RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

ISSN 2377-8016 : Volume 2020/Issue 23 June 9, 2020

Lawyers Close PG&E Bankruptcy Case

Judge to Rule After 2 Weeks of Testimony and Evidence

By Hudson Sangree

Judge Dennis Montali | *Commercial Law League of America*

Bankruptcy attorneys representing Pacific Gas and Electric summed up their case Monday, telling U.S. Bankruptcy Court Judge Dennis Montali that the utility's reorganization plan is the best possible outcome for wildfire victims and ratepayers.

PG&E lead attorney Stephen Karotkin said rejecting the utility's Chapter 11 reorganization plan, as some fire victims and their lawyers have urged, would lead to "total chaos" and delay compensation for years. None of the objecting parties had presented sufficient evidence to defeat the plan, he argued.

Stephen Karotkin | *Weil, Gotshal & Manges*

"Confirmation is the only path here," Karotkin told the judge.

There are approximately 80,000 fire victims waiting to be compensated for the death of family members, and the loss of homes and businesses, in fires ignited by PG&E equipment in 2015, 2017 and 2018.

Montali now must decide the case. "The ball's in my court to do what's next," he said.

The judge indicated he will try to issue at least a brief order approving or denying the proposal by the end of the week.

Continued on page 5

National Grid, Eversource Finalist for Boston Tx Plan

Incumbents Selected for RTO's First Competitive Project

By Michael Kuser

A $49 million project by incumbent utilities National Grid and Eversource Energy emerged Monday as the lone finalist in ISO-NE's first competitive transmission solicitation under FERC Order 1000.

The RTO announced Monday that it had selected the cheapest of the 36 proposals it received in response to its Boston 2028 transmission solicitation to move forward, obviating a second round of review and moving straight to "solutions studies," to evaluate the adequacy of the proposal.

COO Vamsi Chadalavada last week told the NEPOOL Participants Committee that the RTO was evaluating the proposals and would present its draft list of qualifying Phase One proposals at the Planning Advisory Committee meeting on June 17. But at 1:30 p.m. Monday, the RTO *announced* it had already narrowed the candidates to one project: the $49 million "BOS-017" proposal. (See related story, "Boston RFP and System Disturbances," *NEPOOL Participants Committee Briefs: June 4, 2020*.)

Although the RTO did not identify the winning bidder, National Grid and Eversource Energy issued a *joint press release* June 5 saying they had submitted eight proposals to the Boston request for proposals, ranging from $48 million to $120 million. The RTO said it received 36 Phase One proposals ranging from $49 million to $745 million. The reason for the $1 million discrepancy between the companies' announcement and the RTO's estimate was not immediately clear.

Continued on page 11

CleanPower 2020: Renewables' Future Still Holds Hope

Industry Addressing COVID-19's Effects

By Tom Kleckner

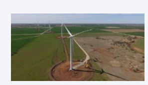
The Block Island Wind Farm, off Rhode Island, leads an offshore sector that was "just taking off." | *Block Island Ferry*

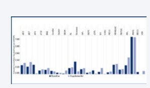
Before the COVID-19 outbreak, the American Wind Energy Association had planned to unveil a new exhibition hub, bringing together the utility-scale wind, solar and energy storage industries at its annual conference and trade show in Denver.

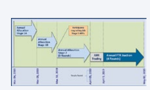
Instead, it settled for a web-accessible three-day event featuring virtual runs, bike rides,

Continued on page 3

Also in this issue:







10837 Deborah Drive ▪ Potomac, MD 20854 ▪ (301) 299-0375 ▪ info@rtoinsider.com ▪ www.rtoinsider.com

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

Editor-in-Chief / Co-Publisher
Rich Heidorn Jr. 202-577-9221

Deputy Editor / Senior Correspondent
Robert Mullin 503-715-6901

Art Director
Mitchell Parizer 718-613-9388

Associate Editor / D.C. Correspondent
Michael Brooks 301-922-7687

Associate Editor
Shawn McFarland 570-856-6738

CAISO/West Correspondent
Hudson Sangree 916-747-3595

ISO-NE/NYISO Correspondent
Michael Kuser 802-681-5581

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Michael Yoder 717-344-4989

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

NERC/ERO Correspondent
Holden Mann 205-370-7844

Subscriptions

Chief Operating Officer / Co-Publisher
Merry Eisner 240-401-7399

Sales Director
Marge Gold 240-750-9423

Account Executive
Kathy Henderson 301-928-1639

Marketing Director
Margo Thomas 480-694-9341

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 299-0375

2020 Annual Subscription Rates:

Plan	Price
Newsletter PDF Only	$1,450
Newsletter PDF Plus Web	$2,000

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

FERC/Federal News

CleanPower 2020: Renewables' Future Still Holds Hope

Industry Addressing COVID-19's Effects

AWEA CEO Tom Kiernan (top left) virtually moderates a panel with (clockwise) NHA's Malcom Woolf, SEIA's Abigail Ross Hopper and ESA's Kelly Speakes-Backman.

Continued from page 1

happy hours and, of course, panel discussions with homebound speakers.

"We knew it would be different," AWEA CEO Tom Kiernan said June 2 in opening remarks from his home. "I sure didn't think it would be this different."

Last year's conference in Houston drew more than 7,000 attendees and more than 450 companies, numbers AWEA was expecting to surpass this year with the rebranded CleanPower 2020. Instead, the organization will have to wait until next year, another disappointment in a year where the pandemic brought much of the economy to a standstill.

The wind industry was coming off a "banner year" in 2019, adding 9.1 GW of capacity to crack the 100-GW barrier and $14 billion in new projects. An "unprecedented" pipeline of projects added to the optimistic outlook. (See *AWEA: COVID-19 Places 25 GW of Projects at Risk*.)

"Obviously, the COVID pandemic was an economic buzz saw for the U.S. and world economy," Kiernan said. "We're facing some significant financing challenges."

Still, AWEA's lobbying efforts in D.C. have resulted in the IRS issuing a *one-year extension* of the safe-harbor provision for wind projects begun in 2016 and 2017, giving developers 12 extra months to qualify for production and investment tax credits.

But there is more work to do, Kiernan said, particularly with an offshore wind sector that was "just taking off." AWEA says the U.S. has 15 active commercial leases for offshore wind development, capable of supporting about 25 GW in capacity.

"We've got to keep that momentum going," he said. "Despite the world's economic challenges, renewables in general — and wind in particular — have a bright and extraordinary future. Why? Economics."

Kiernan said renewables remain the cheapest source of generation. Wind costs have fallen about 70% over the past decade, helping the economics remain "so doggone compelling."

"Utilities are increasingly buying and using renewables," he said, pointing to the 16 GW of power purchase agreements in 2018. "Americans want it, and we're cost effective."

In collaboration with others in the renewable sector, AWEA has put forth a vision of renewables constituting a majority of U.S. capacity by 2030.

"It's tough to think about going to this great bright future from the depths of where we are now," Kiernan said. "We have worked to craft a very simple — a very compelling — vision. Pursuing this vision will create hundreds of thousands of jobs, while providing reliable, clean and cost-effective energy."

Renewable Industries Agree on Advocacy Principles

Kiernan was joined on the webcast by representatives from the solar, hydro and storage industries, who added their thoughts on the majority-renewables-by-2030 vision.

"Having this clear vision is critical. We're very much mainstream right now, but it wasn't too long ago that we were alternative energy," said Malcom Woolf, CEO of the National Hydro Association. "It shows how these technologies work together. We balance each other. We have different attributes that complement each other."

"It's really consistent with who we are as an in-

FERC/Federal News

dustry," said Energy Storage Association CEO Kelly Speakes-Backman. "There's no reason for energy storage to exist without the other sources to our grid. [Storage] is the bacon of the grid; it makes everything a little bit better. We're more than happy to help resources that make cleaner air for all of us."

The associations now share advocacy principles "as critical" to attaining their vision of majority renewables by 2030:

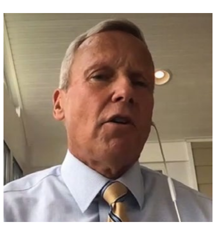
- Achieve significant carbon reductions.
- Build a more resilient, efficient, sustainable and affordable grid.
- Advance great competition through fair market rules.
- Actively collaborate across industry segments.

"Taking that shared vision to [Capitol Hill] and our policy advocacy makes it clear to our own constituencies … that we are creating a vision and markets for all of us," said Abigail Ross Hopper, CEO of the Solar Energy Industries Association. "If you think about the grid itself, it was designed over 100 years ago for centralized power plants. But the rules as centralized power generators have certain attributes that don't allow for a lot of competition.

"It's important we have market rules that compensate generators for their attributes, rather than being for a certain fuel source," she said.

"These principles really lift all boats and help all of our industry," Woolf said. "It's so much more effective when we can work it out behind closed doors before we go to the policymakers."

PJM Panel Pushes Back Against MOPR



Michael Richard, Maryland PSC

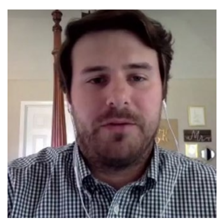
Maryland Public Service Commissioner Michael Richard did not mince words during a panel addressing FERC's December order requiring PJM to overhaul its capacity market by expanding the minimum offer price rule (MOPR) to new state-subsidized resources within its footprint. (See *FERC Extends MOPR to State Subsidies*.)

"We've been very successful in largely being united [against] the MOPR, largely because we agree it's an unlawful intrusion," Richard said, speaking from Maryland's perspective. "Our citizens will be paying more and not getting the clean energy they're demanding. It's an unfair windfall for generators."

State regulators, utilities and load-serving entities have argued in rehearing requests to FERC that the order goes too far in attempting to control their generation choices and fails to prove state-subsidized resources suppress capacity market prices. One of the primary concerns is for offshore wind, which is subsidized by the states and won't be able to clear the capacity market because its default MOPR prices are well above clearing prices.

Maryland is one of those states, with the administration, energy office and commission all opposing the MOPR. Richard said the MOPR tends to unite PJM's states, four of whom are members of the Regional Greenhouse Gas Initiative or are among the 25 states committed to the 2015 Paris Agreement on climate change.

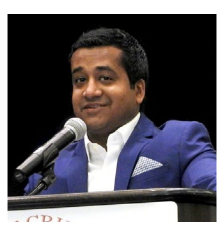
"A majority of our states are moving to decarbonize at different rates. We really need PJM's support for state policies," he said, pointing to PJM states' collective goal of 30 GW of clean energy requirements by 2030. "We're going to need a lot more renewable energy in the PJM footprint. What FERC is doing, in the words of its own orders, is disregard and nullify its own orders. That's a great concern and why we're largely united in opposing the MOPR."



Kent Chandler, Kentucky PSC

"The reality is some states care what color their megawatts are," said Kent Chandler, executive director of the Kentucky Public Service Commission, which oversees a regulated market. "A number of states want green energy, and there are two ways to go about it: either accommodate it or go somewhere else. The only way forward is to accommodate [green energy] somehow.

"There has to be a middle way for some states to get green energy without FERC determining what is some sort of cost shift. I fully expect that by the time the litigation over the MOPR is over, we'll have a different [market] construct by then," he said.



Asim Haque, PJM | © RTO Insider

Asim Haque, PJM's newly minted vice president of state and member services, said the grid operator's recent compliance filing was an effort to balance the various constituencies in its 14-jurisdiction region (13 states and D.C.). (See *PJM Makes MOPR Compliance Filing*.)

"There has to be a middle way for some states to get green energy without FERC determining what is some sort of cost shift. I fully expect that by the time the litigation over the MOPR is over, we'll have a different [market] construct by then."

—Kent Chandler, executive director of the Kentucky Public Service Commission

"We have a very diverse footprint. We view that as a strength. It's a wonderful microcosm of the country at large," Haque said. "It creates challenges for PJM because when we think about where PJM is in a situation like this, we're trying to homogenize various market priorities to advance particular fuel types or technologies, without detriments to others.

"Look at the compliance filing," Haque said. "We worked hard to accommodate as many state policies as we could. The hope is we get through collectively this MOPR phase of the capacity market. Getting through this iteration doesn't necessarily [solve] the larger problem of how we homogenize these different market priorities within one larger construct."

Greg Poulos, executive director of Consumer Advocates of the PJM States, said stakeholders have already begun to evaluate PJM's market design, given its 26% reserve margin, requirements to add 10 GW of wind resources by 2029 and decarbonization discussions.

"The MOPR order hasn't been implemented yet and already there are thoughts of 'what do we do now?'" he said. "There's a clear understanding PJM doesn't have the ability to implement carbon pricing without the states taking some action. But what are we going to do with [10 GW of wind resources]? There's not an answer right now. There's a lot of excess resources, with a lot of resources coming on. How do we pay for all these resources and make it more effective? We're already thinking about that." ■

CAISO/West News

Lawyers Close PG&E Bankruptcy Case

Judge to Rule After 2 Weeks of Testimony and Evidence

Continued from page 1

"June 30 lurks out there," Montali said, referring to the deadline for PG&E to exit bankruptcy to participate in a $21 billion state wildfire insurance fund under last year's Assembly Bill 1054.

Montali thanked the lawyers and participants for their "enormous effort" over the past 16 months. PG&E filed for bankruptcy on Jan. 29, 2019, facing what it said were $30 billion in wildfire liabilities. Its negotiated settlements with fire victims, insurance companies, local governments and others total $25.5 billion.

Monday's hearing capped nearly two weeks of proceedings at the end of the case in which dozens of lawyers and self-represented fire victims spoke for and against the plan.

Victims' Shares Could be Locked up

Last-minute controversies consumed much of the court's time on Friday and Monday.

Attorney Robert Julian, representing the case's official Tort Claimants Committee (TCC) for fire victims, told Montali for the first time Friday that PG&E and the TCC were having a dispute about when fire victims would become eligible to sell the $6.75 billion in stock with which PG&E is planning to fund half of a $13.5 billion victims' trust.

Fire victims will own approximately 20% of PG&E under their settlement agreement with the utility.

Without specific wording in the 2,000-page bankruptcy plan, however, victims could be prevented from selling their newly issued stock for five years under federal regulations, Julian said. Hedge funds that already hold billions of dollars in PG&E equity could sell their shares immediately, he said. Institutional investors and fire victims need to be treated equally, Julian argued.

Robert Julian | *Baker & Hostetler*

Many fire victims have expressed concern that the stock could sink in value if PG&E starts more wildfires or becomes financially unstable from its heavy debt load after leaving bankruptcy.

The discussion continued Monday morning, when Julian and Karotkin said the matter was being mediated by retired bankruptcy Judge Randall Newsome, who has helped resolve major disputes in the case. Karotkin said he was hopeful the disagreement could be settled soon.

"The more things that get resolved, the better," Montali said.

The judge said Monday he would ask Newsome to mediate a conflict between PG&E shareholders and a group of plaintiffs, led by the Public Employees Retirement Association of New Mexico. The association claims PG&E defrauded investors by underplaying for months its potential liability for wildfires.

After the wildfires of October 2017, PG&E's stock price began a steep decline from nearly $70/share to a low of $5 on Oct. 25, 2019. The stock closed Monday at $12.57/share.

In another new development, Karotkin told Montali that PG&E will seek the judge's approval for its effort to modify its bankruptcy-exit financing plan, as announced in a filing with the U.S. Securities and Exchange Commission on Monday morning.

The effort involves issuing $3.25 billion in common stock at a below-market price of $10.50/share to a group of large investment funds and amending its equity-commitment backstop letters to allow financial institutions to buy stock, if needed, at a significantly lower price than the judge previously approved.

The stock market disruption caused by the COVID-19 crisis, and PG&E's lower-than-expected share price, made the changes necessary, Karotkin said.

Fire Victims Ask Judge to Reject PG&E Plan

In a hearing Thursday, fire victims unhappy with PG&E's reorganization scheme urged Montali to reject it, while others asked him to appoint an examiner to look into allegations of voting problems.

Two lawyers and an individual fire victim contended that many victims hadn't received ballots in time to vote on the reorganization plan by the May 15 deadline.

"The request for an appointment of an examiner is based on the very large amount of voting procedure irregularities that we've now seen," attorney Bonnie Kane said. "Primarily it appears from the problem of the fire victim creditors not receiving ballots or receiving them after the time in which they could vote."

Montali disputed the idea that there were a large number of irregularities.

Of the approximately 80,000 fire victims sent ballots, about 50,000 responded, voting by a large margin for PG&E's plan, Montali said. (See *PG&E Bankruptcy Moves Toward Conclusion*.) It isn't unusual for many people not to vote in bankruptcy cases, just as in presidential elections, he said.

"There are 50,000 people who voted, and by my count, less than 1,000 who may be, for whatever reason, in that category" of those who experienced voting difficulties, the judge said. "I don't consider that large in relation to the 50,000 who voted."

The vote by 88% of fire victims to approve the plan wasn't even close, he noted.

"This isn't a city council election," where the winner is decided by 15 votes, he said.

Montali gave more credence to fire victim Theresa Ann McDonald, who said she wanted to learn if voting problems occurred and why — just as she had wanted to know if PG&E started the Camp Fire, which burned down her home in Paradise, Calif., in November 2018.

The utility has acknowledged its equipment started the Camp Fire, the deadliest and most destructive in state history.

"Those are all pieces in putting the entire puzzle together," McDonald said.

She said Montali could appoint an examiner after approving PG&E's plan, allowing the bankruptcy case to move forward.

Karotkin contended even that could jeopardize the funding the company needs to emerge

CAISO/West News

from bankruptcy by casting a cloud of uncertainty over its plan.

"The debtors will be going out to the market to raise equity capital of $9 billion in the most efficient manner possible, and to have an overhang of a potential examiner here will impact the ability to effect that marketing effort on the best possible basis," Karotkin said.

After hearing all the arguments, Montali said he would rule on the matter later. He had not done so as of Monday.

'Exposed to Risks of Fire'

Later Thursday, fire victim William Abrams, a self-represented litigant in the case, urged Montali to reject PG&E's reorganization plan because, he said, it fails to ensure that a safe and financially stable utility emerges.

"This plan put together is not in good faith," Abrams said. "Its primary goal is to ensure that entrenched investors can cash out and exit the stock — to leave victims and the public living among the PG&E lines, exposed to risks of fire and risks associated with the fires that they cause." Abrams and his family had to flee their home in Santa Rosa, Calif., in October 2017, as the Tubbs Fire roared into Northern California city. State fire investigators said PG&E equipment didn't start the fire, but the company agreed to settle with Tubbs Fire victims as part of its restructuring.

Abrams repeated the argument that fire victims are the only large group of creditors being asked to accept PG&E stock as part of their settlement agreement. (See *Skeptics Get Last Chance to Sound off on PG&E Plan*.)

PG&E said it hopes to attract "traditional utility investors" after bankruptcy, but the utility won't pay dividends for years, he said.

The state and the California Public Utilities Commission will have to solve PG&E's safety and financial problems within months after it leaves bankruptcy, including by raising rates, he argued.

Jeremiah Hallisey, a lawyer representing other fire victims, called PG&E's plan a "house of cards" that is inherently unfair to victims.

Lawyers Start Arguments

Attorneys began debating the merits of PG&E's organization proposal Wednesday.

"I'm prepared to shut up and listen for your argument," Montali told the lawyers participating in the hearing via Zoom video.

Karotkin said PG&E's plan resulted from months of "hard-fought, good-faith" negotiations that led to agreements with all the major parties in the case, including creditors and fire victims.

"The plan before you today has the overwhelming support of the fire victims in addition, your honor, to the support of the governor's office [and the California Public Utilities Commission]," Karotkin told Montali. "All those approvals and support serve to ensure expedited distributions to fire victims, and that, your honor, is the principal goal that these debtors have expressed since these cases were commenced last January." (See *CPUC Approves PG&E Bankruptcy Plan*.) ■

A PG&E transmission line sparked the Camp Fire, killing 85 and destroying much of Paradise, Calif, on Nov. 8, 2018. | *USDA Forest Service/Tanner Hembree*

ERCOT News

IMM: ERCOT's Shortage Pricing 'Pivotal'

By Tom Kleckner

Shortage pricing played a crucial role in Texas wholesale market competitiveness last year, ERCOT's Independent Market Monitor said in its annual market *report*.

The report from Potomac Economics showed average real-time energy prices rose by 32% in 2019, despite a 23% reduction in natural gas prices. The Monitor attributed the increase to shortage pricing in August and September, when prices reached the offer cap of $9,000/MWh for more than two hours.

"Shortage pricing is key in ERCOT's energy-only market because it plays a pivotal role in facilitating long-term investment and retirement decisions," the Monitor said, the idea being that high prices during energy shortages will incent new generation.

ERCOT entered last summer with a reserve margin of 8.6%, which is up to 12.6% this summer. The Monitor said only 4.5% of the grid's generation was unavailable during summer peak conditions, similar to 2018 but lower than the 6% during 2016 and 2017.

"We attribute this increased availability to the effectiveness of the shortage price signals in motivating participants to increase maintenance and minimize outages during the summer peak," the Monitor said.

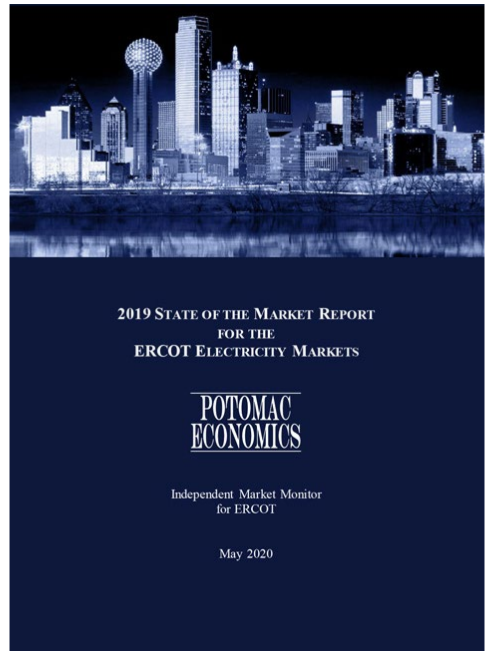
The Texas Public Utility Commission in January modified ERCOT's shortage pricing mechanism by altering the market's operating reserve demand curve. The changes accounted for a nearly $7/MWh increase in average energy prices and a $1.9 billion to $2.1 billion increase in energy revenue.

The PUC has also approved the real-time co-optimization of energy and ancillary services, scheduled to be added to the market in 2024.

"This will significantly improve the real-time coordination of ERCOT's resources, lower overall production costs and improve shortage pricing," the Monitor said. "These improvements will be increasingly valuable as additional intermittent wind and solar resources enter the ERCOT market."

In its report, the Monitor recommends key improvements to ERCOT's pricing and dispatch processes:

- Remove the "opt-out" option for resources receiving reliability unit commitment instructions.

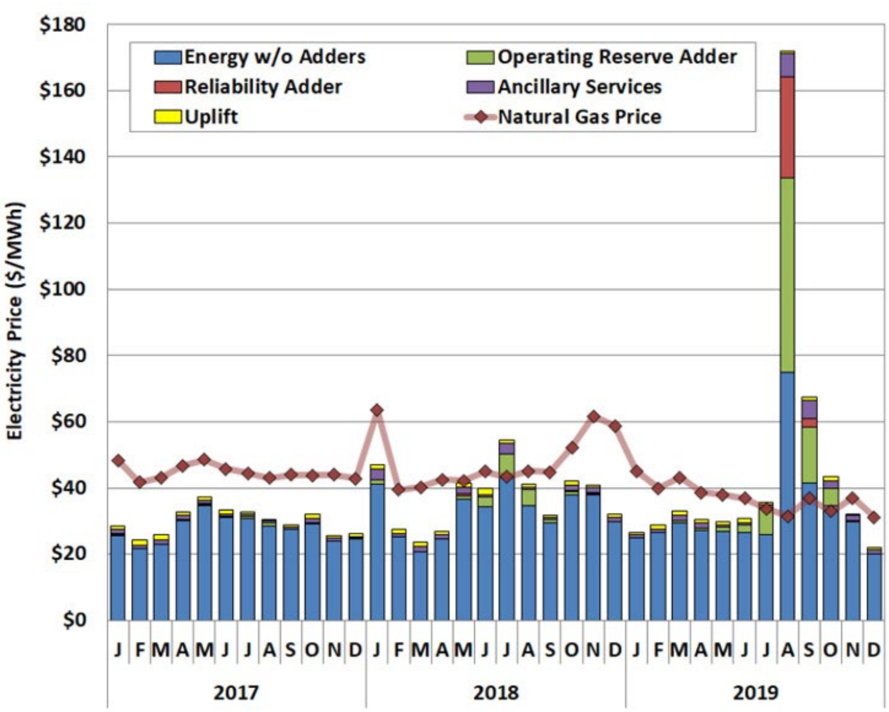


ERCOT's IMM has released its 2019 wholesale market report. | *ERCOT IMM*

- Eliminate the 2% shift factor rule, and price all congestion regardless of its generation effect.
- Modify the allocation of transmission costs by transitioning away from the four coincident peak (4CP) method.
- Price ancillary services based on the shadow price of procuring each service.
- Modify the reliability deployment adder and operating reserve adder to improve pricing during emergency response service deployments.
- Implement a locational reliability deployment price adder.
- Improve the mitigated offers for generating resources.
- Implement transmission demand curves.

The Monitor retired six other recommendations no longer needed, including the inclusion of marginal losses in ERCOT's LMPs. The PUC has concluded the incremental benefit of applying marginal losses was not worth the implementation cost and market disruption.

The market report was the first delivered under the guidance of Carrie Bivens, who promised a "timely and comprehensive" report when she was hired in April. (See *Bivens Steps in as New Director of ERCOT Monitor*.) ■



ERCOT's average all-in price for electricity highlights August spike. | *ERCOT IMM*

ERCOT News

ERCOT Briefs

Austin Energy to Retire 735 MW of Gas Units

Austin Energy has officially notified ERCOT that it plans to permanently retire one of the two original gas-fired steam units at its Decker Lake generating facility, effective Oct. 31. The municipal utility filed a notification of suspension of operations on June 1.

The 315-MW Decker 1 unit began commercial operation in 1971 and is the oldest generating unit in Austin Energy's fleet. Decker 2 went into service seven years later and has 420 MW of capacity.

According to the utility's latest *resource plan*, approved in late March by the Austin City Council, Decker 2 will be retired following the 2021 summer peak. An Austin Energy spokesperson said both units are nearing the end of their normal life expectancies.

Four other gas turbines at the facility, with a combined capacity of 192 MW, will continue to operate.

ERCOT has projected reserve margins of 17.3% and 19.7% in 2021 and 2022, respectively. Those figures include Decker 2's capacity.

2 Market Participants File Appeals with PUC

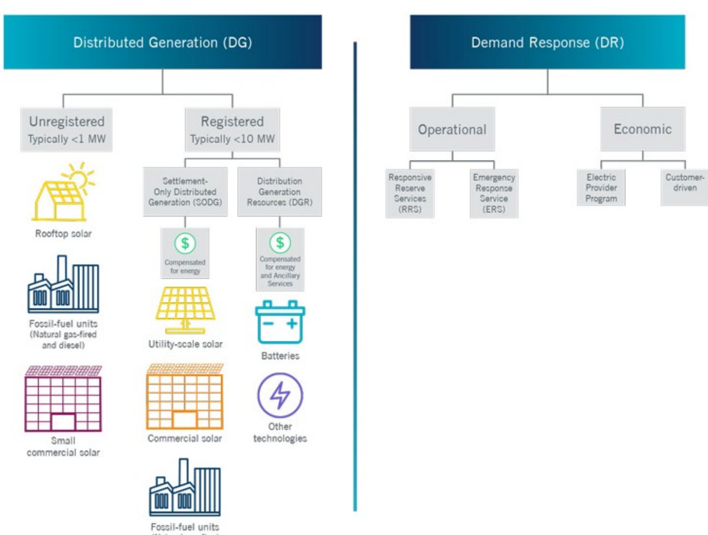
Two ERCOT market participants have filed appeals with the Public Utility Commission regarding last year's resettlement of 21 operating days, necessitated by a series of software errors.

Monterey TX, a qualified scheduling entity (QSE), *said* it is seeking "financial and injunctive relief" over what it says are "improper" charges for point-to-point (PTP) congestion revenue rights obligations in excess of its not-to-exceed bid prices in September 2019. Monterey is asking that the PUC direct ERCOT to halt its "unlawful behaviors" and is seeking more than $89,400 and accrued interest in compensation (*50881*).

Independent power marketer DC Energy *appealed* ERCOT's resettlement of certain PTP obligations at prices more than 1 cent/MWh above the company's not-to-exceed bid prices. DC Energy is seeking "redress of the economic penalty" it suffered from resettlement "that would put it in the same position economically" if ERCOT had honored the terms of its not-to-exceed bid prices when it resettled the day-ahead market (*50871*).

Both companies said they attempted to resolve their disputes with ERCOT, eventually submitting requests for alternative dispute resolution proceedings. Those requests were dismissed in April.

ERCOT's Board of Directors in December approved the price corrections for 21 operating days, dating back to September, after it determined that real-time prices were "significantly affected" by the software error. (See "Directors Approve Price Corrections for 21 Operating Days," *ERCOT Board of Directors Briefs: Dec. 10, 2019*.)



A slide from ERCOT's backgrounder on how DG and DR are used in the grid operator's footprint | *ERCOT*

ERCOT Adjusts to DG, DR Resources

ERCOT has published a *backgrounder* and an accompanying video on how distributed generation and demand response are used in its footprint. Both can be found on the grid operator's Distributed Generation *webpage*.

Staff have been working to catalogue the various forms of DG and DR in the region, primarily utility-scale solar, commercial solar and batteries. ERCOT only has 2 MW of operational DG but has another 374 MW in its interconnection queue.

"All generation resources provide great value to the grid, and our goal is to ensure these newer resources can participate in the ERCOT market and help provide reliable electric service to Texans," ERCOT Director of Grid Coordination Bill Blevins said in a *statement*.

ERCOT defines distributed generation as electrical generating facilities located at a customer's point of delivery, of 10 MW or less and connected at a voltage less than or equal to 60 kV, which may be connected in parallel operation to the utility system.

DG that intends to be dispatched by ERCOT or provide ancillary services must register as a DG resource and undergo qualification testing. DG with installed capacity of more than 1 MW and capable of providing a net export of energy into the distribution system is required to be registered as a settlement-only distribution generator.

TAC Passes Revised ERS Change

The Technical Advisory Committee on June 2 unanimously approved a change to how emergency response service resources return following recall.

The Nodal Protocol revision request (*NPRR1006*) returns ERS resources in a linear curve over a four-and-a-half-hour period following recall, instead of 10 hours. It also changes the process for annually updating the parameter so that the TAC does not have to file an NPRR.

The vote was conducted by email after a previous version was rejected on May 27 in a similar email vote. Direct Energy offered revisions that removed a real-time deployment price adder from the original language. (See "Members Disagree over Change to ERS' Return," *ERCOT Technical Advisory Committee Briefs: May 27, 2020*.)

NPRR1006 passed by a 26-0 margin and now goes before the board during its June 9 teleconference. The measure failed 4-20, with two abstentions, the week before.

NPRR1066's implementation is expected to cost between $140,000 and $180,000 and take up to nine months. ■

— Tom Kleckner

ISO-NE News

NEPOOL Participants Committee Briefs

Energy Market Revenues Hit 17-year Low

ISO-NE's energy transactions rang in at $159 million in April, the lowest monthly total since 2003, as the COVID-19 pandemic and ensuing shutdown of most economic activity continued to weigh on New England's energy market.

"I wouldn't be surprised if May breaks April's record in terms of the lowest energy market value over the last 17 years," COO Vamsi Chadalavada *reported* to the New England Power Pool Participants Committee on Thursday. His report covered data through May 27, which showed a month-to-date energy market value of about $120 million.

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

May 2020 natural gas prices over the period were 16% lower than April average values and down 41% from a year ago. Average real-time hub LMPs ($16.39/MWh) were 9.4% lower than April averages and down 28% from May 2019 averages.

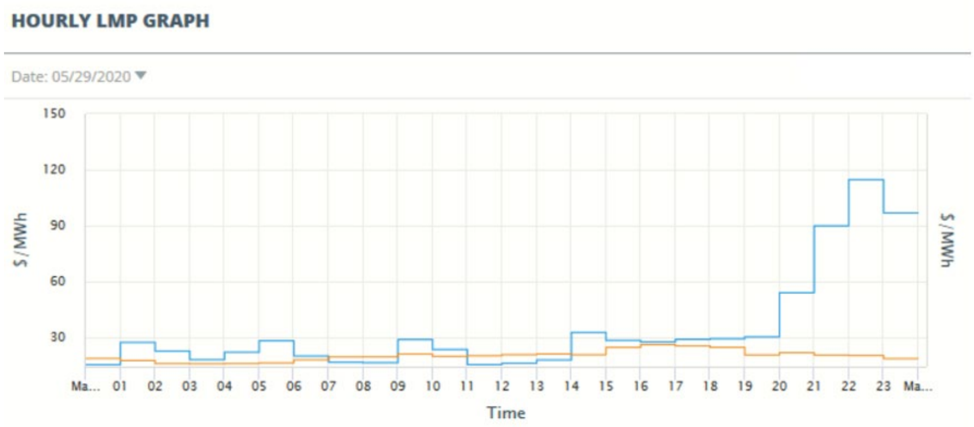
The RTO still has approximately 95% of its workforce working remotely and will continue that "remote deployment posture" until June 15, when it expects to start its re-entry plan, Chadalavada said.

"We are comfortable that we are compliant with the guidelines issued by [the Centers for Disease Control and Prevention], the states of Massachusetts and Connecticut, and also the local authorities," he said.

Boston RFP and System Disturbances

ISO-NE's competitive transmission solicitation for Boston garnered 36 proposals from eight qualified parties by the March 4 deadline, Chadalavada said, adding that the RTO would present a draft list of qualifying Phase One proposals at the June 17 Planning Advisory Committee meeting. (See "*Faster Boston RFP," NEPOOL Participants Committee Briefs: May 7, 2020*.) (In an unexpected development Monday, the RTO announced that it had selected only the cheapest of the proposals for a second round of review, a $49 million plan from incumbents National Grid and Eversource Energy. See related story, *National Grid, Eversource Finalist for Boston Tx Plan*.)

A markedly quiet month in terms of operations turned less so in the last week of May with system disturbances on May 27 and 29, Chadalavada said.



Real-time LMPs (blue line) spiked May 29 when a control rod malfunction at the Seabrook nuclear plant in New Hampshire took 1,340 MW off the grid. Day-ahead prices are shown in orange. | *ISO-NE*

On May 27 at 2:48 p.m., the system experienced the loss of the Phase II transmission line to a lightning strike, resulting in the loss of 1,980 MW, "a fairly severe source loss, given the size of New England," he said.

May 29 brought two events, Chadalavada said: "We lost a major generation facility at [2:04 p.m.], which was about 1,250 MW, and later that evening, we lost the first pole at Phase II at 8:23 p.m. and the second one at 8:34 that night, again due to equipment failure."

According to a *report* from New Hampshire Public Radio, the evening event stemmed from a control rod malfunction at the Seabrook nuclear plant, with the subsequent scram taking 1,340 MW off the grid.

The total loss was about 2,600 MW, "so on a 14,000- to 15,000-MW load, that translates to north of 20% of energy loss that had to be replenished," Chadalavada said.

All transmission and disturbance control standard criteria were met and maintained during and after the events, he said.

Virus Reduces RTO Spending

The financial impact of the COVID-19 pandemic will likely translate into net savings in ISO-NE's 2020 budget, said Chief Financial and Compliance Officer Robert Ludlow in presenting the preliminary 2021 and 2022 operating and capital budgets.

Committed COVID-19 spending totals $730,000, with current projected possible risks of an additional $300,000, but offsetting those increased costs are $800,000 in planned costs that will not be incurred in 2020. Those savings are primarily derived from suspended travel and training and the limited hiring of interns this year.

ISO-NE Tariff collections for January through April were lower by 5.7% (or $3.6 million), reflecting decreased load, which is estimated to be 3 to 5% lower because of the pandemic.

The 2021 and 2022 budgets' year-over-year increases before depreciation are projected to be $4.8 million (2.7%) and $6.3 million (3.5%), respectively.

The proposed budgets will be presented in August with a detailed review of project budgets and estimated go-live dates.

Order 1000 Questions on Tx Planning

The PC 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, as recommended by the Reliability Committee in May. (See "Changes to PP10 for Tx Solution," *NEPOOL Reliability Committee Briefs: May 19, 2020*.)

The motion passed with 99.12% in favor.

Exelon argued in a presentation that ISO-NE is abandoning planning principles for expediency and thereby risking reliability.

"The proposed amendment to Planning Procedure 10 appears to be a result-driven attempt to preclude the potential retention of Mystic 8 and 9 for transmission security; the amendment and its attendant consequences, however, will live long after Mystic 8 and 9

ISO-NE News

have retired," Exelon said in its presentation. (See *Exelon Bid to Keep Mystic Units Running Provokes Outrage*.)

"A significant amount of information is provided to the ISO early in the solicitation process, including information necessary for the ISO to determine whether the reliability need can be satisfied with the proposal," said ISO-NE Director of Transmission Services and Resource Qualification Al McBride.

The changes are intended to prevent unnecessarily retaining a resource for reliability if transmission responses in the competitive solicitation process address the reliability need, McBride said.

Consent Agenda

The PC on its consent agenda approved a revision to Operating Procedure 12 (*OP-12*) related to voltage and reactive control, as recommended by the RC in May.

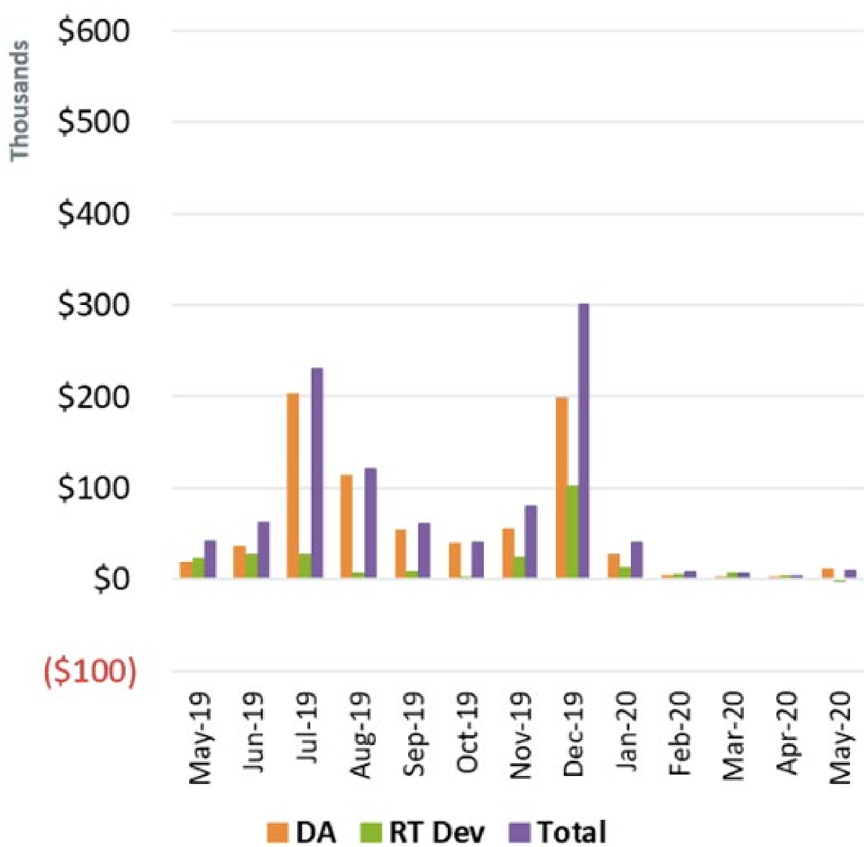
The changes:

- reflect the source of the data in OP-12B (voltage and reactive schedules);
- explain the different categories of voltage control for generators;
- clarify the use of "On Peak Period" and "Off Peak Period";
- add that OP-12B would be updated "as needed"; and
- specify that ISO-NE may request technical status for certain units that have operational impact.

The committee also approved revisions to Market Rule 1 and Manual M-11 to modify the day-ahead energy market offer window, as well as clean-up changes to the offer cap, as recommended by the Markets Committee last month.

The submission deadline for day-ahead offers and bids moves from 10 to 10:30 a.m.; the offer cap filing revisions were approved by FERC (ER17-1565).

The PC also voted to approve a FERC filing to address rejected portions of ISO-NE's Order 845 compliance filing (ER19-1951), as recommended by the Transmission Committee in May following the commission's May 19 *rejection* of the RTO's request for clarification on the issue. (See *NEPOOL Transmission Committee Briefs: May 27, 2020*.) The commission issued Order 845 in 2018 to set *pro forma* minimum standards for large generator interconnection procedures and agreements.



Data through May 27 indicate the full month will likely surpass April's record for the lowest energy market value in New England since 2003. | *ISO-NE*

The PC deferred voting on major changes to the RTO's billing policy until fall, with some related clean-up changes to the ISO-NE Financial Assurance Policy to be voted sooner at the virtual summer meeting June 23.

The committee also considered in executive session and unanimously approved — with some abstentions — ISO-NE Tariff revisions to carry out the settlement agreed to among New England Transmission Owners (NETOs), FERC staff and municipally owned power companies on pool transmission formula rates (EL16-19).

Litigation Report

The monthly litigation report mentioned that FERC will hold a technical conference July 8-9 to explore the potential longer-term impacts of the emergency conditions caused by COVID-19 on FERC-jurisdictional entities (AD20-17).

In addition, the commission issued a supplemental notice waiving through Sept. 1 its regulations that require filings with FERC be notarized or supported by sworn declarations (AD20-11).

Another item noted that FERC in May approved a procedure for "critical" New England generators and transmission operators to obtain compensation for compliance with NERC rules regarding interconnection-reliability operating limits (IROL) (ER20-739). (See *FERC OKs Payment Rules for IROL Facilities*.)

"Regarding the IROL, we were disappointed to see that," said Brett Kruse of Calpine. "We do think ISO New England in this case acted in good faith, and we appreciate what they tried to do. This has ramifications. The next time the ISO comes to us and says, 'We need you to start spending money on x, y or z because it's a reliability issue,' the first thing we're going to have to think about, instead of going out and immediately doing it like we did this time, is go get it in front of FERC and get them to approve it. If that takes two and a half years, as it did in this case, well that's what it takes."

In addition, the litigation report noted that several market participants and state entities had filed comments and protests on the separate Energy Security Improvements filings submitted by ISO-NE and NEPOOL (ER20-1567). (See *ISO-NE Sending 2 Energy Security Plans to FERC*.) ■

— Michael Kuser

ISO-NE News

National Grid, Eversource Project Finalist for Boston Tx Plan

Incumbents Selected for RTO's First Competitive Project

Continued from page 1

ISO-NE's presentation for the PAC meeting, also *posted* Monday, detailed how planners narrowed the field to BOS-017. The RTO did not identify any of the bidders in its announcement or the presentation, saying it identified the projects by randomly assigned unique IDs to "eliminate bias."

BOS-017 includes the installation of two 11.9-ohm, 345-kV series reactors at the North Cambridge substation (one each on the two 345-kV Woburn-to-North Cambridge cables); a +/-167-MVAR STATCOM at the 345-kV Tewksbury substation; and a direct transfer trip scheme on the 394 line to eliminate the contingency that causes the 115-kV K-163 line overload.

Mystic Retirement

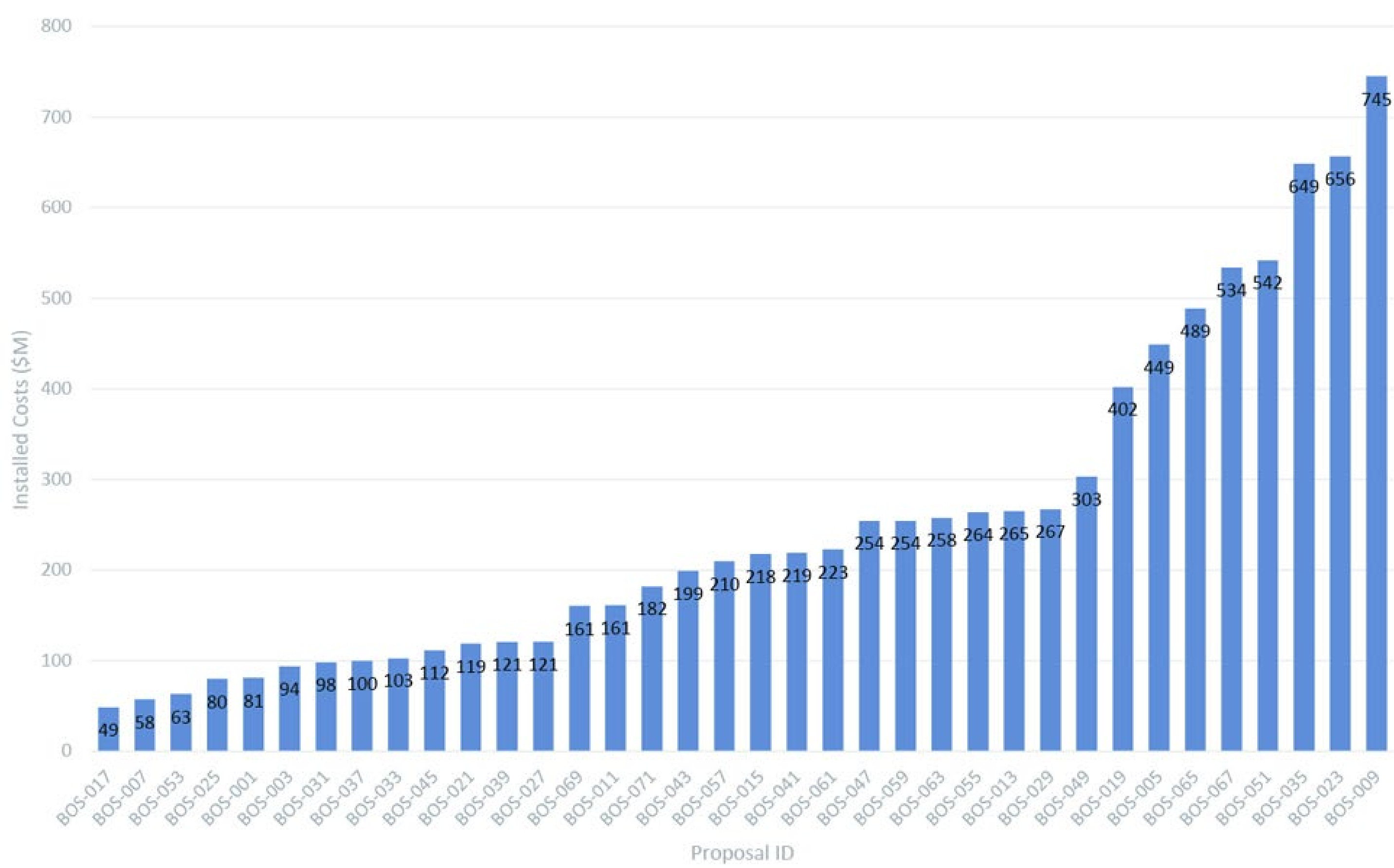
The project has an in-service date of Oct. 1, 2023. The key in-service date for the RFP is June 1, 2024, the day after the planned retirement of the Mystic Generating Station. The RTO said Mystic's retirement would result in one N-1 115-kV line overload and three N-1-1 345-kV line overloads. It also identified the need for a +/-150-MVAR dynamic reactive device (DRD) based on system restoration needs.

National Grid and Eversource said their most cost-effective solution maximizes the use of existing transmission facilities and keeps upgrades entirely on their rights of way, minimizing the environmental impact. It would be in-service eight months prior to the planned Mystic retirement.

One market participant, speaking not for attribution, said the move by the RTO to reject all of the other proposals was "almost guaranteed" to result in litigation by some of the other seven qualified transmission project sponsors that had submitted proposals.

ISO-NE's announcement came three days after it had received a letter from Massachusetts' two U.S. senators urging the RTO to "prioritize the effects that projects may have on state climate, energy and health goals" when evaluating the Boston RFP proposals. (See related story, *Mass. Senators to ISO-NE: Think Clean on Boston RFP*.)

In their letter, Sens. Ed Markey and Elizabeth



ISO-NE, which received 36 proposals ranging as high as $745 million to upgrade the Boston area's transmission system, selected the cheapest plan — a $49 million project that includes two 345-kV series reactors. | *ISO-NE*

ISO-NE News

Warren, both Democrats, criticized the RTO's planning process for listing "environmental impact" in the lowest priority category for the evaluation and noted that "public health impacts are not called out at all."

Priority

In its presentation, ISO-NE said it had "repeatedly stated that the two most important evaluation factors for the Boston 2028 RFP are 'cost and speed.'"

"This point was emphasized by the following statement: 'consideration of all evaluation factors, especially those in groups of lower importance, may not be necessary to make this determination.'"

The 36 projects had in-service dates ranging from March 2023 to December 2026.

The RTO said that most of the Phase One proposals were excluded as a result of the preliminary review because of one or both of the following:

- The proposal did not address the identified needs.
- The proposal failed to meet the Tariff or RFP instructions.

Ultimately, five proposals addressed the needs for a reliable power system and met all other requirements, ISO-NE said. The RTO compared these projects' costs, which ranged from $49 million to $121 million.

"Given that the $49 million project is significantly less expensive (the next least expensive proposal is for $94 million), the ISO is recommending that the other four projects not advance to the second phase of review, as it is unlikely that further review would lead to their selection," the RTO said. "Development costs incurred during the second phase of review are charged to ratepayers, so not advancing projects that are unlikely to be selected is a savings for ratepayers."

Based on their initial review, ISO-NE said it and its consultants concluded BOS-017 solved the identified needs; had a reasonable cost estimate; did not require transmission line siting or acquisition of real estate; requires "limited" permitting; and its in-service date of October 2023 is "reasonably achievable."

The RTO will accept comments on the draft listing of qualifying Phase One proposals until July 2 at *pacmatters@iso-ne.com*.

Life-cycle Costs

The RTO said life-cycle costs were not considered in determining the competitiveness of the proposals because they "can be misleading."

"The total life-cycle cost, which includes PTO [participating transmission owner] upgrades for the existing system, is not known until the Phase Two solution process," it said.

"Where a significant number of upgrades to the existing system have been included as part of the Phase One proposal, the delta between the provided life-cycle cost and the expected life-cycle cost can be hundreds of millions of dollars," it added.

During the March 2020 PAC meeting, several stakeholders raised questions about the RFP review procedures. (See "Procedural Questions on Tx RFP," *ISO-NE Planning Advisory Committee: March 18, 2020*.)

Phelps Turner, a senior attorney for the Conservation Law Foundation in Maine, flagged due process concerns with the proposed schedule, saying it should be expedited to ensure openness and transparency.

One market participant, speaking not for attribution, said the move by the RTO to reject all of the other proposals was "almost guaranteed" to result in litigation by some of the other seven qualified transmission project sponsors that had submitted proposals.

The planning principles are clearly outlined in FERC Order 1000, Turner said, adding that "we also want to make sure we set a good precedent with this first competitive procurement [in New England]." Turner told *RTO Insider* that CLF was concerned about the evaluation process for all proposals, not just for any single bid. ■

ISO-NE News

Mass. Senators to ISO-NE: Think Clean on Boston RFP

By Michael Kuser

Massachusetts' two U.S. senators on Friday urged ISO-NE to prioritize "state climate, energy and health goals" when evaluating responses to a request for proposals seeking transmission projects to address the 2024 retirement of the Mystic Generating Station near Boston.

Sens. Ed Markey and Elizabeth Warren, both Democrats, sent a *letter* criticizing the RTO's Boston 2028 RFP planning process for listing "environmental impact" in the lowest priority category for evaluation, noting that "public health impacts are not called out at all."

"In particular, the eventual retirement of this power plant, which is the largest fossil fuel plant in New England, presents an opportunity to continue cleaning up the New England power grid and safeguarding public health," they said. "The six New England states have all committed to achieving at least a 75% reduction in their greenhouse gas emissions by 2050. The Carbon Free Boston initiative aims to reach a target of carbon neutrality for the city by 2050. As part of the Boston 2028 RFP, ISO-NE should consider and prioritize these targets."

ISO-NE spokesman Matthew Kakley declined to comment Friday, saying the RTO had just received the letter and was still reviewing it.

The RTO received 36 phase one proposals in response to the request, with costs ranging from about $49 million to $745 million, and in-service dates ranging roughly from mid-2023 to 2026.

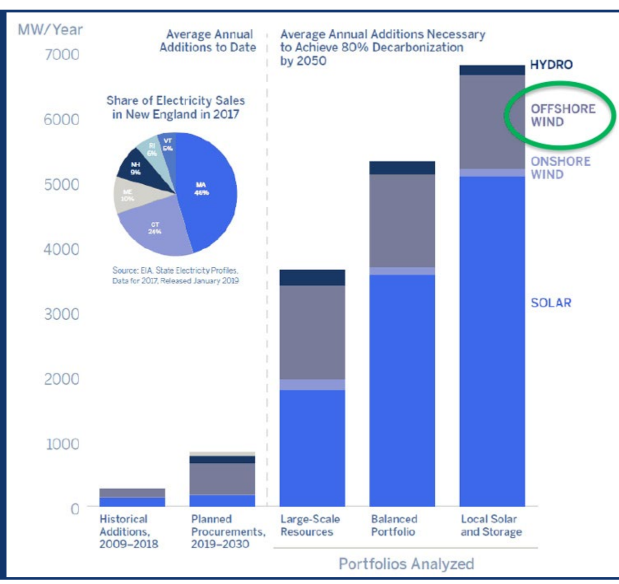
The RTO's transmission planners will share their draft list of qualifying proposals at a Planning Advisory Committee meeting June 17.

Both Markey and Warren last November joined five of their fellow New England senators in sending a letter to the RTO accusing it of "preserving the status quo of a fossil fuel-centered resource mix" in its fuel security planning triggered by the Mystic retirement. (See *Senators Ask ISO-NE to Heed States on Clean Energy*.)

Side Pressure

"As Massachusetts and other New England states work to reach decarbonization targets and respond to the ongoing COVID-19 pandemic, it is more important than ever that regional transmission organizations consider these impacts as part of electric-grid planning," the senators said.

Eight qualified transmission project sponsors submitted bids for the Boston RFP. Among them was Anbaric Development Partners, which in March announced *details* of its proposed 900- to 1,200-MW Mystic Reliability Wind Link transmission project, including an option for an additional 1,200 MW of transmission capacity. (See *ISO-NE Planning Advisory Committee: March 18, 2020*.)



New England likely needs 1,500 MW+ of new offshore wind resources every year to achieve 80%-by-2050 decarbonization goals. | *The Brattle Group*

"Additionally, as Massachusetts and other New England states continue efforts to limit and stop the spread of COVID-19, it is important to consider the public health effects of various kinds of electricity generation," the senators said. "Research continues to show a link between air pollution and higher COVID-19 death rates, placing a premium on regional transmission organizations' factoring air quality into their grid-planning decisions — particularly for communities that are disproportionately affected by COVID-19 and the historic burden of air pollution."

Last June, about 300 people turned out in Springfield, Mass., to attend a Department of Energy Resources hearing on a proposal to alter the state's renewable portfolio standard to include biomass plants. (See *Residents Protest Biomass at Mass. DOER Hearing*.)

Among the nearly 60 people testifying were a dozen biomass industry proponents and five members of the Springfield City Council opposing plans by Palmer Renewable Energy for a 35-MW wood-burning plant in East Springfield.

"Clean energy and clean air are both important policy objectives for Massachusetts and the broader New England region, and those priorities should be reflected appropriately among the evaluation criteria for the Boston 2028 RFP," the senators said.

Last August, about 40 environmental activists marched in front of the headquarters of Connecticut's Department of Energy and Environmental Protection to protest state regulators' approval of a new gas-fired power plant in the town of Killingly. (See *Connecticut Activists Protest Gas-fired Plant*.)

The Connecticut Siting Council last June approved construction of the 650-MW Killingly Energy Center by Florida-based developer NTE Energy, permitting the plant to emit up to 2.2 million tons of carbon dioxide each year.

"Fossil fuel plants are increasingly uneconomic, particularly as the cost for new renewable electricity generation declines, and after factoring in the costs to public health from air pollution," the senators said. "In pursuing transmission solutions to meet electricity demand and address reliability needs, ISO-NE can also strive to better integrate low- or no-carbon generation projects, with the added benefit of saving ratepayers money and avoiding the need to bail out uneconomic plants." ■

MISO News

MISO Stakeholders Split on Seasonal RA Measures

By Amanda Durish Cook

Stakeholders are divided over whether MISO has conducted enough analysis to justify the possible adoption of seasonal capacity auctions and loss-of-load expectation (LOLE) studies.

The mixed opinions arose during a June 1 virtual workshop to discuss the next steps in MISO's resource availability and need (RAN) project. In addition to a possible seasonal LOLE study and capacity auction, the RTO is also considering whether to use the RAN effort to define its own set of reliability requirements and design scarcity pricing that better reflects tight supply.

If it opts for any of those solutions, MISO hopes to make FERC filings in the middle of next year in order to introduce changes by early 2022.

"We're on a pretty aggressive timeline, and one that needs your input," MISO Director of Resource Adequacy Coordination Zakaria Joundi told stakeholders.

The RTO is currently drafting a white paper on the problem statement behind the next round of proposed RAN fixes. But some stakeholders argue that the RTO doesn't need another self-published white paper; rather, it needs to solicit and include stakeholders' input.

Madison Gas and Electric's Megan Wisersky took issue with MISO consistently using the word "enhancement" in RAN solutions.

"You keep saying you're making 'enhancements.' What you're actually doing is reducing capacity accreditation. So it really doesn't feel like 'enhancement.' It feels like private property is getting devalued over and over again," Wisersky said, taking aim at a RAN proposal to cut the capacity credits of load-modifying resources based on lead times and availability. (See *MISO Delays New LMR Accreditation Launch*.)

"We're seeing the risk move away from the summer peak," Joundi said. "The current annual construct does not reflect a changing risk profile and evolving resource needs."

More Analysis?

Customized Energy Solutions' David Sapper asked for more analysis to prove that MISO really does face reliability risks outside of a summer peak.

WPPI Energy's Steve Leovy said that while he believes there is probably a loss-of-load risk in September, he doesn't believe MISO has demonstrated a material risk outside of summer until it prepares a full LOLE analysis on par with those prepared for the Planning Resource Auction.

"That leaves a very real prospect that we could launch into a seasonal PRA ... and it could just be a waste of everyone's effort if you don't have material risk outside of summer. There's not been a showing that the annual construct is inadequate. If we see it, we'll shut our mouths, but we don't see it," Leovy said.

"MISO staff points to conclusions. MISO staff says, 'OK, we've had emergencies outside of summer months, but there's nothing more than that to prove we have a problem in the off-peak season,'" the Coalition of MISO Transmission Customers' Kevin Murray said.

Minnesota Public Utilities Commission staff member Hwikwon Ham argued that MISO's changing risk profile is clear in its renewable integration impact assessments, but he too pressed for a full LOLE study that could show risk beyond summer.

"I think we have an issue, but that issue isn't properly translated into the LOLE study," he said.

Ham also told MISO staff that it's time to design a long-term solution and put an end to its incremental RAN solutions that focus on generator outage scheduling and LMR availability.

Consumers Energy's Kevin Van Oirschot countered that incremental solutions pose the least risk of damage to the market.

Other stakeholders said MISO's increasingly common maximum generation emergencies are justification enough for a seasonal parsing of reliability risks or capacity.

"Xcel Energy is ready to move forward," Kari Hassler said of her company. "We believed that the current construct worked well ... but times are changing; resources mixes are changing; operations are changing. The matching up of seasonal variations makes sense. We don't need any more studies. We've been dragging this out for a year-and-a-half; we're ready to move forward."

Hassler argued that an LOLE study in search of non-summer risk has to be done "for the future, not for yesterday." She said data used in such an analysis should be forward-looking, not historical. Multiple stakeholders said forward-looking data should include planned resources in the interconnection queue.

"We need to look at the future years rather than saying, 'You need to show us evidence that relies on historical data.' I think that's the wrong argument," Ham agreed.

"Even if we don't have non-summer risk, we think there's value in a seasonal construct. The seasonal capabilities of our resources are dramatically different," WEC Energy Group's Chris Plante said.

Gabel Associates' Travis Stewart argued that MISO's three dozen maximum generation emergency events and warnings since 2016 are justification enough for change.

"Such a frequency of emergency events doesn't occur in any other RTO," he said. "The time is ripe for change."

Stewart said MISO should examine all capacity resource accreditations, not just LMRs.

MISO Executive Director of Market Strategy and Design Scott Wright said that the capacity the PRA clears and "what actually shows up" are two different things.

The RTO has said its current capacity accreditation processes don't match up with actual capacity resource availability, don't reflect resource availability in months outside of summer and don't account for operational differences between capacity resources.

Multiple stakeholders on the call asked that MISO create reliability requirements before it begins tinkering further with capacity resource accreditation. Many worried aloud that the RTO might penalize necessary planned generation outages.

"Just saying, 'Why aren't you there?' is short-sighted. There are legitimate reasons to be unavailable," Northern Indiana Public Service Co.'s Bill SeDoris said.

Wright thanked stakeholders for their frankness during the workshop and said MISO staff will consider comments when making RAN proposals.

"We didn't want to have 25 slides and have MISO speak. We wanted to hear you," Wright said of the workshop format.

The RTO plans to hold more RAN workshops with stakeholders before settling on which future filings it may pursue. ■

MISO News

Heat Counteracts COVID-19 Impact on MISO Load

By Amanda Durish Cook

Unseasonably warm weather has nudged MISO load a little closer to normal last week, though RTO officials say demand is still being compressed by pandemic-related social distancing measures.

A heat wave pushed MISO's peak load to nearly 100 GW, compared with peaks of about 73.5 GW in April and May.

"Our peak has been around 75 GW, and since we've seen warmer temperatures, our load jumped up 25,000 MW to about 100 GW, so things have been changing quickly," MISO Executive Director of Real-Time Operations Rob Benbow said during a Reliability Subcommittee meeting Thursday.

Last June saw a peak of 107.8 GW late in the month, with loads averaging 77.8 GW, far below the 84.5-GW average in June 2018.

But Benbow said MISO load has not quite returned to normal.

"I think we're still seeing some impacts of COVID on our load right now," Benbow said.

MISO predicts a 125-GW summer peak, with 152 GW of capacity on hand to cover it before generation outages are factored in.

Director of Balancing and Interchange Operations Tag Short said MISO will probably have to declare an emergency this summer to access load-modifying resources to mitigate tight supply. (See *MISO Preps for Balmy Summer with Pandemic Effects*.)

"And, oh by the way, NOAA is forecasting a warmer-than-average summer for the entire footprint. Seems like that happens every year," Short reported.

But Short said MISO's summertime load predictions, first presented in April, don't consider the pandemic continuing to shave some megawatts off load through the season. At last count, load was *trending* about 10% below average in May.

"Today, systemwide demand is slightly down because of the pandemic. In the case that energy usage does remain low, it may get us through July and August without a maximum generation alert," Short said.

Some stakeholders chafed at MISO not factoring in the pandemic in its summer readiness presentations.

"When MISO makes these very public declarations, it has consequences. My executive is going to come to me asking for our preparations; my regulator is going to come to me asking for our plans. If this is really nothing more than Chicken Little saying, 'the sky is falling,' then it's going to waste a lot of time," Consumers Energy's Kevin Van Oirschot said.

MISO also began to gradually phase in the return of its employees to work on June 1, Benbow said, allowing some non-operator positions to work on-site in its buildings on a voluntary basis.

Benbow said employees that wish to return must first answer screening questions via a phone app that instructs them on whether entering the office is advisable.

Employees must don a mask whenever they're not at their personal workstations, Benbow said.

"We have seen a dozen people really come and go throughout the week. We didn't expect a lot of people to return, and we're still encouraging people to work from home," Benbow said.

RSC Chair Bill SeDoris, of Northern Indiana Public Service Co., said his company has rolled out similar measures.

"It seems like this is going to be a common practice going forward for the foreseeable future," SeDoris said.

Benbow said the mask mandate has become a common practice among other RTOs/ISOs.

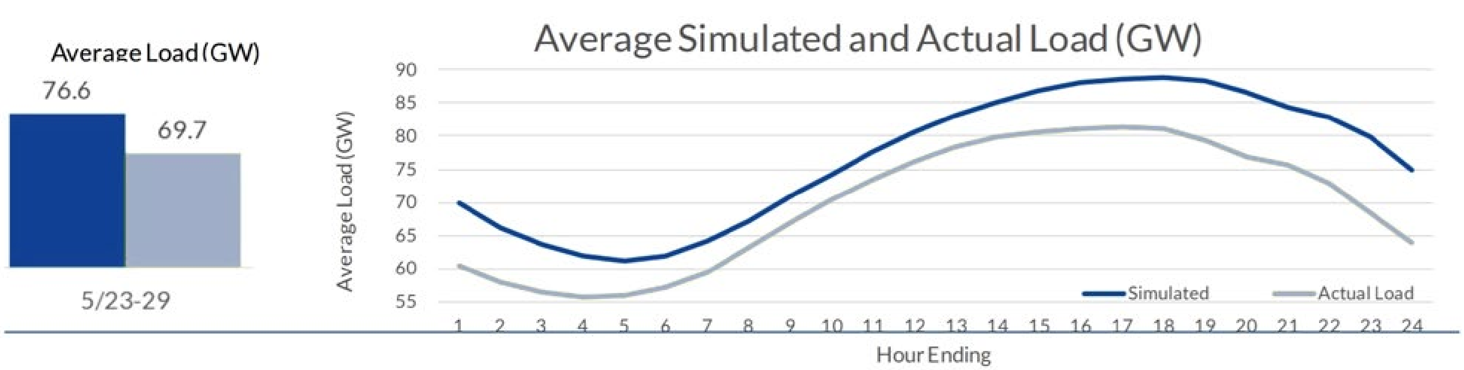
COVID-19 testing for MISO control room operators is still being done locally with local health care providers, Benbow said, and not through any U.S. Department of Energy program. He added that not a single MISO operator has tested positive for the coronavirus to date.

MISO in May also conducted two hurricane drills with members, operating training team lead Jay Hermacinski said. He added that MISO redesigned its drills this year from the usual eight hours to four hours, as most drill responders worked from home.

The RTO will conduct two power system restoration drills in October, Hermacinski said, and it is devising two separate drill formats in case the pandemic continues into fall and operators aren't allowed to congregate in training rooms.

Hermacinski said "conversations are being had" about how to make the drills effective if they're conducted remotely.

Meanwhile, some of MISO's interconnection queue customers now have more time to secure proof of land use for their generation projects. FERC last month granted MISO's request for a 60-day extension of its June 25 site control demonstration deadline as the pandemic slowed construction and shuttered government offices (*ER20-1794*). (See *Wary of Contagion, MISO Bars Visitors for 2020*.) ■



MISO simulated average load compared to actual load May 23-29 | *MISO*

MISO News

$10M Deal Reached over MISO, PJM Pseudo-tie Fees

Five generators have struck a $10 million settlement with MISO and PJM over the RTOs' past practice of double-charging pseudo-tied generation for congestion fees.

Under the *settlement* approved May 29 by FERC, the RTOs will refund a combined $10.3 million to five pseudo-tied generators. MISO will pay a total of $8.47 million, while PJM will pay $1.83 million (*ER20-1342*).

Tilton Energy lodged a complaint in 2016 against the RTOs for assessing overlapping congestion charges on pseudo-tied resources. American Municipal Power, Northern Illinois Municipal Power Agency, Dynegy and Illinois Power Marketing soon followed with similar complaints. FERC consolidated the proceedings, and the commission ordered a refund hearing in the matter last May. (See *Refund Hearing Ordered in Pseudo-Tie Complaint*.)

The RTOs introduced a temporary rebate program in 2017, then began including pseudo-ties in the day-ahead scheduling process in 2018 to end redundant congestion costs.

| © RTO Insider

Dynegy will receive the largest refund, with almost $5.3 million from MISO and $1.1 million from PJM. American Municipal Power will receive the second highest with $1.9 million from MISO and a little more than $412,000 from PJM.

The three other generators' refunds are well under $1 million apiece:

- Northern Illinois Municipal Power Agency stands to receive $620,193 from MISO and $133,997 from PJM;
- Illinois Municipal Electric Agency will receive $493,398 from MISO and $106,602 from PJM; and
- Tilton Energy will be refunded $161,177 from MISO and $34,823 from PJM.

FERC said the settlement was fair, in the public interest and resolved all the pseudo-tied congestion fee disputes that it set for hearing last year. ■

— Amanda Durish Cook

MISO News

MISO West Planning Belies Upgrade Needs, Critics say

By Amanda Durish Cook

MISO West won't be the site of pricey build-outs in this year's transmission planning cycle, despite complaints from critics that renewables in the region's interconnection queue necessitate billions in grid upgrades.

"We don't have any super big-ticket projects for the West this year," MISO Manager of Expansion Planning Zheng Zhou said at a June 2 subregional planning conference call for the region, which includes Minnesota, Iowa, parts of the Dakotas and western Wisconsin.

Transmission owners in MISO West proposed 145 new projects for about $910 million in the 2020 Transmission Expansion Plan (MTEP 20), which so far contains 510 proposed projects at a combined $4.06 billion.

The costliest is American Transmission Co.'s $40 million Arcadian power transformer upgrade project in southeast Wisconsin, proposed because of the age and condition of the existing equipment.

But no projects in the West region were among the top 10 most expensive, currently found in MISO's Central and South regions. (See *Price Tag Rising for MTEP 20*.)

At the same time, the West region is showing the need for billions in transmission investment to accommodate new generation projects, based on the makeup of MISO's interconnection queue.

The April 2018 cycle of 35 projects at 4.7 GW *shows* the need for a total $1.1 billion in network upgrades, before affected-system network upgrades are factored in. The August 2017 cycle of about 4.1 GW in 27 projects also needs about $1.1 billion in transmission upgrades.

Stakeholders have argued that MISO West is neglected in terms of new transmission capacity, which they say has led to prohibitively expensive network upgrades and stifled proposed renewable generation projects.

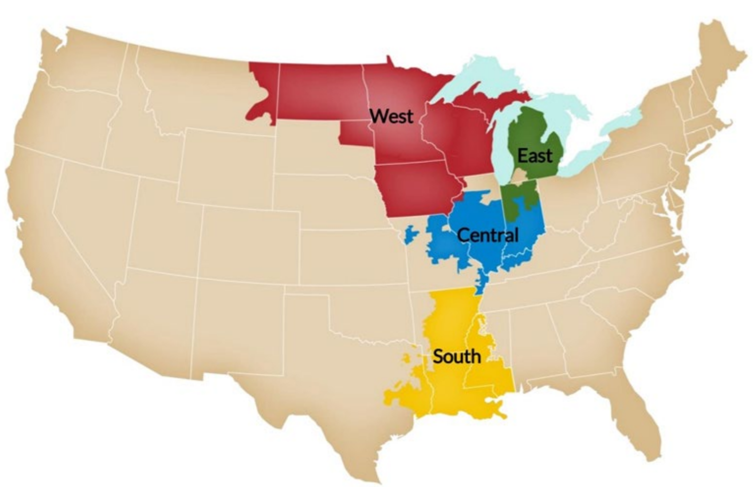
MISO is currently processing six cycles of West interconnection requests dating to 2017. The interconnection queue currently *contains* 434 projects totaling 67.4 GW, enough capacity to cover a little more than half of MISO's peak load. More than 60 generation projects have dropped out of the queue so far this year, while about 30 have completed generator interconnection agreements.

Revealing Overlap

MISO also announced it has identified 313 reliability issues in need of solutions in the West service areas of Northern States Power, Central Minnesota Municipal Power Agency, Minnesota Municipal Power Agency, Minnesota Power, Otter Tail Power and Minnkota Power Cooperative.

Most of those reliability issues are not covered by proposals submitted for MTEP 20. MISO said it will continue assessing the likelihood for contingencies and announce any additional transmission needs during the next West subregional planning meeting in August.

The RTO has pledged to address the increasing cost of network upgrades in its interconnection queue by linking its annual transmission planning process with network upgrade planning. The synchronization could result in MISO approving more transmission projects; however, those changes will begin with MTEP 21, not MTEP 20. (See *MISO Floats Ideas on MTEP, Interconnection Coupling*.)



MISO planning regions | *MISO*

Zhou said MISO cannot yet confidently select a project that handles overlapping economic, reliability and generator interconnection needs because so many proposed generation projects drop out of the queue.

Clean Grid Alliance's Natalie McIntire said she understands MISO doesn't have a process in place for combining reliability, economic and network upgrade projects, but she asked the RTO to be more forthcoming about projects that could potentially be merged.

"Maybe we can be a little more transparent and bring this process out into the open," she said.

MISO says it will begin publishing new regional planning maps that show possible economic, reliability and generator interconnection needs on the same chart.

"We wanted a more holistic map of issues," expansion planning engineer David Ticknor explained to stakeholders. "This will hopefully allow us to coordinate and collaborate on holistic solutions … in planning cycles going forward."

Ticknor said the new maps will be updated periodically and contain indicators for generator interconnection thermal constraints, MTEP reliability constraints and congested flowgates that are possibly ripe for an MTEP economic project.

Ticknor said, for now, the maps will be educational and not used to propose transmission solutions.

"How are we going to move past the educational piece to use these maps for consolidated projects?" McIntire asked.

Ticknor said MISO will also begin internal and stakeholder discussions on project overlaps its planners have observed. "We figured starting off with a map was the easiest way to start a conversation about how things can work moving forward," he said.

Sustainable FERC Project's Lauren Azar asked if MISO is actively monitoring transmission assets that might be ripe for age and condition-related upgrades so it might find opportunities to consolidate project types even further.

Ticknor said MISO doesn't currently ask TOs for a list of impending upgrades to aging equipment but that it could look into maintaining such a list. ■

NYISO News

NY Regulators Approve 340-MW Alle-Catt Wind Farm

By Michael Kuser

The New York State Board on Electric Generation Siting and the Environment on Wednesday overrode local opposition to approve the 340-MW Alle-Catt Wind Farm south of Buffalo, the largest wind farm to pass *Article 10* siting review in the state (*17-F-0282*).

The *order* authorized the developer, Invenergy subsidiary Alle-Catt Wind Energy, to build and operate up to 116 wind turbines with associated infrastructure on approximately 30,000 acres spread across Allegany, Cattaraugus and Wyoming counties. The project had been under review since December 2017.

"In keeping with Gov. Andrew M. Cuomo's ambitious goals for carbon reduction and for a clean-energy economy, we must develop the clean energy resources in New York state needed to help all New Yorkers," said Siting Board Chair John B. Rhodes, who also serves as chair of the state's Public Service Commission.

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

Amish Outreach

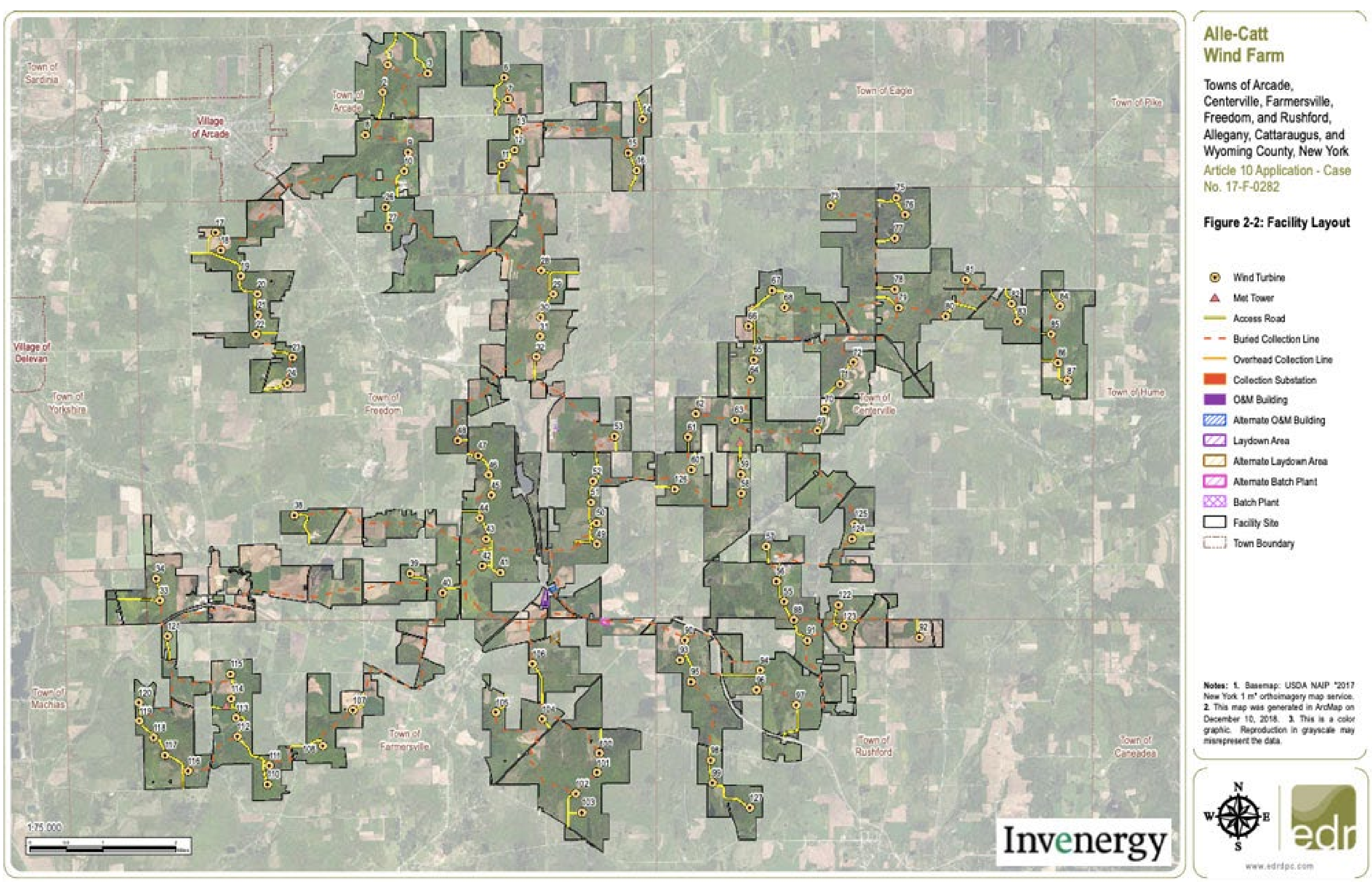
Former PSC Commissioner Gregg Sayre, now serving as administrative law judge for the Department of Public Service, presented to the Siting Board "three hotly contested issues in this case: the outreach to the Amish community, whether the project is a beneficial addition to the state's generation capacity and compliance with local laws."

The towns of Freedom and Farmersville took the position that the project should be rejected because there was ineffective outreach to the Amish community in Farmersville.

"There is a separate Amish community in another town, some members of which signed participating leases, but no one in the Farmersville community signed," Sayre said. "The draft order before you notes that in addition to the usual meetings, mailings and newspaper notices, Alle-Catt met face-to-face with members of the Farmersville community at one of their residences and discussed the project and took concerns raised by the Amish representatives."

Another argument was that every Amish household is effectively a church, as they regularly host worship services, but DPS examiners rejected that as unpersuasive, because a home would only host such a service, on average, once in 10 months, Sayre said.

The Concerned Citizens Coalition (CCC) *argued* that the project will not be a beneficial addition to the state's energy profile because



| *Invenergy*

NYISO News

transmission bottlenecks between upstate and downstate will, if not resolved in the future, constrain its capacity and cause its output to merely displace the output of other upstate wind projects.

The Siting Board rejected that position.

The order "acknowledges there are transmission constraints that will need to be addressed in the future but determines that the need to add transmission in the future is not a reason to reject new renewable energy projects now," Sayre said. "Requiring transmission to be built before a generation project is approved would be putting the cart before the horse."

Those constraints are being addressed in compliance with the recently enacted Accelerated Renewable Energy Growth and Community Protection Act, which provides for expedited transmission upgrades, Sayre said. (See *NY Renewable Supporters Push for New Siting Agency*.)

State Power and Symbols

"One of the most hotly contested issues in this proceeding is the application of the local laws ... because it's very complicated," Sayre said.

"Under the statute, the Siting Board applies substantive local laws to projects but may decline to apply any local law provisions that it finds to be unreasonably burdensome, with the applicant bearing the burden of proof," Sayre said. "In this case, the local laws in the towns of Freedom and Farmersville have changed a number of times, complicating the situation."

The Siting Board in effect sided with the developer, which *responded* to CCC's opposition to exceptions by arguing that the towns in question had misinterpreted the statute as "an open-ended authority in municipal legislative bodies to adopt laws that become applicable to projects when and as adopted."

DPS Chief Administrative Law Judge Dakin Lecakes presented the environmental review, which detailed the impacts of the project on various wildlife over its 30-year lifespan, as well as impacts on people using the state forest lands abutting the project.

For example, a setback of 1.1 times tip height will result in compliance with the 45-decibel sound limit for public lands; General Electric's 3.6-137 turbine has a tip height of 585 feet, which makes for a setback of 643.5 feet.

Following definitions set by the U.S. Fish and Wildlife Service and the state Department of Environmental Conservation, the order approved various curtailment strategies and mitigation plans for endangered species such as the bald eagle and the northern long-eared bat. ■

NYISO News

FERC OKs Negotiated Rates for Champlain Hudson Project

By Michael Kuser

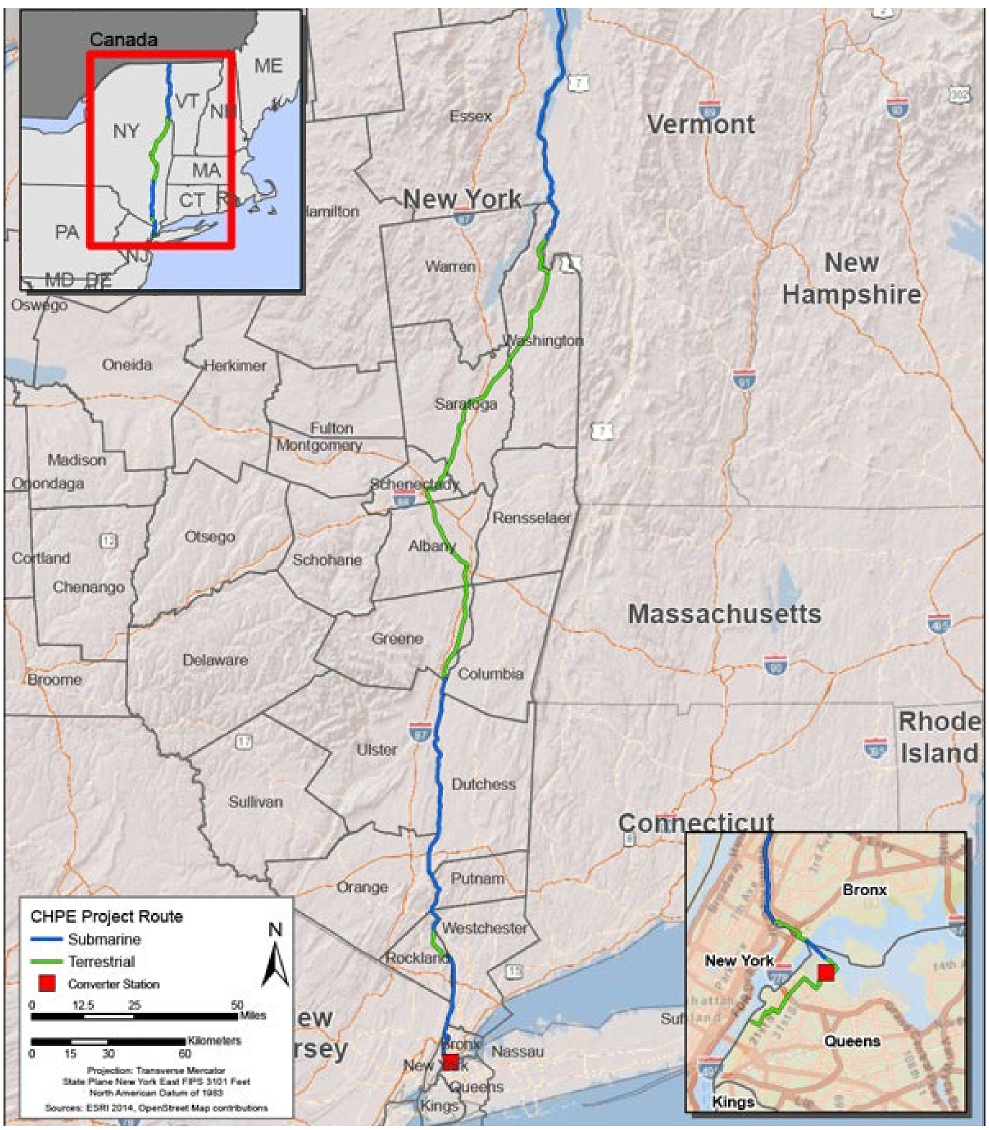
FERC has authorized the owners of the 1,000-MW Champlain Hudson Power Express (CHPE) project to charge negotiated transmission rates to carry Canadian hydropower to New York City.

The commission's May 29 order also granted the project developer's request for waiver of certain reporting requirements (*ER20-1214*).

The $3 billion HVDC merchant transmission proposal has succeeded in allying two Democrats who have not always got along well — New York City Mayor Bill de Blasio and Gov. Andrew Cuomo, though each in his own way has championed clean energy. (See *Cuomo Sets New York's Green Goals for 2020*.)

CHPE is owned by TDI-USA Holdings, which is in turn majority-owned by the investment firm Blackstone Group. Despite controlling $571 billion in assets, Blackstone does not own or control any existing electric transmission or distribution facilities in the markets operated by NYISO or Hydro-Québec.

Under commission precedent, merchant transmission projects differ from those of traditional public utilities in that the developers assume the full market risk of a project and have no captive customers from which to recover costs. Thus, the commission has allowed some such projects to be priced based on negotiated rates and has granted waivers of certain requirements.



Champlain Hudson Power Express project map | *Champlain Hudson Power Express*

FERC acknowledged CHPE's commitment to turn over operational control of the project to NYISO, comply with all applicable reliability requirements and provide the ISO with all required information necessary for its regional transmission planning process pursuant to Order 1000. The commission also noted that CHPE will retain "an experienced third-party independent expert" to advise the company on its open solicitation and capacity allocation process in order to ensure that its solicitation process is not "unduly discriminatory and preferential."

"We will, however, reserve judgment on whether the open solicitation and capacity allocation process once implemented are not unduly discriminatory, pending CHPE making a compliance filing within 30 days of the close of its open solicitation process," the commission said.

The commission granted CHPE's request for waiver of Part 141 of the commission's regulations, including the Form No. 1 annual reporting requirement for electric utilities, noting it has previously granted such waivers for other merchant transmission owners.

It also granted CHPE waiver of the full reporting requirements of Subparts B and C of Part 35 of FERC regulations, with the exception of sections 35.12(a), 35.13(b), 35.15 and 35.16.

Cuomo has recently spoken in favor of the CHPE project, prompting a swift protest from the Independent Power Producers of New York (IPPNY).

"This line is both unnecessary, given in-state developer demand, and provides no environmental benefit," said IPPNY President and CEO Gavin J. Donohue in a *statement*.

IPPNY in January released a *study* it commissioned from Energyzt showing that "the purchase of hydropower over CHPE will not result in reduced global emissions of carbon dioxide — and may even increase overall carbon emissions."

"Spending more than $3 billion to support the profiteering of a Canadian company on a project that will not revitalize the state's economy and will not actually provide an environmental benefit is a mistake," Donohue said. "Expanding New York's own renewable energy industry will allow for guaranteed emissions reductions while creating in-state jobs." ■

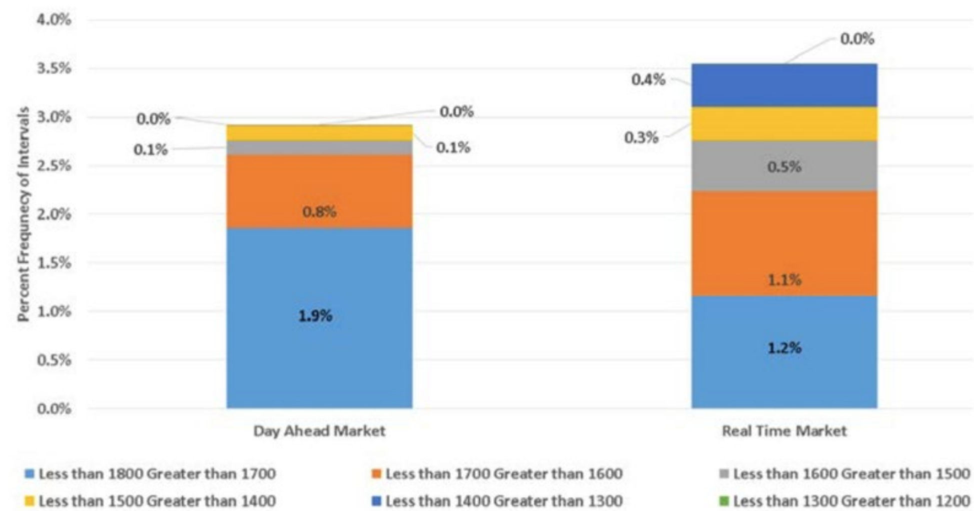
NYISO News

NYISO Gets Extra Time to Fix Market Software

FERC last week granted NYISO eight extra months — until year-end — to fix a "misalignment" between its market software and its Tariff rules (*ER20-1470*).

Section 4.4.1.2.1 of the ISO's Services Tariff allows generators that are committed day-ahead only for nonsynchronous operating reserves to modify their minimum generation bids in real time, but the ISO recently discovered that its software does not provide the flexibility intended by that provision.

NYISO explained that its software currently is preventing all generators, even those that only receive a day-ahead schedule for nonsynchronous operating reserves, from modifying their minimum generation bids in real time. The ISO said it expects to deploy the necessary software improvements coincident with its broader software revisions to implement fast-start pricing reforms that the commission already accepted in a February order (*ER20-659*).



NYISO reports 96.5% of RTD intervals had 1,800 MW or more of SENY 30-minute reserve procured. | *NYISO*

Granting the waiver "will allow NYISO to develop and implement software consistent with its business practices without the need to rush a software patch," the commission said.

However, the waiver will be in effect for only the period necessary for NYISO to code software modifications, perform the necessary quality assurance testing and deploy the software consistent with its standard software development practices, the commission said.

NYISO also asked the commission to "excuse any instances of past noncompliance with the provision at issue," adding that any such instances "cannot be corrected or reversed."

"Upon consideration, we will exercise our discretion in addressing such matters and, given the facts and the record before us in this matter, we take no action with respect to the instances of NYISO's past noncompliance," the commission said. ■

— Michael Kuser

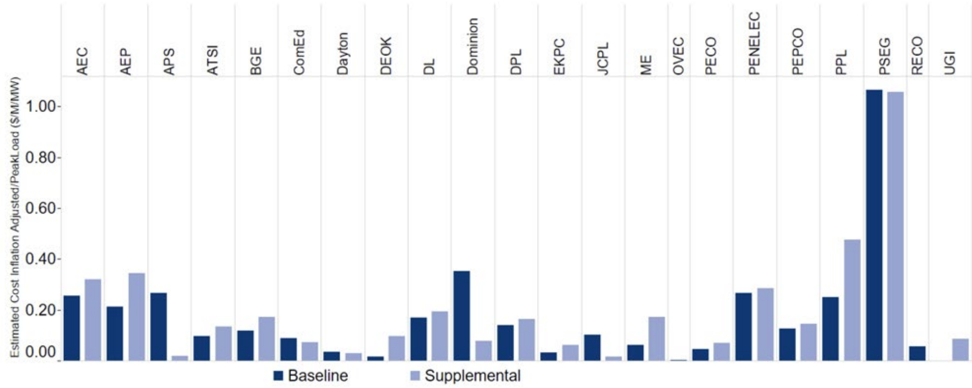
PJM News

PJM TOs Outline End-of-life Tariff Amendments

Traders' Votes Key to Narrow MRC Win

By Michael Yoder and Rich Heidorn Jr.

Stakeholders challenged a proposal by transmission owners to amend the PJM Tariff regarding end-of-life (EOL) projects, accusing them of attempting to take power away from the RTO in the Regional Transmission Expansion Plan (RTEP) process.



Baseline and supplemental projects since 2005 (adjusted by peak load) | *PJM*

The two-hour debate at the Transmission Owners Agreement-Administrative Committee (TOA-AC) on June 1 came on the heels of a contentious vote at the Markets and Reliability Committee meeting May 28 in which a "joint stakeholders" *proposal* from American Municipal Power (AMP), Old Dominion Electric Cooperative (ODEC) and others was narrowly defeated. (See *PJM End-of-life Proposals Fail at MRC*.)

Financial Traders Joined TOs in Opposition

The joint stakeholders proposal won 64% support in a sector-weighted vote in the MRC, just short of the two-thirds threshold required to send it to a final vote of the Members Committee.

A review of voting records indicates the TOs were aided in their opposition by financial traders within the Other Supplier (OS) sector. The OS voted 22-15 against the stakeholders' proposal at the MRC, with eight members abstaining.

When supporters of the proposal sought to suspend PJM rules to bring the issue to a vote of the MC despite falling short in the MRC, the OS voted 21-14 against the move, with three abstentions.

The MC reported that 13 of the 15 financial traders in the sector opposed suspending the rules, with one abstaining. Ten of the companies that voted against the suspension are represented by attorney Ruta Skucas of Pierce Atwood. Had the joint stakeholders been able to flip four OS votes at the MRC, the measure would have passed.

Ruta Skucas, Pierce Atwood | *Pierce Atwood*

In an interview, Skucas acknowledged casting the votes on her clients' behalf but declined to say why the traders opposed the proposal or how the EOL issue affects them.

"Part of this is being a member of a stakeholder body and working in coalitions and working in groups regardless of whether you're directly affected," she said.

Asked whether the traders had formed an alliance with the TOs, Skucas said, "I don't want to go into specifics," adding, "There are a number of TOs who engage in [financial transmission rights] trading."

The traders could be calling in their chits soon, as PJM is planning to hire a consultant to recommend whether the RTO's FTR and auction revenue rights (ARRs) markets should be changed to ensure more of the benefits go to load-serving entities rather than financial traders.

PJM's draft of the proposed scope of work poses nine issues for the consultant to address, one-third of which question the current market's balance between LSEs and other market players. Among the questions is whether "aspects of the current mechanism … result in profits to non-load-serving participants without commensurate or associated benefit to load." (See *PJM ARR/FTR Review Could Pit LSEs vs. Financial Traders*.) The *ARR/FTR Market Task Force* is scheduled to meet June 17 to discuss the work scope.

M-3 Presentation

During the TOA-AC webinar June 1, Chad Heitmeyer, director of RTO policy for American Electric Power, gave a *presentation* on the TOs' *proposal* to amend Attachment M-3 of the Tariff. Comments on the TOs' proposal were due Monday, with the TOA-AC set to vote on it at its *meeting* June 10.

Heitmeyer's presentation was similar to one he gave at a special meeting of the MRC on May 15. (See *TOs Back PJM End-of-life Proposal*.) He said PJM's grid faces degraded performance and a heightened risk of failure as it nears obsolescence. The RTO has *said* two-thirds of all system assets are more than 40 years old, and more than one-third are more than 50 years old.

"It's clear the system vital to our daily lives is aging," Heitmeyer said.

The current M-3 process provides significant transparency, requiring stakeholder review of supplemental projects a minimum of three times prior to inclusion in the PJM plan, Heitmeyer said. He said the new language will increase transparency and improve planning coordination with PJM while honoring the TOs' rights and responsibilities over asset management.

On May 7, the TOs gave *notice* that they were supporting the principles of a PJM EOL *package* and considering a Federal Power Act Section 205 filing to revise the Tariff to implement it. PJM's proposal would require TOs to have a formal program for EOL determinations and to identify potential EOL projects five years in advance. Projects that "overlap" with RTEP violations would be included in a competitive window seeking regional solutions. The RTO's proposal also failed to win consensus, with a sector-weighted vote of 1.77 (36%) at the May 28 MRC meeting.

PJM News

Heitmeyer's presentation included the red line changes proposed by the TOs in the Tariff, which include new sections on procedures for identifying and planning EOL needs and the coordination of EOL planning with PJM.

Process Challenged

Before Heitmeyer started his presentation, Ed Tatum of AMP questioned the process by which the TOs decided to announce the potential Section 205 filing, saying he didn't recall a vote at the TOA-AC. Tatum is a member of the TOA-AC through AMP Transmission.

Takis Laios of AEP, the outgoing chair of the TOA-AC, said a "supermajority" of the TOs had approached him and said they had the votes necessary for a Section 205 filing they wanted to take before stakeholders.

"It's not the proper manner of acting for a select number of TOs to make unilateral decisions and couch it on behalf of the TOA-AC," Tatum said.

Sharon Segner, vice president of LS Power, said the TOs' proposed Tariff amendments could lead to "fairly significant" changes in the RTEP process and were "significantly more expansive" than the language in PJM's proposal. She asked the TOs for a page-turn review of the proposed amendments.

FirstEnergy's Jeff Stuchell, the incoming chair of the TOA-AC, said a page-turn of the amendments had not been planned because of the scheduled length of the meeting and the time involved in a full review.

Segner asked to review the first page of proposed definitions as an "interesting place to start," pointing to the definition of an "Asset Management Project," which is "any modification or replacement of a transmission owner's transmission facilities that results in no more than an incidental increase in transmission capacity undertaken to perform maintenance, repair and replacement work, to address an EOL need, or to effect infrastructure security, system reliability and automation projects the transmission owner undertakes to maintain its existing electric transmission system and meet regulatory compliance requirements."

Segner said the definition seemed similar to language contained in two CAISO orders FERC issued in September 2018 (*EL17-45* and *ER18-370*), which she said did not define "asset management" or "incidental increase."

The TOs would define "incidental increase" as "an increase in transmission capacity achieved by advancements in technology and/or replacements … which is not reasonably severable from an asset management project."

Attorney Don Kaplan, representing the TOs, said the definitions were included in the proposed amendments because of stakeholder input and that the crafted language "broadly" defines asset management and incidental increase to comply with the California orders.

Kaplan said amending Attachment M-3 is permitted for the TOs if approved by FERC and that definitions can be codified given that they are consistent with applicable law.

"This is an expansion of stakeholder consultation and opportunity for input, which is not required by Order 890, and is beneficial to the planning process," Kaplan said.

Segner asked Kaplan why the EOL projects wouldn't be handled in the RTEP process versus Attachment M-3.

Kaplan said projects would be handled in the RTEP if they were expansions or enhancements and they were needed to address PJM planning criteria. He said the TOs' focus was projects that are not needed to address PJM planning criteria.

Segner cited language giving the TOs responsibility for planning and constructing "any other transmission expansion or enhancement of transmission facilities that is not planned by PJM to address … planning criteria," including NERC reliability standards, individual TO planning criteria, criteria to address economic constraints, "state agreement" projects or RTEP projects.

Segner said the proposed language seemed to reduce the types of projects that are regionally planned. "It looks like a [power] grab to me," she said.

Kaplan said the first four categories are the only planning responsibilities that have already been transferred from the TOs to PJM. Kaplan said the last clause expands the coverage of Attachment M-3 to projects not delegated to PJM. ■

Do you support the motion to suspend the rules to allow for failed MRC package to be voted at MC?

Vote	Company Name
Abstain	Jersey Green Energy, LLC
No	Appian Way Energy Partners MidAtlantic, LLC
No	Strom Power, LLC
No	Prime Trading, LLC
No	Ames Energy, LLC*
No	Big Bend Trading, LLC *
No	BJ Energy, LLC*
No	Dufossat Capital I, LLC*
No	Greene Energy NE LLC*
No	Hexis Energy Trading, LLC*
No	Precept Power LLC*
No	Pure Energy, Inc.*
No	Red Wolf PT, LLC*
No	Taller Cube, LLC*
Yes	Gerdau Ameristeel Energy, Inc.

* Company represented by attorney Ruta Skucas

Thirteen of 15 financial traders voted against considering the joint stakeholders' end-of-life proposal at the Members Committee meeting May 28. Ten of those that voted "no" are represented by attorney Ruta Skucas. | *PJM*

PJM News

FERC OKs Tougher PJM Credit Rules

Glick, Danly Call for More Action

By Rich Heidorn Jr.

Companies seeking to participate in PJM's markets must provide the RTO with more financial records, corporate information and details of prior defaults under rules effective June 1.

FERC approved the tougher rules May 27, turning aside a protest from Dominion Energy, which said the RTO's proposal was ambiguous (*ER20-1451*).

The new requirements for managing market participants' credit risks arose from the 2018 GreenHat Energy default in the financial transmission rights market.

PJM will determine whether a company presents an "unreasonable credit risk" based on factors including a history of market manipulation, financial defaults or bankruptcies within the past five years. It also will consider market and financial risk factors such as low capitalization, future material financial liabilities and low credit scores.

To allow PJM to conduct ongoing risk evaluation, companies also must make annual officer certifications and notify the RTO of any "material adverse change in the financial condition of the participant or its guarantor."

The proposals won a 90% sector-weighted vote at the Members Committee in March and generally supportive comments from intervenors. (See *PJM Members OK Tighter Credit Rules*.)

Dominion, the only intervenor to protest in the FERC docket, complained that PJM's process for choosing when it uses external credit ratings and when it uses internal credit scores was vague and required clarification. It balked at giving PJM discretion to use its internal credit score even when external credit ratings are available, saying it will make it difficult for an applicant to determine how much credit the RTO will extend it. It said PJM should only be permitted to use its internal credit score when an external credit rating is unavailable. Dominion also said PJM failed to clearly define the term "unreasonable credit risk."

FERC approved PJM's filing without revisions, saying, "It is impractical to enumerate all of the examples that constitute an unreasonable credit risk, as doing so may unnecessarily limit when an RTO can act to protect its wholesale markets and market participants to only those specified instances enumerated in the Tariff."

The commission said the new rules are consistent with Order 741, which allows RTOs discretion in requiring additional collateral in response to changed circumstances.

"It is common for financial institutions and large business organizations to utilize multi-dimensional credit scores and internal ratings of quantitative and qualitative factors as a way to standardize the evaluation of an entity's credit risk. We also note that, previously, PJM was only able to rely on external credit ratings, which … do not reflect market or liquidity risk and can go stale quickly.

"With the ability to consider both external credit ratings and its internal credit score, PJM will have more insight and visibility into the credit risk posed by a particular applicant or market participant and can react quickly to minimize financial exposure," the commission said.

FERC denied Dominion's contention that PJM's proposal is unreasonably vague, saying the RTO's promise to provide entities with their internal credit score provides transparency while also reducing the opportunity for a market participant to deliberately influence its internal credit score.

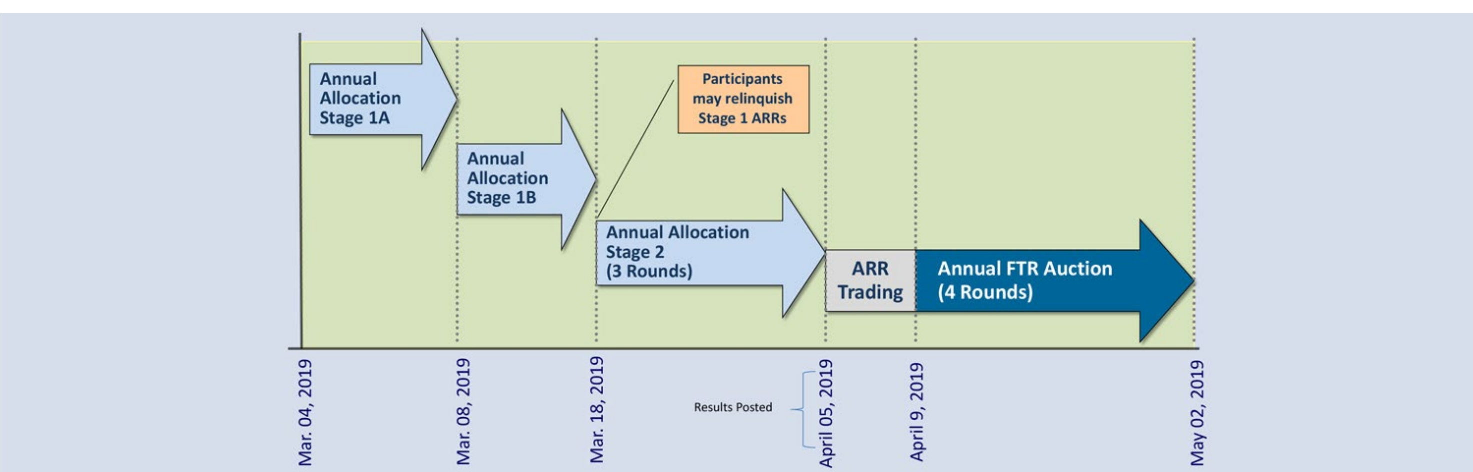
Concurrence

Commissioners Richard Glick and James Danly concurred on the proposed changes, which they said were "at least as exacting" as rules the commission has approved for MISO and NYISO.

But in a joint statement, they said they were "somewhat uneasy" with the discretion given PJM in making creditworthiness decisions.

"These revisions represent an important first step in enhancing PJM's credit risk evaluation process, but they are just that: a first step. Further changes should be considered, not only in PJM, but in all the organized markets," they continued, referencing the Energy Trading Institute's December petition seeking a technical conference on credit and risk management (*AD20-6*). (See *RTO Council Balks at Credit Rulemaking*.)

They urged their colleagues to join them in supporting the conference, saying it would be a "timely vehicle for the commission to engage in a much-needed discussion on these important issues." ■



Annual ARR/FTR market timeline | *PJM*

PJM PC/TEAC Briefs

Planning Committee

Reserve Requirement Study Assumptions

The PJM Planning Committee on June 2 unanimously endorsed the 2020 Reserve Requirement Study assumptions, which reset the installed reserve margin and forecast pool requirement (FPR) for 2021/22 through 2023/24 and establish the initial levels for 2024/25.

Jason Quevada of PJM presented the assumptions, which were developed in the Resource Adequacy Analysis Subcommittee (RAAS). The 2020 assumptions are similar to those in 2019 except for the modeling of wind and solar, Quevada said during the PC's meeting.

Previously, capacity values for wind and solar generators with three or more years of operating data were set based on their actual performance, with values for newer wind units set based on a combination of actual performance and class average capacity factors. The new Capacity Capability Senior Task Force will be meeting this year to develop a method for calculating wind and solar capacity values using effective load-carrying capability (ELCC), a measure of the additional load that a group of generators can supply without a reduction in reliability. (See AWEA Balks at PJM Plan on Wind, Solar Capacity.)

The ELCC approach, which is intended to address the underestimation of wind and solar output variability, is expected to have a minimal impact on the FPR.

The reserve requirement values will be based on a capacity benefit margin — the amount of transmission import capability reserved for emergency import sales — of 3,500 MW, the same as 2019. PJM will also continue using a load forecast error factor of 1%.

Staff will use the PRISM model to develop a cumulative capacity outage probability table for each week of the year except the winter peak. For the winter peak week, staff will create a table based on RTO-aggregate outage data collected between 2007/08 and 2019/20 to account for the risk caused by the large volume of concurrent outages observed during that time frame.

The final report is planned to be presented to the RAAS and the PC in September, with final approval in October.

Load Impact and Forecast Update

Andrew Gledhill of PJM's resource adequacy planning unit presented the estimated COVID-19 impacts on load. Gledhill said that since March 24, weekday peaks have averaged 10.4% less (9,300 MW) than projected before the coronavirus pandemic. The weekday peak impacts have ranged from 0.6 to 15%, and the biggest impact to load forecasting came in the first week of May.

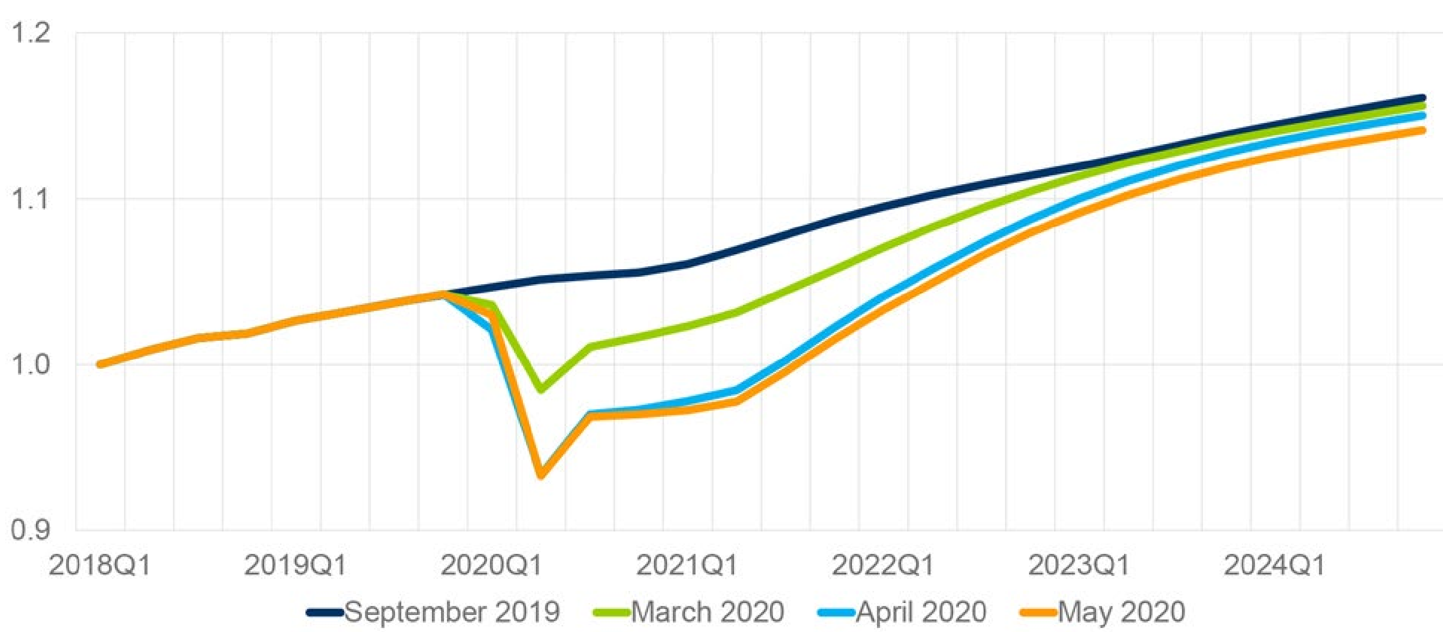
While impacts in May were generally larger than April, Gledhill said PJM believes some of the impact is because of increased "weather sensitivity" — increased cooling loads with summer's arrival.

On May 26, for example, when the RTO's weighted average daily temperature was above 70 degrees Fahrenheit, peak load was only 0.6% below expected.

Overall energy consumption has been less affected by the pandemic, Gledhill said, with the average reduction since March 24 being 8%. Recent data suggest the reduced trend could be starting to change, he said, as a result of weather sensitivity and the lifting of stay-at-home orders across the country.

PJM last month asked FERC to approve a waiver allowing the RTO to post a revised peak load forecast for the second Incremental Auction for delivery year 2021/22.

The RTO posted its initial forecast for the auction before Feb. 1. The revised forecast reduces peak loads by 1.7% for 2020 and 1.6% for 2021, based on Moody's Analytics' April 2020 Economic Forecast, which predicts that third-quarter 2021 real GDP will be 7.1% low-



Moody's Analytics' forecast of U.S. real GDP | *PJM* er than assumed in PJM's posted load forecast.

PJM asked FERC to respond no later than June 15, three weeks before the start of the IA on July 6. PJM is publishing two sets of planning parameters for the auction, Gledhill said, with the first set based off the 2020 forecast and the second set based off the updated April forecast. If FERC approves the waiver, PJM will use the second set.

Competitive Planner Update

Ilyana Dropkin of PJM presented an *update* on the Competitive Planner, a web-based application for transmission owners and developers to participate in the RTO's competitive planning process under Order 1000.

The current PJM process for proposal submission relies on an Excel template. Dropkin said that having a web-based application increases the speed and accuracy of the process and provides near-real-time tracking of submissions.

Beta testing was implemented May 6-20, Dropkin said, and volunteers suggested improvements and provided feedback about how the application compares to previous methods for submitting proposals.

Dropkin said registration for the new application is scheduled to begin June 22, and it will be opened for use about July 1.

Those looking to participate in the competitive planning process can get access to Competitive Planner by *prequalifying* through the critical energy/electric infrastructure information (CEII) process, Dropkin said.

Transmission Expansion Advisory Committee

Generation Deactivation Notification

Phil Yum of PJM provided the Transmission Expansion Advisory Committee an *update* on recent generation deactivation notifications, including a request received in May for Dickerson Units 1, 2 and 3. The coal-fired plant in Dickerson, Md., totals 545 MW.

According to a press release from plant owner GenOn Holdings, Units 1, 2 and 3 came online in 1959, 1960 and 1962, respectively. GenOn said the decision to deactivate the coal units was "driven by unfavorable economic conditions and increased costs associated with environmental compliance."

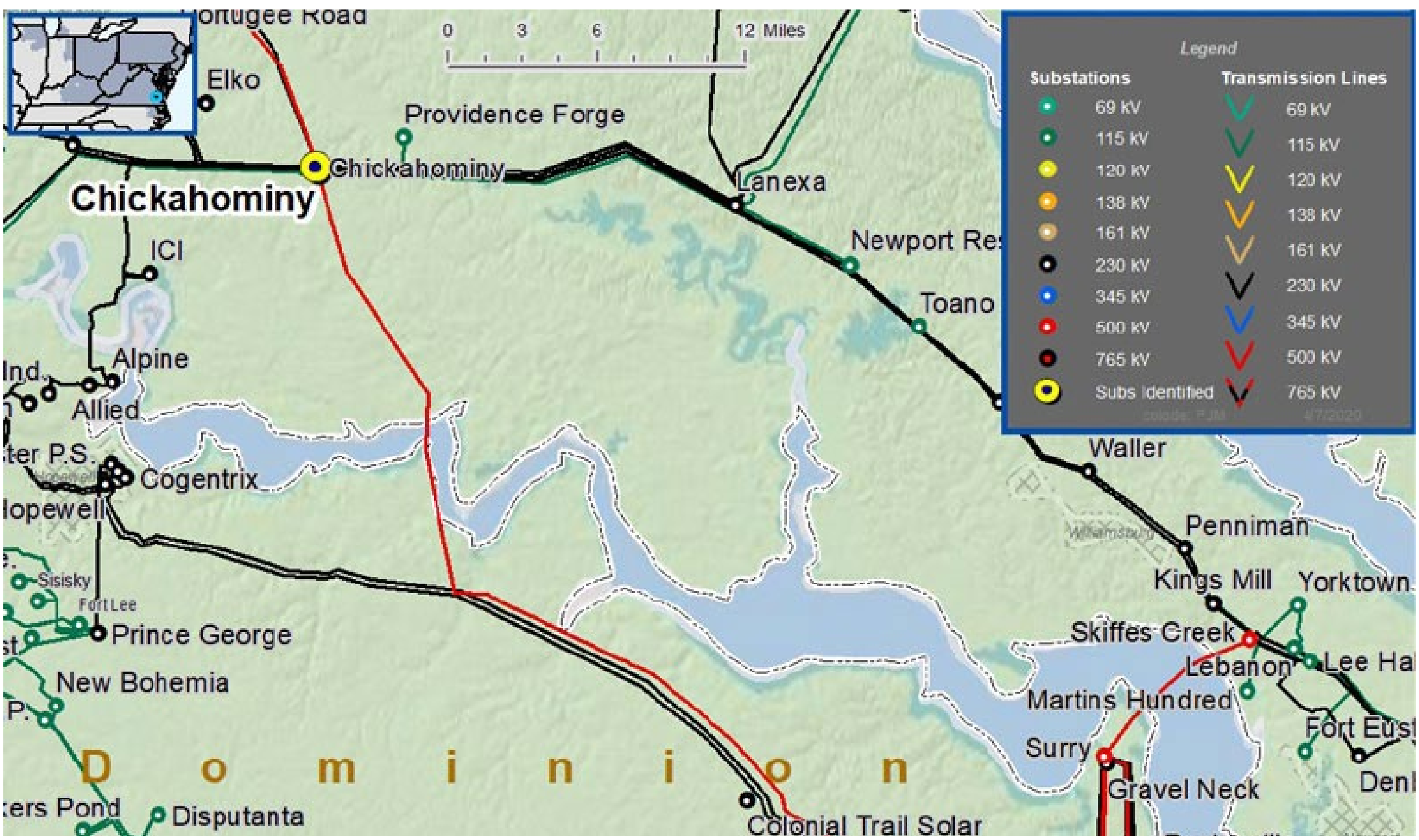
GenOn requested a deactivation date of Aug. 13. The company will continue operating approximately 312 MW of natural gas- and oil-fired generating capacity at the site. Yum said a full result of the reliability analysis of the deactivation will be presented at the July TEAC meeting.

Yum also presented a second read of the deactivation of Chesterfield Units 5 and 6 (1,015 MW) in the Dominion zone, which are scheduled to retire on May 31, 2023. Yum said a generation deliverability problem was discovered at the Chickahominy 500/230-kV transformer, which would be overloaded with the loss of the Chickahominy-Surry 500-kV line.

PJM is recommending installing a second Chickahominy 500/230-kV transformer at an estimated cost of $22 million.

A second read was also presented on several transmission upgrade projects related to the reinstatement of the Shippingport, Pa.-based Beaver Valley nuclear plant in March. (See *Beaver Valley Nuclear Plant to Stay Open*.) ■

— Michael Yoder



Dominion transmission zone | *PJM*

PMU Vote Delayed by PJM

By Michael Yoder

Voltage Threshold	New dynamic reactive device	New Line	Line rebuild / reconductor	Line rebuild / reconductor (partial)	New Transformer	New Substation	Substation Rebuild	Total
115	17	161	272	81	137	106	115	889
138	16	135	225	59	103	84	82	704
161	8	51	78	19	41	29	30	256
230	8	50	77	19	41	29	30	254
345	2	14	20	7	18	4	9	74
500	2	4	11	3	4	1	4	29
765	1	0	0	1	1	0	1	4

Types of projects under the PMU Placement Strategy | *PJM*

PJM's Planning Committee postponed a vote by one month on "quick-fix" manual revisions to implement the RTO's plans to expand the use of synchrophasors and make them a requirement for certain projects under the Regional Transmission Expansion Plan.

Stakeholders were scheduled to vote on the *issue charge* and endorse the *proposed* manual language at the June 2 PC meeting to require synchrophasors — also known as phasor measurement units (PMUs) — in all new substations and major construction projects to monitor bus voltage and line flows.

Some members said they were concerned about using the quick-fix process to endorse the changes and questioned PJM staff about missing Tariff language in the proposal.

Dave Souder, PJM's senior director of system planning, said the PMU expansion will improve reliability and give operations staff the tools they need for the increasingly dynamic monitoring needs of the grid. Souder said he recognized some stakeholders may have issues with the quick-fix method, so he requested that members express their concerns about the proposed manual language in advance of the July PC meeting.

"I really don't want to force a quick-fix solution down the stakeholders' throats," Souder said.

Shaun Murphy of PJM reviewed the PMU problem statement, issue charge and proposed solution at the meeting. In his *presentation*, Murphy said language is being proposed for section 1.4.1.3 of *Manual 14B* to add a PMU Placement Strategy (PPS) to identify the synchrophasor device coverage needed to support the RTO's real-time synchrophasor applications. The PPS, which includes placement targets and required operational dates, would make mandatory a program that is currently voluntary.

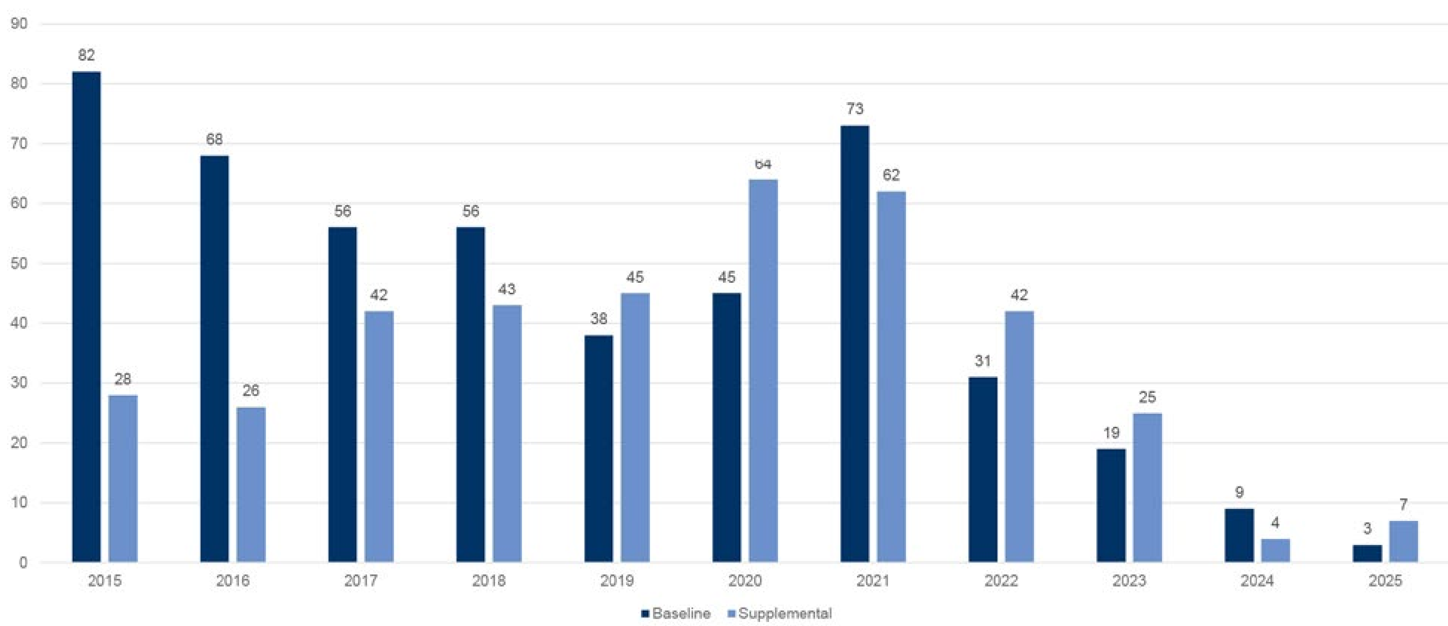
Murphy said instituting the PPS would close the gap between research and real-time control room use and improve data reliability and oscillation detection. (See *Oscillation Event Points to Need for Better Diagnostics*.)

Making each substation "PMU ready" costs as much as $120,000, he said, and each substation would have two or three PMUs that cost about $10,000 each. As many as 889 projects could be created over a 12-year span if a voltage threshold of 100 kV for each unit is accepted, according to PJM. The PMU requirement would be effective for projects presented to the Transmission Expansion Advisory Committee after June 1, 2021.

Murphy said about 80 PMUs will be added each year at a cost of about $8 million annually.

Tom Hyzinski of GT Power Group said the yearly price tag seemed reasonable compared to the value of the information that could identify costly problems on the system. Hyzinski asked if there was any discussion by PJM on ways the cost could be allocated across stakeholders so that no one would be greatly impacted by the expense.

Souder said PJM was open to discussing cost allocation among stakeholders, but he said the RTO felt PMUs have to be expanded across



PJM identified nearly 900 possible projects under its proposed PMU Placement Strategy. | *PJM*

PJM News

the system to be effective. Souder said the technology would be required for both baseline and supplemental projects to spread the technology.

Dave Mabry of the PJM Industrial Customer Coalition (ICC) said he was thankful for the educational session PJM held on May 26 on PMUs and their benefits to the system. He asked if there were any Tariff changes considered in the PJM proposal, noting that the Tariff makes references to PMUs in generation interconnection.

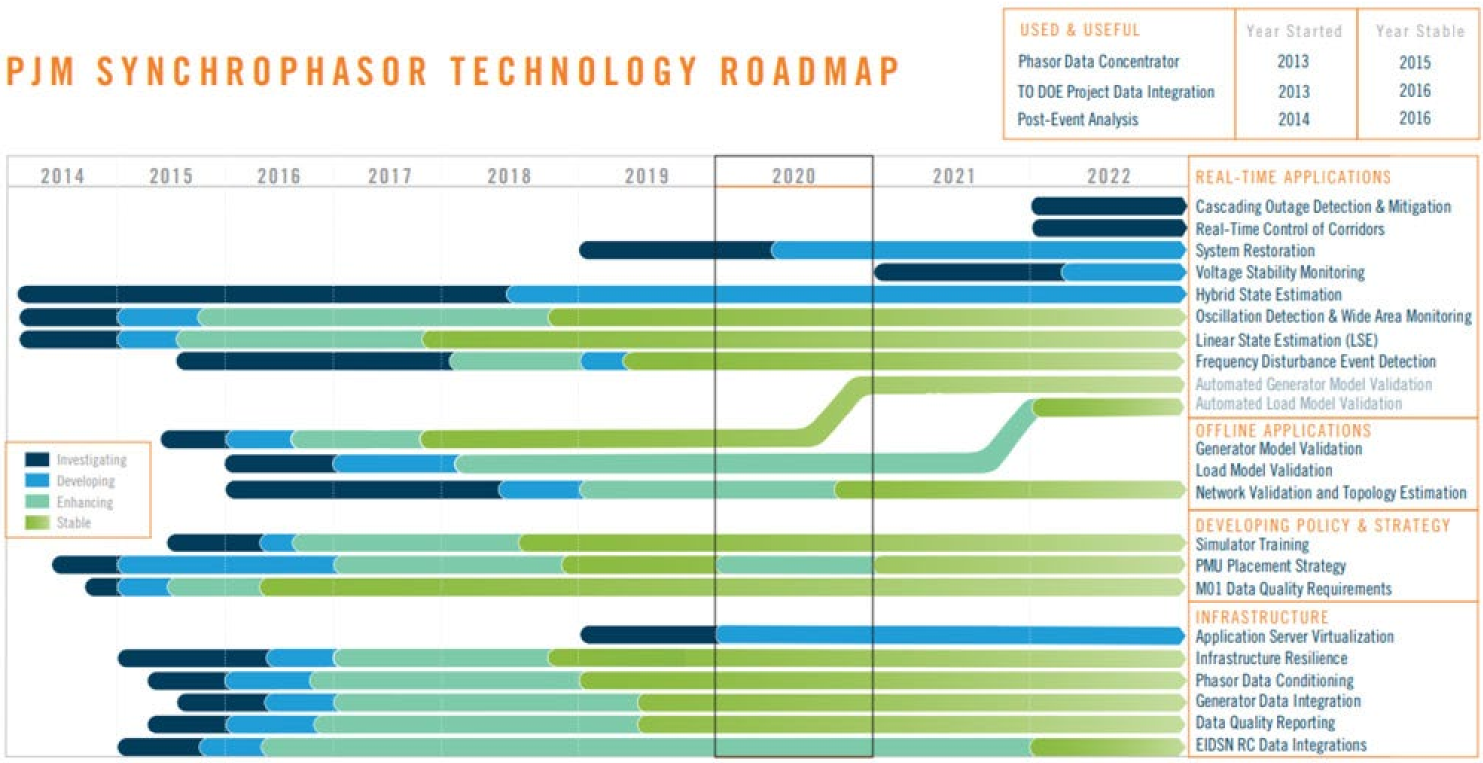
Souder said PJM's legal review concluded the manual language was sufficient.

Mabry said the ICC opposed using the quick-fix solution and thinks the issue would benefit from further consideration by stakeholders regarding the implementation strategy and cost allocation. He said the education session convinced the ICC to support the problem statement but that the group still has reservations about the PJM proposed solution and is concerned that it will increase the justification of supplemental projects, which are reserved for incumbent transmission owners and not subject to competitive bidding.

"We don't want to implicitly approve supplemental projects we have questions about," he said. "Our concern is whether PMUs are going to become a nexus for trying to justify supplemental projects."

Souder said he understood that stakeholders have concerns about supplemental projects but said if PJM only requires PMUs in baseline projects, it will limit the ability to propagate the technology across the system.

"It truly is a catch-22," Souder said. "We need the data across the systems so we can fully utilize the tools." ■



| PJM

PJM Operating Committee Briefs

Black Start Rules

PJM presented the Operating Committee with proposed *rule changes* concerning the testing, compensation, substitution and termination of black start resources Thursday.

Most of the changes involve additions to Schedule 6A of the Tariff and section 4.6 of Manual 12, said PJM's Becky Davis, who walked stakeholders through a matrix of revisions. She said redline versions of the Tariff and manual language will be available for review by the OC's July 9 meeting.

The committee approved an issue charge for the initiative at its May meeting. (See "Black Start Issue Charge Endorsed," *PJM Operating Committee Briefs: May 14, 2020*.)

The *problem statement* focuses on four areas:

- Making units that entered black start service through a transmission owner integration subject to the same testing requirements as those compensated under Schedule 6A: a successful test every 13 months.
- Clarifying rules for substituting one black start unit for another. Current rules allow a black start unit owner to substitute one unit for another if the substitute is on the same voltage level and has a valid annual test. PJM said it is responding to an increase in questions about adding, maintaining and managing black start substitutes. The proposed rules would require 40 days' notice for substitution requests.
- Adding language allowing PJM to replace black start units that fail or do not perform tests without lengthy delays.
- Allowing updates to the capital recovery factor table governing compensation for black start capital costs to remain consistent with current tax law and interest rates.

PJM attorney Steve Pincus said the RTO is not concerned over potential conflicts between its rules and black start units covered by "legacy" agreements with TOs.

Pincus said PJM would look at the agreements on a case-by-case basis to resolve any potential conflict, noting there are only a "handful" of agreements that fall into that category. He said the PJM testing rules are likely more stringent than those in the legacy agreements but that if an agreement with TOs was more demanding than PJM's, "I'm confident we would not have a Tariff [violation] issue."

If necessary, Pincus said PJM would seek a Tariff waiver from FERC to address any inconsistencies.

In addition to the four topics in the problem statement, the OC also will consider how to compensate black start owners for their fuel costs under the minimum tank suction level (MTSL) rules. The Markets and Reliability Committee approved the expansion of the initiative to cover MTSL on May 28. (See "Fuel Requirement Issue Charge," *PJM MRC Briefs: May 28, 2020*.)

Dispatch Interactive Map Application

Ed Kovler of PJM conducted a first read of a proposed *problem statement* and *issue charge* to consider giving TOs access to the Dispatch Interactive Map Application (DIMA), a geospatial situational awareness tool that the RTO's dispatchers have used since 2014.

PJM and several TOs brought forward *draft language* for the Operating Agreement to be endorsed through the "quick fix" process documented in Manual 34. The OC will vote on the issue charge at its July 9 meeting.

DIMA allows operators to see the location of problems on the grid in real time and respond quickly.

Kovler said DIMA has been a "paradigm shift" for PJM dispatchers, moving away from old tabular displays that most operation centers have to a geospatial display that helps them better understand the relationship of equipment.

TOs have requested read-only access to DIMA to improve their own operators' situational awareness, Kovler said.

PJM plans to present the DIMA issue charge at the July and August MRC meetings and the September Members Committee meeting. If endorsed, the OA changes will be sent to FERC in September for review.

Kovler said PJM expects FERC to act in about 60 days and that the RTO will begin implementing the increased access "almost immediately" afterward.

"There's a lot of IT work that needs to be done," Kovler said, estimating it could take more than five months to complete. A "phased rollout" could take several months more to complete, he said. ■

— Michael Yoder

DIMA geospatial overview | *PJM*

PJM MIC Briefs

Solar-Battery Hybrids

The PJM Market Implementation Committee on Wednesday endorsed an initiative to update the RTO's business rules to accommodate co-located generation and energy storage hybrid resources.

The *issue charge* passed unanimously by acclamation and is set to be overseen by the proposed Distributed Energy Resource and Inverter-based Resources Subcommittee (DIRS).

Scott Baker, PJM business solutions engineer, provided a first read of the *problem statement* and issue charge for the effort, which will define how current requirements for solar parks, solar resources, intermittent resources and energy storage resources do and do not apply to generation-battery hybrids.

The focus of discussions will initially be centered on solar-battery resources, which represent more than 95% of the more than 10,000 MW of hybrids in the PJM interconnection queue. But the issue charge allows for investigation of other hybrid resources like wind-battery, gas-battery or any other combination. Baker said that as a result of stakeholder feedback at the Markets and Reliability Committee, the issue charge calls for the subcommittee to begin work in July and report its findings and proposed solutions to the MIC by the end of 2020. (See "Action on Hybrid Resource Initiative Deferred on Venue Question," *PJM MRC Briefs: April 30, 2020*.)

Baker said the solar-battery hybrid issue assignment was intentionally left blank because the MIC is also discussing the consolidation and creation of the DIRS. He provided the first read of the *charter* for the new subcommittee and a *proposal* to sunset the Intermittent Resources Subcommittee (IRS). The IRS originated as the Intermittent Resources Working Group in 2008 to address *issues* regarding operations and reliability, energy markets, capacity markets and interconnections.

| © RTO Insider

Scott Baker, PJM | © RTO Insider

Baker said that although DIRS would operate under the MIC, stakeholders requested that the subcommittee also coordinate with the Planning and Operating committees. Baker said many of the issues discussed at DIRS could affect both markets and operations.

PJM will seek endorsement of the new subcommittee at the next MIC meeting on July 8.

PRD Credits Disposition

Sharon Midgley of Exelon provided a first read of the *problem statement* and *issue charge* addressing the price-responsive demand (PRD) credits disposition. The issue calls for the MIC to review the market design to determine if the current load-serving entity PRD credits are appropriate and to explore alternative allocations.

PRD providers represent retail customers that have the capability to reduce load in response to prices. Midgley said current PJM settlement rules do not address electric distribution companies (EDCs) or curtailment service providers (CSPs) that do not have direct responsibility for serving retail load but otherwise meet the eligibility requirements of a PRD provider.

All revenues associated with PRD are credited to the LSE for the area, Midgley said, meaning some market participants are paid for PRD service that an EDC or CSP is supplying while performance penalties stay with the PRD provider.

The committee will vote on the issue charge endorsement at its July meeting. The work effort is expected to take six to nine months, with changes implemented in advance of the 2021/22 delivery year.

Performance Assessment Interval Settlements

Danielle Croop of PJM conducted a first read of a *problem statement* and *issue charge* to increase transparency in settlement calculations for nonperformance charges, including ancillary service accounting and the determination of scheduled megawatts. It will also include provisions to make language for energy-only and demand response resources parallel with that of generation resources.

In March, PJM released a *report* on performance assessment interval (PAI) settlements as an addendum to its *review* of the Oct. 1-2, 2019, performance assessment event, when an abnormal heat wave led to emergency procedures and the first call on DR resources in more than five years. (See *PJM, Stakeholders Baffled by DR event*.)

The incident resulted in $8.2 million in nonperformance charges. Bonus payments averaged $32.89/MW-interval, with the average amount of megawatts eligible for bonuses during the event being 9,706.

In her *presentation*, Croop said PJM staff found the settlement calculations for the Oct. 1-2

PJM News

emergency event lacked transparency. A market notice was posted on PJM's capacity market *webpage* detailing how the RTO settled the charges and credits.

Croop said the RTO will seek stakeholder input on business rules not described in detail in the governing documents. The initiative will memorialize the business rules in the appropriate agreements and manuals without changing the substance of Capacity Performance rules.

Independent Market Monitor Joe Bowring said he disagreed with some of PJM's proposed language changes, calling it "subjective" and difficult to interpret. Bowring said some of the proposed rules may not be consistent with CP.

"We want to make sure the end result is that this process works properly," Bowring said.

The MIC will vote on the issue charge approval at its July meeting.

FERC Transmission Orders

PJM's Ray Fernandez provided *updates* at both the MIC and the June 2 Planning Committee meeting on the cost allocation impacts of two recent FERC orders requiring resettlement.

In the first order, FERC ruled that PJM must rebill parties to reverse incorrect cost assignments of Form 715 transmission projects. The costs, which had been allocated 100% to the zone of the host transmission owner, have been spread more widely, reflecting the projects' regional benefits. (See *FERC Stands Firm on Form 715 Assessments*.)

PJM found 44 projects impacted by the order, including 33 in the PSEG zone and 11 in the Dominion zone.

Dominion Energy will collect almost $28.5 million in refunds from two dozen other transmission zones, led by American Electric Power and Commonwealth Edison, which will be billed more than $4 million each, according to an estimate *posted* by PJM on May 27.

Public Service Electric and Gas is owed $53.2 million from five companies, led by Linden VFT ($19 million), Neptune ($15.2 million) and Consolidated Edison ($13.2 million). PJM cautioned that the revised cost assignments could change based on FERC rulings or additional review by the RTO.

In the second order, FERC ruled that two merchant transmission operators in New Jersey are still liable for some cost allocations under PJM's Regional Transmission Expansion Plan (RTEP) despite converting from firm to non-firm service after the cancellation of the Con Ed-PSEG "wheel" in 2017 (*ER18-680*). (See *FERC Rejects Cost Formula for NJ Merchant Tx*.)

Linden and Hudson Transmission Partners (HTP) own merchant transmission facilities that carried power into New York City as part of the wheel, in which 1,000 MW were exported from upstate New York to PJM through PSE&G facilities in northern New Jersey, and then exported to the city. Con Ed and PSE&G canceled the agreement in April 2017, prompting HTP and Linden to convert their firm transmission withdrawal rights (TWRs) to non-firm TWRs.

HTP would be billed $24.1 million and Linden $5.7 million under PJM's resettlement estimate. PSE&G is the biggest beneficiary, due $22.9 million.

Linden, Long Island Power Authority, Neptune and the New York Power Authority (NYPA) made requests for a rehearing to FERC, Fernandez said. Linden and NYPA also requested settlement relief if FERC does not grant a rehearing request by delaying billing until January 2021 and to allow for a 12-month settlement period in equal installments from Jan. 1, 2021, through Dec. 31, 2021 ■

— Michael Yoder

PJM News

PJM 5-Minute Dispatch Proposal Endorsed

By Michael Yoder

Stakeholders gave a nearly unanimous endorsement of PJM's short-term *proposal* to resolve issues in *five-minute dispatch and pricing* at Wednesday's Market Implementation Committee meeting but urged the RTO to continue seeking intermediate and long-term solutions.

PJM's proposal won 96% support, with 205 members voting in favor, nine against and 31 abstaining. In a nonbinding vote that asked whether members preferred the package over the status quo, the measure passed with 100% support: 218 "yes" votes and 18 abstentions. "I don't think I've seen this before," said Bhavana Keshavamurthy of PJM.

The RTO's proposal will have a first read at the June 18 Markets and Reliability Committee meeting and a July vote at the MRC and Members Committee meetings. Pending FERC approval, implementation is tentatively slated for October.

Tim Horger of PJM presented the *highlights* of the package, which calls for "work streams": short-term market changes to address pricing alignment; "enhancements and clarifications" to LMP verification; intermediate operational changes to implement more "regimented" real-time security-constrained economic dispatch (RT SCED) case approvals; and long-term operational changes to investigate changing SCED timing and consider previous dispatch instructions.

Horger said PJM decided to break the process up into short-term, intermediate and long-term efforts based on how quickly they could be implemented.

PJM's proposed short-term fixes would align the locational price calculator (LPC) to use the reference RT SCED case for the same target time. The LPC would calculate prices for the interval from 11:55 a.m. to 12 p.m. using the RT SCED solution for a 12 p.m. target time.

Paul Sotkiewicz, E-Cubed Policy Associates | © *RTO Insider*

Resource offers, parameters and ancillary service assignments would be inputs to the RT SCED cases. Offers for 11 a.m. to 12 p.m. would be effective through 12, with offers for 12 to 1 p.m. used for the dispatch target 12:05.

FERC ordered PJM last year to revise its Tariff to allow fast-start resources to set clearing prices. In January, the commission voted to hold the RTO's fast-start pricing compliance filing in abeyance until July 31, agreeing with the Independent Market Monitor and others who said resources' compensation don't correspond to their dispatch instructions because PJM uses different market intervals to calculate prices and dispatch. (See *FERC Stalls PJM Fast-start Compliance Filing*.)

After attempting to craft a joint proposal in response to FERC's January ruling, PJM and the Monitor told the MIC in April that they were unable to agree on implementation timing. (See *PJM, IMM at Odds on 5-Minute Dispatch, Pricing Rules*.)

In addition to making changes to settlements as in the PJM plan, the Monitor also *proposed* changes to dispatch and SCED calculations. "This is an important price formation issue in PJM," said the Monitor's Catherine Tyler.

The Monitor's proposal failed with only 32% support at Wednesday's MIC meeting.

Wednesday's vote on the PJM package was limited to the short-term changes, Horger said, and not whether they address the issues the Monitor raised in the fast-start pricing docket. Stakeholders can opine on whether the short-term fix satisfies FERC's concerns in comments on PJM's filing, Horger said.

Paul Sotkiewicz of E-Cubed Policy Associates said many stakeholders are still looking to PJM to move fast-start pricing along in the process and asked if short-term fixes could be a major component of the issue.

Horger said the short-term changes are beneficial regardless of what happens with fast-start pricing. He said PJM's legal view is that short-term changes will meet the fast-start directives from FERC.

PJM is also committed to the intermediate changes, Horger said, but it doesn't think they are necessary for fast-start pricing.

"We have not heard a firm commitment [from PJM] on even the intermediate" solution, countered Monitor Joe Bowring.

Tim Horger, PJM | © *RTO Insider*

Becky Carroll of PJM gave an operational update on the intermediate changes the RTO is pursuing. Carroll said a 48-hour test of the five-minute auto case execution was successfully completed before Memorial Day.

Carroll said no concerns were found during the test. The next test of the system is planned for June 22, she said, and if it is successful, PJM will use the procedure permanently and draft manual changes documenting it.

Adrien Ford of Old Dominion Electric Cooperative said her company supports PJM's short-term changes but would also like to see the intermediate and long-term changes fully pursued. She said she struggles when she hears PJM officials use the phrase "committed" to intermediate changes.

"We really want the whole kit and caboodle," Ford said.

Vice President of Market Services Adam Keech said the RTO wants to "look more broadly" at potential long-term solutions.

"It's not clear that the MISO/SPP approach that has been proposed [by the Monitor] here is better than what we've proposed and the best option out there," Keech said. "Our reluctance is not knowing whether it's the best answer ... whether it's better than what ERCOT does, for example."

Sotkiewicz said PJM needs to listen "very carefully" to stakeholders' calls for intermediate and long-term changes. He said interest remains in going all the way with pricing changes and not just stopping with the short-term fixes.

"This is a member-driven organization, and just because it might be hard to do doesn't mean we should just be committing to evaluate," Sotkiewicz said. "If it's something that makes sense, we should be committed to do it."

"We do commit to doing the analysis on the options," Keech responded. ■

SPP News

Analyst: Texas ROFR Bill Likely to Survive

By Tom Kleckner

A Texas law giving incumbent transmission companies the right of first refusal to build new power lines in the state will likely survive another round of judicial review, according to one energy analyst.

The 5th U.S. Circuit Court of Appeals last week heard oral arguments in NextEra Energy's effort to repeal the 2019 law but is not expected to rule on the matter for several months (20-50160).

NextEra Energy Capital Holdings, on behalf of four other NextEra transmission owner/developer entities, appealed a U.S. district court's February decision to not overturn Texas *Senate Bill 1938*. (See *NextEra Appeals Court Decision on Texas ROFR Law*.)

The law essentially allows only incumbent transmission companies to build new power lines in Texas by granting regulatory certificates of convenience and necessity to the owners of the endpoints of a new transmission line. NextEra has alleged the law imposes burdens on interstate commerce by restricting entry into Texas' transmission market, "outweighing any local benefits."

ClearView Energy Partners, a D.C.-based independent energy policy research firm, said in a letter to its clients that it believes oral arguments during the June 1 hearing provide SB 1938's proponents a reason to be optimistic.

Judge Jennifer Elrod | *Ballotpedia*

Judge Gregg Costa | *Appellate Academy*

The firm said Judge Jennifer Elrod appeared "skeptical" of NextEra's standing and the "ripeness of the appeal." Judge Gregg Costa "appeared at times to share" that view, it said.

"Judge Costa, however, did offer the view that Texas was not just establishing a right of first refusal … akin to a Minnesota law recently upheld by the 8th Circuit, but rather an outright ban," the firm said.

Costa was referring to a similar case in Minnesota before the 8th U.S. Circuit Court of Appeals. (See *Justice Dept. Joins Challenge to Minn. ROFR Law* and *Courts Uphold Minn. ROFR, MISO Cost Allocation*.)

ClearView also said it considers the upcoming decision to be a "potential indicator of whether other states may see low judicial risk if they consider similar laws."

"The 5th Circuit's ruling could provide additional clarity of how the courts are interpreting the limits the dormant Commerce Clause imposes on states that create in-state preferences or requirements, an issue that has raised judicial risk in the past for state renewable power mandates," the firm said.

NextEra is appealing the decision because it says NextEra Energy Transmission (NEET) Midwest could lose its "lawfully won right" to build the $115 million Hartburg-Sabine Junction transmission project in MISO's East Texas footprint. It says SB 1938 "substantially impaired" NextEra's reasonable contractual expectation to obtain a CCN from the Texas Public Utility Commission, as required by NEET Midwest's agreement with MISO.

NEET Midwest won the project's rights in 2018 through a competitive bidding process. (See *NextEra Wins Bid to Build MISO's 2nd Competitive Project*.)

The legislation also affects NEET Southwest's application with the PUC, the appeal's defendants, to transfer ownership of 30 miles of 138-kV facilities from Rayburn Country Electric Cooperative in SPP's region of East Texas. ■

The 5th Circuit Court of Appeals in New Orleans is weighing NextEra's appeal of Texas' right-of-first-refusal legislation. | *5th U.S. Circuit Court of Appeals*

FERC OKs Basin Electric's Market-based Rates

Empire Granted Separation of Functions Relief

FERC last week approved Basin Electric Power Cooperative's request to make wholesale sales of energy, capacity and ancillary services at market-based rates in its Central and SPP regions, effective June 7, designating the cooperative as a Category 2 seller (*ER20-1505*).

The commission said Basin met its requirement that the co-op and its affiliates lack or have adequately mitigated horizontal and vertical market power.

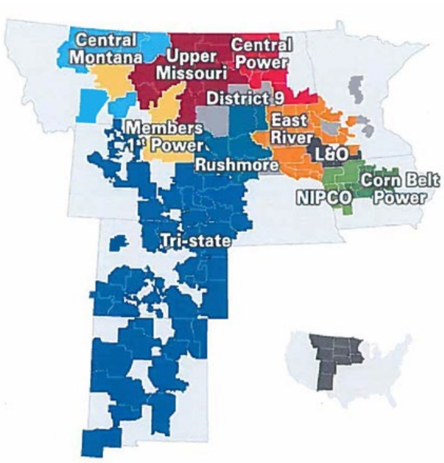
Basin said it has turned over functional control of its Eastern Interconnection transmission facilities in the Central and SPP regions to MISO and SPP, respectively.

Before Nov. 1, 2019, Basin was exempt from commission jurisdiction because its member-owners were public power districts, electric cooperatives that have Rural Utilities Service debt, or electric cooperatives that sell less than 4 million MWh of power annually.

Basin said that it lost its exemption because of two of its owner-members themselves lost exempt status. Tri-State Generation and Transmission Association lost its status when it admitted nonexempt Mieco Inc., a subsidiary of subsidiary of Marubeni Corp., as a member. Upper Missouri G&T Electric Cooperative lost its exemption when it was determined that one of its members was selling more than 4 million MWh of electricity annually.

Basin told the commission it is seeking market-based rate authority only in the Central and SPP regions. It plans to file a second application for MBRA in the other markets in which it operates once it has a Tariff on file with FERC for them.

Empire District service center in Joplin, Mo. | *PGAV Architects*



Basin Electric's service territory encompasses much of the northern Great Plains. | *Basin Electric*

FERC denied Basin's request for a waiver of the minimum 60-day notice requirement, ruling its MBRA would be effective June 7, 61 days after its filing. The commission noted its policy that, absent extraordinary circumstances, it does not grant waivers of notice requirements when an agreement for new service is filed on or after the day service has commenced. However, the commission said it would not require refunds for sales prior to June 7.

The commission also directed Basin to file electric quarterly reports.

FERC defines Category 2 sellers as those entities that aren't Category 1 sellers, which are wholesale power marketers or wholesale power producers affiliated with 500 MW or less of generation in a region.

Empire Gets Waiver for Solar, Wind Projects

The commission also conditionally approved Empire District Electric's request for a waiver to permit designated marketing employees to perform scheduling and related activities for certain Empire affiliates, effective May 1 (*ER20-432*).

The waiver allows marketing employees to perform services for two small solar power production facilities indirectly owned by affiliate Liberty Utilities and three wind-generating projects that will be indirectly owned by Empire.

FERC said its decision relies on "Empire's representations that scheduling and related activities to maximize efficiencies, coordinate scheduling, perform forecasting and other sharing of information will be used to the benefit of captive customers."

Liberty has acquired the 50-MW Luning Solar Energy Center and the 10-MW Turquoise Liberty Project, both in Nevada. Liberty is a direct subsidiary of California utility CalPeco, to which Luning makes power sales.

Empire has signed agreements to acquire indirect and controlling interests in three wind projects with a total capacity of approximately 600 MW: Neosho Ridge Wind, a 301-MW facility planned for Kansas; Kings Point Wind, a 150-MW resource that will be located in Missouri; and the approximately 150-MW North Fork Ridge Wind project, to be built in Missouri.

Empire told the commission that any market information will be shared "with the ultimate goal of maximizing the performance from the wind and solar projects, the benefits of which flow to the captive retail customers of CalPeco and Empire."

The three wind projects will be included in Empire's rate base upon state regulatory approval. The solar projects are in CalPeco's rate base. ■

— Tom Kleckner

Company Briefs

Ameren Missouri Announces Fund to Help Customers Pay Bill Balances

Ameren Missouri last week announced it will provide $3.5 million in additional energy assistance to help thousands of customers who were impacted by the COVID-19 pandemic pay off their past-due utility bills.

Multiple community partners and agencies will participate in the program, which is designed to help income-eligible customers clear their remaining balance after paying off 25% of their current balance.

Ameren has extended its suspension of service disconnections and late fees to at least July 1.

More: *Ameren Missouri*

AMP, OMEA Announce New Director of Gov't Affairs

American Municipal Power (AMP) and Ohio Municipal Electric Association (OMEA) last week announced that Brian Hickman has joined the organizations as director of government affairs. Hickman will manage their advocacy efforts and serve as their primary contact at the Ohio Statehouse.

Prior to joining AMP and OMEA, Hickman served as director of government affairs for the Ohio Oil and Gas Association. Before that, he was a senior legislative aide for state Rep. John P. Hagan (R).

More: *AMP Partners*

CenterPoint Energy Closes Multimillion-dollar Divestment

CenterPoint Energy last week completed the sale of CenterPoint Energy Services (CES), its natural gas retail business, to private equity firm Energy Capital Partners for $286 million.

When the deal was announced in February, it was valued at $400 million. However, the price was adjusted because the estimated working capital was lower than expected, primarily because of "the impacts of changes in commodity prices and impacts related to the timing of close that resulted in less working capital needs at CES."

CenterPoint said it will use the proceeds to pay down debt.

More: *Houston Business Journal*

EPE Acquisition Deadline Extended 3 Months

El Paso Electric and JPMorgan Chase-linked Infrastructure Investments Fund (IIF) on June 1 agreed to a three-month extension of the utility's purchase. The sale was originally to close by June but now has a Sept. 1 deadline.

FERC in March granted conditional approval of IIF's $4.3 billion purchase, pending a mitigation plan to change purchase power agreements related to IIF's ownership of an Arizona power plant. (See *FERC Conditionally OKs JP Morgan's Purchase of EPE*.) The parties filed two proposals in April, but the commission has not yet taken action (EC19-120). The purchase has been approved by all other regulatory bodies in Texas and New Mexico.

Public Citizen in April asked FERC to reconsider its ruling involving JPMorgan and the financial affiliates it is using to fund the purchase. The commission issued a tolling order on May 8 that gives it additional time to respond to the consumer advocacy group's request. (See *Public Citizen Seeks Rehearing of El Paso Electric Order*.)

More: *El Paso Times*

Fifth Third Bank Goes 100% Solar

Fifth Third Bank recently became the first Fortune 500 company to achieve 100% renewable power through solar energy alone and did so via a single project.

The Aulander Holloman solar facility, which spans roughly 1,400 acres in North Carolina, came online last fall and will provide the company with about 200,000 MWh a year.

More: *Yale Climate Connections*

Ocean Current Energy Farm Hopeful 'by Next Year'

The first array of clean-energy turbines drawing power from the fast-flowing U.S. Gulf Stream could be operational next year following trials of three ocean current energy technologies off the Florida coast.

Developer OceanBased Perpetual Energy (OPE) last week carried out three days of tests with the help of Florida Atlantic University's Southeast National Marine Renewable Energy Centre. The tests were run 20 miles off the coast and represent the first time energy has been harnessed from the Gulf Stream for a full 24 hours using "only the water's perpetual flow."

The Department of Energy estimated the Gulf Stream could add up to 45 TWh/year of electricity to the Florida grid.

More: *Recharge News*

Southern's Vogtle Nuclear Plant 'Highly Unlikely' to Meet Deadlines

Don Grace, vice president of engineering for the Vogtle Monitoring Group, last week said Southern Co.'s Vogtle nuclear plant in Georgia is "highly unlikely" to meet state deadlines and is apt to face additional budget overruns.

Grace said the company is no longer on pace to complete the two reactors by the November 2021 and November 2022 deadlines approved by the Public Service Commission and estimated the project's cost would exceed its current $17.1 billion target. The monitoring group said Southern's strategy to speed up COVID-19 testing before finishing much of the construction at the plant led to inefficiency and higher costs.

Jeff Wilson, a spokesperson for Southern's Georgia Power unit, disputed that claim and said Vogtle remains on schedule and budget.

More: *Bloomberg*

Federal Briefs

DOE Headquarters Reopens in Phase 1

The Energy Department's D.C. headquarters reopened for some employees Monday, after Secretary Dan Brouillette last week told employees that a group of "phase one" employees could return.

Phase one employees were defined as those who are "mission-critical personnel whose work is best performed on-site ... including those who are needed to support limited facility operations." Employees who return will receive information and can get virtual training on the safety precautions being taken.

Those who self-identify as "members of certain categories" will be able to continue teleworking. The reopening plan states that those who are medically at-risk or who live with or care for vulnerable people are allowed to remain home for the first two reopening phases.

More: *The Hill*

EPA Limits States', Tribes' Ability to Protest Pipelines, Energy Projects

EPA last week finalized a rule that will restrict the rights of states, tribes and the public to object to federal permits for energy projects that could pollute waterways. The new rule, which will alter the way the Clean Water Act is applied, will set a one-year deadline for parties to certify or reject proposed projects that could discharge pollution into waterways and limit any reviews to include only water quality impacts.

Administrator Andrew Wheeler argued that some states had abused the law in the past, using long delays to trap energy-related projects "in a bureaucratic Groundhog Day" and said the change will give states "more than enough time" to scrutinize proposed projects while preventing them from holding them "hostage" for lengthy periods.

More: *The Washington Post*

House Dems Introduce $500B Green Transportation Infrastructure Bill

The House Transportation Committee last week rolled out a nearly $500 billion infrastructure bill aimed at updating the country's aging transportation system and would offer a significant amount of money toward repairing roads and bridges.

The legislation would also establish new greenhouse gas standards that states must meet, with increased funding going to states that make the most progress. States would also be required to make sure new transportation projects will have a positive effect on climate change.

Transportation is the largest source of greenhouse gas emissions in the country, according to EPA, supplying nearly a third of emissions. Nearly 60% of that comes from cars and light-duty trucks.

More: *The Hill*

Natural Gas Flows Sink to 9-month Low

The amount of natural gas flowing to U.S. LNG plants is on track to fall to a nine-month low of 4.3 Bcfd, data provider Refinitiv said in a preliminary report last week that may be revised.

Analysts said U.S. LNG feedgas has declined because of the recent wave of cargo cancellations after hitting a record in February before most governments imposed COVID-19 lockdowns. Most of the county's feedgas decline was at Cheniere Energy's export plants at Sabine Pass in Louisiana and Corpus Christi in Texas.

More: *Reuters*

US Adds 97.5 MW of Storage Capacity in Q1

A Wood Mackenzie report and the U.S. Energy Storage Association showed the country installed 97.5 MW of storage capacity in the first quarter, which was down by 48% quarter-on-quarter because of a 79% fall in front-of-the-meter installations. Storage deployments are down 39% year-on-year.

"While the ongoing pandemic will more seriously affect Q2, we anticipate year-over-year growth as states have continued to pass regulations and legislation to encourage energy storage deployments," ESA CEO Kelly Speakes-Backman said.

According to Wood Mackenzie and ESA, COVID-19 will not stop the storage market from crossing the $1 billion mark this year, and they expect it to grow to $6.9 billion in 2025.

More: *Renewables Now*

State Briefs

ARKANSAS

PSC Issues Long-awaited Net-metering Ruling

The Public Service Commission last week ruled that the current 1:1 full retail credit for net excess generation will be retained.

Utility representatives argued the 1:1 rate allowed solar-owning customers to dodge paying their share for grid infrastructure and called for a two-channel billing system that would charge one rate for providing power and a lower rate for crediting customers for their excess power. However, the PSC rejected the arguments that the net-metering rate should be closer to the average utilities pay on the wholesale markets and decided to leave rates alone for small systems under 1 MW and for residential rooftop systems. While utilities can seek the grid fee on new projects after the ruling, the PSC will grandfather in announced projects at the current rate structure.

The commission said it will consider requests for grid charges starting in 2023 for systems above 1 MW.

More: *Arkansas Business*

CALIFORNIA

3 Killed When Helicopter Hit Power Line

Three people contracted by Pacific Gas and Electric were killed when a helicopter struck one of the utility's power lines and crashed into a Northern California hillside June 2. The crash also ignited a grass fire and knocked out electricity to thousands.

The crash of the Bell 206 helicopter was reported about 1:30 p.m. along Interstate 80, midway between Fairfield and Vacaville.

More: *The Associated Press*

COLORADO

Colorado Springs Utilities Prepares for Carbon Reduction

The Colorado Springs Utilities' Policy Advisory Committee last week voted unanimously to recommend an energy mix to the Colorado Springs City Council that would reduce carbon emissions by 80% by 2030 and end all coal-fired production at the Martin Drake Power Plant by 2023.

The council also serves as the utility's board and will review the committee's recommendation on June 26. The board is expected to select an energy mix that will determine the timeline for the closure of coal generation at Drake and the Ray Nixon Power Plant. To comply with state law, the board must select a future mix that will cut the utilities' carbon emissions 80% by 2030 from 2005 levels. To reach that goal, the company must end coal generation at Drake and Nixon by 2030 and replace the 400 MW with other sources.

More: *The Gazette*

DISTRICT OF COLUMBIA

District did not have City-wide Blackout on June 1

NetBlocks.org, which tracks disruptions and shutdowns of networks, tweeted that it found "no indication of a mass-scale internet disruption overnight or through the last 48 hours" in the nation's capital on June 1.

PEPCO did not release any statements about a blackout but later confirmed there were no outages in the district during the night in question. Furthermore, AlertDC, a communication system that delivers emergency alerts, did not release an alert for a power outage of any kind.

The confirmations are in response to claims that the city experienced a blackout in which electricity, internet and cellular communications were suspended in the early hours of June 1. The claims came amid protests against police brutality.

More: *Reuters*

IOWA

ISU to Replace Coal Boilers with Natural Gas

Iowa State University (ISU) last week said it is looking to spend between $12 million and $14 million to replace its two remaining coal-fired boilers with natural gas-fired boilers and effectively end the campus' use of coal.

Although the university plans to pay for the project using utility funds, administrators expect to make the money back in less than four years "through annual utility savings of $3.7 million derived from this project." In addition, the replacement would reduce the university's greenhouse gas emissions by 35%.

The proposal does not include a timeline for construction to begin, as ISU is seeking regent approval to proceed with the planning of the project.

More: *The Gazette*

MAINE

PUC Rejects CMP's Virus Relief Fund Plan

The Public Utilities Commission last week rejected Central Maine Power's proposal to set up a $500,000 fund to help customers harmed by the COVID-19 pandemic pay their bills. The PUC said the plan was well intended but not well targeted.

The fund, which would have been paid for by CMP shareholders, was part of a settlement reached between the company and the Public Advocate's Office regarding the way CMP notified customers about its winter disconnection practices since 2015. The commission said the proposal fell short of public-interest legal requirements and wondered whether the money for those impacted by the pandemic would help the same people who received the disconnection notices.

The PUC lawyer overseeing the case will next decide how to proceed.

More: *Portland Press Herald*

MICHIGAN

Consumers, DTE Energy Extend Shutoff Protections

Regulated utilities Consumers Energy and DTE Energy last week said their shutoff protections, flexible payment plans and other options for the COVID-19 pandemic will continue through June 12.

The Public Service Commission has directed electric and natural gas utilities to file affirmations they will put customer safeguards in place.

More: *9&10 News*

DTE Expresses Concerns over Ann Arbor's Renewable Energy Plan

As the Ann Arbor City Council two weeks ago voted to adopt the A2Zero plan, a proposal for the city to achieve carbon-neutrality by 2030, DTE Energy Marketing Director Henry Decker raised concerns about the community choice aggregation part of the plan and suggested other alternatives.

The first concern was the community choice aggregation, which could allow the city to buy energy from other providers. The second relates to the city wanting to shift away from natural gas with building code changes.

Decker said DTE reviewed the city's plan, and there are opportunities for the two to partner, such as "developing a customized renewable electricity solution that promotes renewables in Michigan directly attributable to Ann Arbor, including community renewable projects such as solar and wind."

More: *MLive*

State Pays $7M to Keep Utilities Going

The Department of Health and Human Services last week said it made payments totaling $7 million to maintain utility services for nearly 18,000 households that are having trouble paying bills during the COVID-19 pandemic.

The payments all were made on behalf of households that have past-due accounts and were facing shutoffs this month. The payments, which averaged $395, came from the Low-Income Home Energy Assistance Program and went to Consumers Energy, DTE Energy and SEMCO Energy. With the payments, the three utilities agreed to waive $2.3 million worth of outstanding balances.

More: *WJRT*

NORTH CAROLINA

Dominion Pipeline Along Tobacco Trail Will not be Built

Dominion Energy last week announced it had decided not to build a natural gas pipeline along a stretch of the American Tobacco Trail in Chatham, Durham and Wake counties. The utility said it still plans to construct a 13-mile pipeline from Wake to Durham but has ruled out seeking an easement along the famous trail.

Dominion had approached the Department of Transportation about acquiring an easement that would allow it to build and operate a 12-inch pipeline along the trail from Morrisville Parkway in Cary through Chatham County to Scott King Road in Durham. The department agreed to grant the easement for a one-time payment of $3 million but said the details of the agreement had not been worked out.

Opponents organized to fight the pipeline, although Dominion spokeswoman Persida Montanez said the public opposition was not a factor in the decision to rule out the route.

More: *The News & Observer*

TEXAS

State Heads into Summer with Larger Reserve than 2019

Texas will head into summer with a 10.6% reserve margin, which is 2% higher than it was last year, according to ERCOT. Still, the margin is still less than the grid operator's goal of 13.75%.

ERCOT believes Texas will set usage records during peak times this summer and shatter last August's record when a more than 100-degree Fahrenheit heat wave encompassed most of the state. State generators profited from last summer's heat wave because regulators allowed them to charge higher prices during times of extreme demand. The Public Utility Commission has once again given generators permission to charge more, making it likely that prices will rise higher and faster during times of great demand and tight supply. A larger reserve, however, could hold down wholesale prices.

More: *Houston Chronicle*

WEST VIRGINIA

Murray Energy Projects Thousands of Layoffs

Six Murray Energy subsidiaries on May 28 filed mass layoff notices with WorkForce West Virginia covering 2,453 employees and operations in Ohio, Marshall and Marion counties. The filings pointed to June 17 as the projected date for the layoffs.

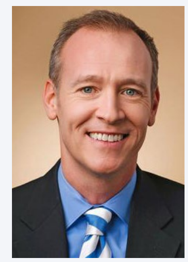
Murray, the largest privately owned coal company in the U.S., filed for Chapter 11 bankruptcy protection last October while facing more than $8 billion in potential and actual legacy liabilities and $2.7 billion in outstanding funded debt obligations.

More: *The Herald-Dispatch*

WISCONSIN

We Energies Building Sustains Millions in Damage from Tunnel Floods

We Energies' headquarters in Milwaukee sustained more than $10 million in damages when a system of underground steam tunnels flooded during a major rainstorm two weeks ago.



Spokesman **Brendan Conway** said the company will have to replace computers and other electronic equipment, carpeting, cubicle partitions and furniture that became wet. Ceiling tiles, wallpaper and light fixtures also sustained damage.

Ted Sniegowski, WE's manager of steam services, said there were two breaches in the steam tunnels: one at the tunnel entrance at the company's Public Service Building, and the other in the West Michigan Street tunnel. The company has not yet determined the source of the water.

More: *Milwaukee Journal Sentinel*