order Seeks to Reduce Time, Uncertainty on Interconnections*.)

The commission on Thursday also accepted Tri-State's large generator interconnection agreement with Leeward Renewable Energy as a service agreement under the cooperative's Tariff, effective Feb. 25, and established hearing and settlement procedures to address unresolved issues between Tri-State and Leeward (*ER20-1045*).

Tri-State became FERC-jurisdictional in March, when the commission recognized its status following last year's addition of its first non-utility member. (See "Ruling Permits Tri-State to Become FERC Jurisdictional," *SPP FERC Briefs: Week of March 16, 2020*.) ■



Tri-State G&T's service territory | *Tri-State*

— Tom Kleckner

EDF Renewables to Become SPP's 100th Member

SPP will soon reach a significant milestone when it adds its 100th member in global renewable developer EDF Renewables.

CEO Barbara Sugg said in an email to stakeholders that France-based EDF will become a full-fledged member on June 1. The company develops, builds and operates clean energy power facilities in more than 20 countries. It has installed 12.6 GW of capacity around the globe.

Arash Ghodsian, EDF's senior director of transmission strategy and policy, said the company was pleased to partner with SPP and its "long history of keeping the lights on, thanks to a resourceful staff, a sound governance structure and an open stakeholder process."

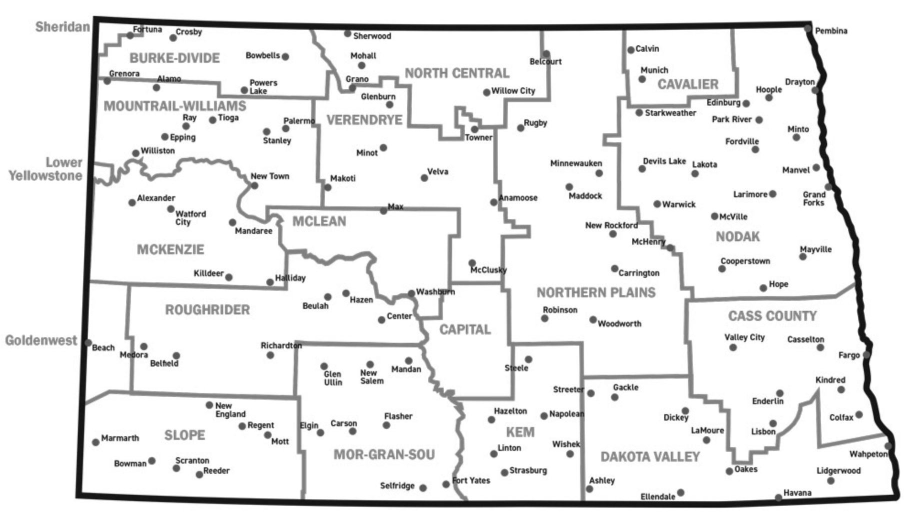
The RTO previously added *Roughrider Electric Cooperative* as its 99th member on April 30. The North Dakota distribution cooperative serves more than 8,000 members in six counties. It purchases power through Montana's Upper Missouri Generation & Transmission Cooperative and also sources energy from SPP members Basin Electric Power Cooperative and Western Area Power Administration.

Sugg also said SPP is planning to begin returning non-operations staff to its Arkansas facilities on July 6, assuming a 14-day downward trajectory of new cases in the state and that other criteria are met. Employees will return to their workplaces in a phased approach, 20% at a time, Sugg said in April.

"Rest assured we are carefully monitoring the pandemic as it evolves and are continuing to put the safety and well-being of our employees at the top of our priority list," she said.

SPP on May 7 extended its suspension of all business travel and in-person meetings until Aug. 1, at the earliest. ■

— Tom Kleckner



North Dakota's cooperatives | *NDAREC*

Company Briefs

Amazon to Buy More than 600 MW of Large-scale Solar

Amazon last week said it will add 615 MW of solar projects to its existing and announced renewables portfolio of more than 2.9 GW in Australia, China and the United States to power its shipping warehouses and data centers.

The largest additions will come in the U.S. where the company will add two solar installations in Ohio and Virginia for a total of 410 MW.

Amazon has not ranked in the top five corporate purchasers in the nation since 2016 when it was the largest annual purchaser, according to the Renewable Energy Buyers Alliance.

More: *GreenTech Media*

Energy Bar Association Names New President, Board Officers

The Energy Bar Association last week elected **Jane Rueger** of Perkins Coie as the new president of its 2020-2021 board of directors. The election took place via a virtual conference on April 15. (See *EBA Holds Annual Meeting Online Successfully*.)

In addition to electing Rueger as president, EBA elected the following individuals to be board officers: Mosby G. Perrow IV, of Kinder Morgan, as president-elect; Delia D. Patterson, of the American Public Power Association, as vice president; Paul M. Breakman, of National Rural Electric Cooperative Association, as secretary; David Martin Connelly, of Jones Day, as assistant secretary; Richard G. Smead, of RBN Energy, as treasurer; and Nicholas Pascale, of the National Rural Electric Cooperative Association, as assistant treasurer.

Former FERC Lawyer Joins Jenner & Block as Partner

Jenner & Block last week announced that Jennifer Amerkhail has joined its firm as a partner at its D.C., office. Amerkhail, a member of the firm's energy practice, is a former FERC lawyer who most recently served as in-house counsel representing Entergy's utility operating companies.

Amerkhail served as assistant general counsel for Entergy's FERC legal group. In her time at Entergy, she litigated return on equity and capital structure issues in cost-of-service rate cases before FERC's administrative law judges.

More: *Jenner & Block*

GenOn to Close Three Coal-fired Units

GenOn Holdings last week said it will close Units 1, 2 and 3 at its coal-fired Dickerson Generating Station in Maryland because of "unfavorable economic conditions and increased costs associated with environmental compliance." The decision is subject to a 90-day reliability review by PJM, after which the company will initiate a deactivation process and plan to reduce the plant's workforce.

Together, the units account for about 540 MW of generation capacity. The requested deactivation date is Aug. 13, according to PJM's website.

The company also said as many as 63 workers could lose their jobs as of Aug. 1.

More: *POWER Magazine*

ISO-NE Expects Sufficient Resources for Summer Demand

ISO-NE last week said it expects to have sufficient resources to meet peak demand this summer under both typical and extreme weather conditions, as more than 33,000 MW of capacity are expected to be available. The forecast includes a reduction of nearly 800 MW during the peak hour that can be expected from behind-the-meter PV installations.

Societal changes in response to the COVID-19 pandemic are also expected to change demand during the summer but do not pose a reliability threat. The RTO has so far observed a 3-5% decline in demand because of the pandemic.

More: *ISO-NE*

SGH2 to Launch World's Largest Green Hydrogen Project

Global energy company SGH2 last week said it has a deal with Lancaster, Calif., to build what it calls the world's biggest green hydrogen production plant. It is set to be in full operation in early 2023.

The company said the $55 million project will feature technology that uses recycled mixed paper waste to produce "greener than green" hydrogen and that the process reduces carbon emissions more than green hydrogen produced using electrolysis and renewable energy. It uses a plasma heating technology, originally developed for NASA, which disintegrates recyclables at around 7,000 degrees.

The Solena Group, SGH2's parent company, does not yet have financing for the project.

More: *POWER Magazine*

Siemens Gamesa Appoints North America Onshore Chief

Siemens Gamesa last week announced that it has appointed Shannon Sturgil, effective from June 1, as the company's North America onshore chief executive. Sturgil will succeed Jose Antonio Miranda, who plans to return to Spain.

Sturgil has worked under the Siemens umbrella for 20 years. His most recent role was head of power systems sales at Siemens Energy.

More: *Renews*

Texas Renewables Energy Industries Alliance, CleanTX Merge

The Texas Renewable Energy Industries Alliance (TREIA) and CleanTX announced last week that they have joined forces to accelerate the growth of the clean and renewable energy industries in Texas.

CleanTX, founded in 2006, is an economic development and professional association for the cleantech industry. It supports cleantech innovation and adoption through information exchange, thought leadership and strategic partnerships. The merged group will operate under the CleanTX name.

TREIA holds the annual GridNEXT conference to discuss grid modernization and renewable integration. The newly merged organization announced that this year's *conference* would be held virtually on Aug. 19 because of the COVID-19 pandemic.

More: *CleanTX*

FERC Partially Approves Duke Order 845 Compliance Filing

FERC on Thursday found that several Duke Energy subsidiaries must once again file more changes to their joint open access transmission tariff to comply with Order 845.

Order 845 amended the commission's *pro forma* large generator interconnection agreement and procedures to increase the efficiency of the interconnection process. Duke's Carolinas, Florida and Progress utilities filed their second compliance filing in February, after the commission found their initial filing in April 2019 only partially complied with the order.

FERC had directed the utilities to include explanations of studies they will conduct to determine whether a proposed technological change to a generation resource seeking to interconnect would be a material modification, and to detail the specific technical screens or analyses and the specific thresholds or criteria that they will use as part of their method to identify contingent facilities, among other minor revisions.

The utilities mostly complied with these directives, the commission found, but it found other minor deficiencies. For example, it found that the utilities had proposed giving themselves 40 days to review a technical change request and complete all the required studies, when the order mandated only 30 days. It ordered the utilities to file another compliance filing within 120 days.

More: *ER19-1507-005*

Federal Briefs

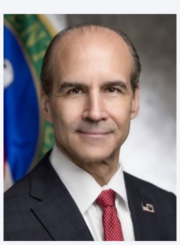
Court Rules EPA Must Protect States from Upwind Air Pollution

A three-judge panel of the D.C. Circuit Court of Appeals last week ruled EPA violated the law when it denied a request from Maryland and Delaware to tighten air pollution controls at power plants in upwind neighboring states. The decision could force the agency to impose new rules on some coal-fired plants, even as the Trump administration seeks to help the industry by slashing regulations.

Maryland and Delaware filed a petition in 2018 asking for tougher pollution limits on some 36 coal-fired plants in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia. The states argued those plants were in violation of the Clean Air Act's "good neighbor provision" for the release of nitrogen oxides into the air. EPA rejected the request, saying that requiring the plants to add more pollution controls was not cost-effective for the plant owners.

More: *Reuters*

Menezes Shifts Stance on Yucca Mountain



Mark Menezes, President Trump's nominee for deputy energy secretary, last week clarified remarks he made in February and now says the administration does not have plans to use Yucca Mountain in Nevada as a nuclear waste storage site.

"The administration will not be pursuing Yucca Mountain as a solution for nuclear waste, and I am fully supportive of the president's decision and applaud him for taking action when so many have failed to do so," Menezes told Sen. Catherine Cortez Masto (D-Nev.) at his confirmation hearing before the Senate Energy and Natural Resources Committee.

In February, Menezes said the department was trying to "put together a process that will give us a path to permanent storage at Yucca." However, Trump had already said he was committed to other alternatives.

More: *Las Vegas Review-Journal*

LCV Calls for Brouillette's Resignation Following 'Redlining' Comment

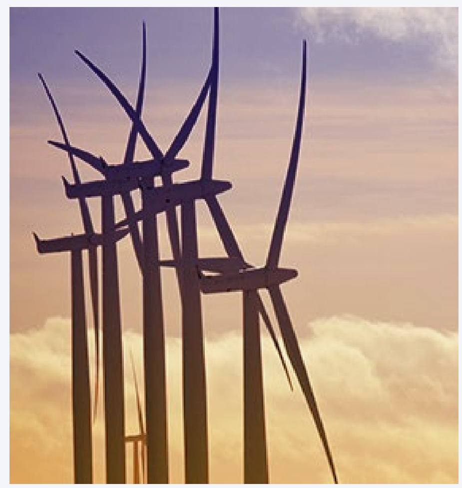
The League of Conservation Voters last week called for the resignation of Energy Secretary Dan Brouillette after, in an interview with Axios, he said he did not want banks to be "redlining" oil and gas in response to five of the six biggest banks in the U.S. recently saying they will not finance oil and gas development in the Arctic.

Redlining refers to discriminatory tactics used to prevent minorities from buying homes, as banks systematically declined to extend loans to applicants in the past who were from areas with large minority populations. The now illegal practice was named such after red lines were drawn on maps to demarcate certain neighborhoods.

Department of Energy spokesperson Shaylyn Hynes attempted to clarify his words, saying, "Secretary Brouillette has zero tolerance for discrimination of any type, and he was not in any way equating the plight of minority communities to that of energy companies."

More: *The Hill*; *Axios*

IEA Expects Green Energy Growth to Fall for 1st Time in 20 Years



Renewable capacity additions for 2020 are set to total 167 GW, which would be 13% less than last year, according to the IEA's Renewable Market Update report. It would be the first decline in new, global renewable energy capacity in the last 20 years, due mainly to the COVID-19 pandemic. However, the agency does expect the growth to pick back up the following year.

"Countries are continuing to build new wind turbines and solar plants, but at a much slower pace," IEA Executive Director Fatih Birol said.

Growth for 2020 and 2021 combined is expected to be 10% lower than the IEA had previously forecast before the outbreak. Still, overall global renewable power capacity is still expanding and will grow by 6% in 2020.

More: *Reuters*

Senate Confirms 5th NRC Commissioner

The Senate last week confirmed Christopher Hanson as a member of the Nuclear Regulatory Commission via voice vote, giving the five-member commission a full slate for the first time in about a year.

Hanson currently serves as a minority professional staff member on the Senate Appropriations Committee's Energy and Water Subcommittee. He will begin a term to end June 30, 2024.

The Senate also confirmed sitting Commissioner David Wright, who joined NRC in May 2018, for a second term to begin July 1 and end in 2025. Wright is a former president of the National Association of Regulatory Utility Commissioners and former chairman of the South Carolina Public Service Commission.

More: *Senate Environment and Public Works Committee*

State Briefs

CALIFORNIA

UC Becomes Largest University to Fully Divest from Fossil Fuels

The University of California last week announced it has fully divested from all fossil fuels, becoming the largest educational institution in the U.S. to do so. The milestone capped a five-year effort to move the university system's $126 billion portfolio into more environmentally sustainable investments.

"As long-term investors, we believe the university and its stakeholders are much better served by investing in promising opportunities in the alternative energy field rather than gambling on oil and gas," Richard Sherman, chair of the UC Board of Regents' investments committee, said in a statement.

More: *Los Angeles Times*

PG&E Seeks Approval for New Battery Storage

Pacific Gas and Electric last week asked the Public Utilities Commission to approve five separate storage projects totaling 423 MW, intended to further integrate renewable sources and ensure future reliability of the grid.

The projects feature lithium-ion battery storage systems with a four-hour discharge duration. They are to be co-located with renewable plants or be built as part of new standalone projects, and would fulfill more than half of the 717 MW of system reliability resources PG&E was authorized to procure to come online between Aug. 1, 2021, and Aug. 1, 2023.

More: *Renew Economy*

COLORADO

City of Fountain Strikes Electricity Deal

Guzman Energy last week agreed to pay the city of Fountain $12.2 million in monthly installments through 2027 to secure the city as a customer from 2028 through 2039. The payments are set to start in July, with residents expecting a 4% reduction on their bills starting in August.

Fountain will honor its current contract with the Public Service Company of Colorado, which lasts through 2027, while passing on Guzman's payments as savings to customers, Fountain Utilities Director Curtis Mitchell said.

More: *The Gazette*

Holy Cross Seeks More Resilient Power Supply Following Fire

The Rocky Mountain Institute last week released a study examining Holy Cross Energy's work to boost energy resiliency in the Roaring Fork Valley following the Lake Christine Fire in Basalt in July 2018.

The goal of the study is to create a more resilient system so if another wildfire torches power poles in the Basalt State Wildlife Area or a major blizzard causes a multiday outage, residences and businesses aren't left in the dark, according to Holy Cross CEO Brian Hannegan.

The Holy Cross system was barely standing during the thick of the fire, with three of the four transmission lines running into Aspen disabled. The company has since "hardened" its grid infrastructure and placed fire-retardant wrapping on several poles. It is also working with Aspen-Pitkin County Airport and the Aspen Business Center on a microgrid that could be used to keep essential services operating during a sustained outage.

More: *The Aspen Times*

IOWA

Utilities Board says Disconnections Can Resume on May 28

The Utilities Board last week announced that municipally owned utilities can resume disconnections on May 28, while investor-owned utilities can begin on July 1.

The board said that if a customer already has received a 12-day disconnection notice, utilities must issue another seven-day notice, although they do not need to wait until May 28 to issue the notice. There are exceptions for anyone who is quarantined after testing positive for COVID-19 and anyone with a "health condition that requires the use of electric or natural gas service."

More: *The Gazette*

KANSAS

Roeland Park Sets Deadline to Reduce Carbon Emissions

The Roeland Park City Council last week approved a resolution setting 2025 as a goal to reduce the city's carbon emissions by 28%. The date and goal complies with the 2015 Paris Agreement's recommendations.

One key strategy is implementing more renewable energy sources, and the city has already discussed using solar energy sources at its city hall, aquatic center and community center.

The council also approved an ordinance requiring all new residential and commercial construction to be fitted with a roof and electrical system that could accommodate a solar panel array.

More: *Shawnee Mission Post*

LOUISIANA

New Orleans Directs Entergy to Cover Unemployed Residents' Bills

The New Orleans City Council last week announced a program with Entergy that will give unemployed residents $100 a month for up to four months to cover their bills. Entergy New Orleans will be directed to pull roughly $22 million, mostly from its reserves, to cover the costs.

City officials said the help is needed, as 40% of Entergy's customers have fallen behind on their bills in the months since the COVID-19 pandemic began and the utility announced it would suspend shutoffs for nonpayment. Now, residential customers will be eligible for a $400 credit if they provide proof of unemployment. The average monthly residential bill is $110.

The council also ordered Entergy to extend shutoff suspensions until July 1. The program will become official when the council formally approves it next month.

More: *The New Orleans Advocate*

NEW YORK

LIPA Planning to Retire 1 Northport Unit

The Long Island Power Authority (LIPA) said last week it plans to retire at least unit at its gas-fired Northport Power Station and will make a decision on which one by year-end.

Projections show the plant will be used less over the next 10 years, and a LIPA study found the most cost-effective move would be to retire one of the four units, saving ratepayers $303 million over 20 years.

LIPA CEO Thomas Falcone said the first retirement of 400 to 600 MW of capacity would be followed by additional retirements after 2024.

More: *Newsday*

Panasonic to Resume Work at Tesla's Solar Factory

Panasonic restarted production at Tesla's Buffalo solar panel factory last week after the factory sat idle for roughly two months.

Mark Shima, the president of Panasonic's North American solar energy division, said the company has "completed preparations under close collaboration with Tesla" and that employees will have to go through a pandemic safety training before their first shift. The company originally planned to bring employees back on May 16 but had to delay restarting because the region did not meet Gov. Andrew Cuomo's criteria for reopening.

Panasonic announced plans to end its involvement at the Buffalo factory earlier this year, but the shutdown robbed the company of two months of production. With that, the company will now operate in the factory until the end of June and fully exit the factory in September.

More: *The Verge*

OHIO

Regulators Insist on Wind Farm Stipulation that May Kill Project

The Power Siting Board last week ruled that the Icebreaker wind project could move forward, but only if blades on the demonstration project's six turbines are turned off every night for eight months of the year.

After months of negotiations between developer Lake Erie Energy Development Corp., PSB staff and the Department of Natural Resources, a compromise was reached last May that dropped the requirement. However, despite an ornithologist saying it was "the lowest-risk project" he ever worked on, the board shifted its position to set a precedent for future projects.

LEEDCo President Dave Karpinski said the condition "may well be fatal to the entire project," as shutting down generation for that much of the year would greatly reduce the amount of revenue the project could produce.

More: *Energy News Network*

TEXAS

CenterPoint to Close Power Shopping Site

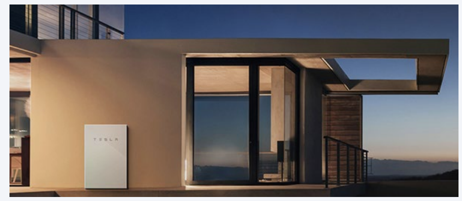
CenterPoint Energy said it would shut down its online electricity shopping site *True Cost* on Monday to focus on its core utility business. Interim CEO John W. Somerhalder II told investors that the utility portion of the business is expected to generate nearly 90% of the company's earnings moving forward.

The company set up its electricity brokerage operation eight years ago through its unregulated businesses and later expanded to include home warranties for water heaters, cooling systems and gas lines.

More: *Houston Chronicle*

VERMONT

PUC Approves GMP Storage Programs



The Public Utility Commission last week approved two new home battery programs from Green Mountain Power (GMP). Enrollment will start on June 5.

GMP's Tesla Powerwall and Bring Your Own Device (BYOD) programs are modeled on pilots that have shown to save costs while providing backup power during outages. GMP is the first utility in the country to get tariff approval to offer these types of programs.

The BYOD tariff offers up to $10,500 in incentives to customers purchasing their own batteries through local installers. The Powerwall tariff, which allows customers to enroll each year, allows customers to pay $55/month for two batteries in a 10-year lease that covers standard installation, or pay $5,500 upfront.

More: *Vermont Business Magazine*

WISCONSIN

MGE Proposes Solar Farm

Madison Gas and Electric (MGE) announced last week it has filed plans with the Public Service Commission to build the 20-MW O'Brien Solar Fields farm in Fitchburg. The city already granted a conditional-use permit for the project in January.

According to the filing, MGE has contracts with the state, the University of Wisconsin-Madison, Fitchburg, Placon, Promega and Willy Street Co-op to buy about 85% of the energy. The remainder will be contracted out.

If approved, construction of the project is expected to begin in September, with it coming online in summer 2021.

More: *Wisconsin State Journal*