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 33 August 18, 2020

CAISO Blames Blackouts on Inadequate Resources

ISO Orders Stop to Controversial Convergence Bidding

By Hudson Sangree and Robert Mullin

CAISO on Monday blamed inadequate preparation by others for a supply shortfall that caused rolling blackouts over the weekend during the Western heat wave.

During an emergency meeting of the Board of Governors, CEO Steve Berberich immediately jumped to the defense of the ISO, which received the brunt of criticism for ordering the statewide rolling blackouts Friday and Saturday.

The California Public Utilities Commission authorizes load-serving entities to procure energy, he said. CAISO has told the CPUC that an additional 4,700 MW would be needed to meet summer peaks during the state's transition from fossil fuels to renewable energy. The CPUC directed LSEs to procure a total of 3,300 MW by next year, when the shortfall is expected to grow worse, he noted.

"The ISO does not direct procurement. We are the system operator," Berberich said. "The situation we are in could have been avoided. For many years, we have pointed out to the procurement-authorizing authorities that there was inadequate power available during the [evening] net peak," after solar has left the system but demand remains high.

The weekend outages occurred as solar power waned, he said. About 12,000 MW of battery storage are needed to store renew-

Continued on page 5

FERC Accepts PJM TOs' End-of-life Revisions

By Michael Yoder

FERC on Aug. 11 accepted PJM Transmission Owners' Tariff amendments governing end-of-life (EOL) projects, a proposal that was hotly contested by stakeholders (*ER20-2046*).

The TOs had proposed to identify and include asset-management projects within the existing planning procedures of Tariff Attachment M-3 and to include procedures for the identification and planning for EOL needs of transmission lines 100 kV and above.

The TOs voted in June to approve a Federal Power Act Section 205 filing of the proposed *amendments* through voting procedures contained in the Consolidated Transmission Owners Agreement (CTOA). (See *TOs Vote to File End-of-life Rules with FERC*.)

Stakeholders challenging the filing asserted that the TOs do not have "exclusive filing rights" in regard to EOL projects and that PJM members maintain rights under the Operating Agreement to also make filings related to EOL projects. A competing, joint stakeholder *proposal* is still pending before FERC (ER20-2308). (See *PJM Files EOL Proposal over TO Protest*.)

"Given the specific facts and circumstances before us, we find that the planning activities addressed by the Attachment M-3 revisions filing are within the exclusive rights and responsibilities retained by the PJM TOs under the CTOA," the commission said in its ruling. "Under the CTOA and the Tariff, the PJM TOs retain all rights that they have not specifically granted to PJM."

TO Filing

The new rules will require TOs to have a formal process for EOL determinations and to identify potential EOL projects five years in advance. Projects that "overlap" with Regional Transmission Expansion Plan (RTEP) violations will be included in a competitive window seeking regional solutions.

Continued on page 24

Maine Court Rejects Referendum on Tx Project

By Rich Heidorn Jr.

Maine's Supreme Judicial Court removed a major obstacle to the New England Clean Energy Connect (NECEC) transmission line Thursday, *ruling* that a proposed voter initiative on the project is unconstitutional.

Ruling on a challenge by Central Maine Power and parent Avangrid Networks, the court said the ballot question improperly intruded on executive branch authority in seeking to reverse the Maine Public Utilities Commission's 2019 order granting the project a certificate of public convenience and necessity. Maine's constitution, the court said, only allows citizens' direct initiatives to propose "legislation."

The decision reversed a lower court decision that said it was not necessary to determine the constitutionality of the referendum before the vote.

Continued on page 11

Also in this issue:

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

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

Deputy Editor / Daily
Michael Brooks
301-922-7687

Deputy Editor / Enterprise
Robert Mullin
503-715-6901

Art Director
Mitchell Parizer 718-613-9388

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 Manager
Kathy Henderson 301-928-1639

Account Manager
Phaedra Welker 773-456-4353

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

CAISO/West News

Calif. to Stay Course on Electrification, CEC Chair Says

Lawsuit by SoCalGas Latest Effort to Keep Natural Gas in the Mix

By Hudson Sangree

The California Energy Commission will stick to the path of electrifying buildings despite a legal challenge filed against it by the nation's largest natural gas utility, the agency's chair said Wednesday.

"Directionally, at the Energy Commission, we are going to keep fidelity to the state's goals" of reducing greenhouse gases, including by electrifying buildings, increasing energy efficiency and procuring renewable energy, as required by landmark laws and executive orders signed by former Gov. Jerry Brown, Chair David Hochschild said.

"And along with that, we do care a great deal … about health," Hochschild said. "And one of the things that recent research has uncovered is that the health impacts, even among homes that have gas, that have the same appliances, are not equal. Low-income homes are more likely to have heavier burdens" because they lack adequate ventilation for emissions from gas appliances, he said.

Hochschild made his remarks after hearing from dozens of environmental activists, physicians and residents who called for the CEC to require new buildings in California to be all-electric starting with the commission's 2022 update to its building energy efficiency standards, which it plans to approve next year. Many of the speakers cited health impacts associated with methane emissions.

Local Electrification Measures

Cities and counties can pass ordinances that exceed the 2019 standards with the CEC's approval. Nearly three dozen local governments have done so by requiring new or existing buildings to have electric furnaces, water heaters and cooktops in place of gas appliances.

San Luis Obispo was the latest city to adopt an electrification measure. On Wednesday, the CEC approved a city ordinance requiring all new buildings to be electric or, if using mixed fuels, to achieve heightened energy efficiency standards.

The CEC also approved a Davis city ordinance mandating rooftop solar and increased efficiency standards for high-rise and nonresidential buildings. State law already requires rooftop solar on new low-rise residential structures, though the CEC has approved exceptions to the rule. (See *Calif. Energy Commission Relaxes Rooftop Mandate*.)

Nearly all the public speakers at Wednesday's hearing began by backing the proposed city ordinances but quickly segued into calling for statewide electrification rules.

SoCalGas Lawsuit

Hochschild acknowledged the comments and said the CEC would stay the course on electrification even though "now [the effort is] going to continue in court, because [Southern California Gas] elected to sue us … over this issue."

SoCalGas, which serves nearly 22 million customers, filed a lawsuit in state court July 31 arguing that the CEC had failed to consider natural gas as a cleaner alternative to other fossil fuels, as it was required to do by a bill Brown signed in 2013.

"Natural gas and renewable gas are clean, affordable, resilient and reliable sources of energy on which millions of California consumers and businesses depend," the company said in its lawsuit. "Natural gas has played a significant role in reducing greenhouse gas emissions and improving air quality, and natural gas and renewable gas remain critical to meeting California's energy goals."

The move was the latest pushback by natural gas companies concerned that California's environmental and energy regulations will leave their assets stranded and worthless in the coming decades.

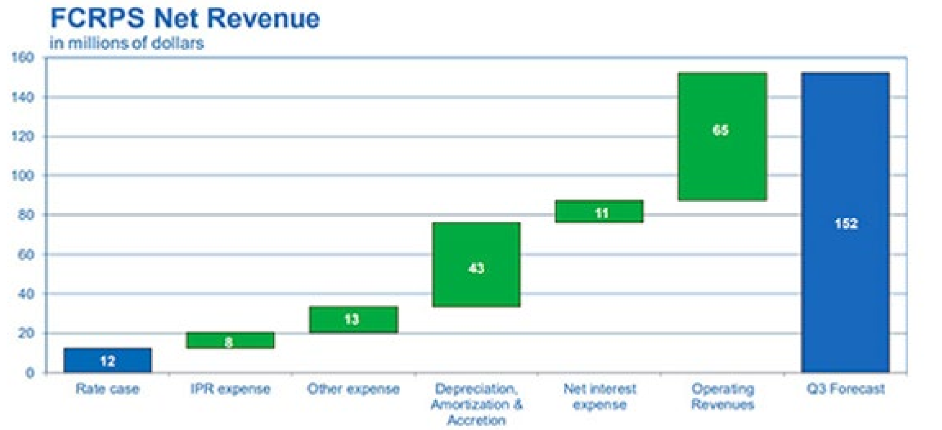
Senate Bill 100, signed by Brown in 2018, calls for load-serving entities to provide 100% carbon-free energy to retail customers by 2045. An executive order by Brown requires the state to achieve carbon neutrality by 2045.

In addition to legal challenges, gas companies are advocating for their pipelines to carry up to 30% hydrogen produced using excess renewable energy. (See *NARUC Panel: 'Green' Hydrogen Could Lower GHGs*.) ■

CAISO/West News

BPA Poised to Weather COVID Impact

By Robert Mullin



BPA now expects its FY 2020 net income to hit $152 million, far exceeding the rate case figure of $12 million and a Q2 pandemic "bad case" scenario of $44 million. | *BPA*

The COVID-19 pandemic is having little impact on Bonneville Power Administration operations or financial health, with fiscal year 2020 net income projected to easily exceed a "bad case" scenario outlined last quarter, agency officials said last week.

"Even though we've had some unusual times, with disciplined cost management and favorable market conditions, we are forecasting hitting all of our financial targets for this year," CFO Michelle Manary said during BPA's third-quarter business review. (The federal power marketing administration follows an October-September fiscal calendar.)

Having weathered a highly uncertain third quarter, BPA now forecasts fiscal year net income could hit $152 million, up sharply from a second-quarter "baseline" case prediction of $110 million and well above the pandemic worst-case figure of $44 million. The latest estimate also puts BPA far ahead of its rate case target of $12 million for the year, Manary noted.

While reduced expenses account for some of the increase, the largest share stems from a big boost in net operating income, which is predicted to ring in at $65 million, compared with the $8 million estimate in the second-quarter outlook.

"This increase comes from power [generation], with higher secondary sales" of surplus power, Manary said. "Secondary sales have benefited from higher market prices and a good runoff pattern. Shape is everything," indicating that hydroelectric surpluses happened to coincide with intervals of higher demand.

"While we're seeing local reductions with certain customers due to COVID-19, we're seeing increases in other areas, with a net result of no drop in aggregate load," she added.

BPA's power generation business is expected to yield more than $2.76 billion in total revenues, compared with the rate case estimate of $2.71 billion. That business line is also projected to incur expenses of nearly $2.6 billion, about $65 million below the rate case, in part because of delays in fish and wildlife project work stemming from social distancing measures. An amortization accounting adjustment related to the Columbia Generating Station nuclear plant in Washington state will additionally reduce expenses from the rate case level.

"These reductions were partially offset by power purchases, which were higher than rate case due to higher spill conditions that took place this summer. We saw average inventory in water … but we're spilling at higher levels," Manary said.

BPA's transmission business should take in revenues of about $1.085 billion, just a million shy of the rate case. At nearly $1.01 billion, transmission expenses are projected to be about $25 million below the rate case, "primarily driven by lower interest rates and capital spending," Manary said.

The latest FY 2020 capital expenditure forecast of $613 million is below the second-quarter baseline forecast of $656 million (and well below the rate case estimate of $847 million), but "substantially higher" than the COVID-19 "bad case" of $412 million "due to a restart of our capital program in June. We basically saw only a $20 million hit from COVID throughout the capital program," she said.

Last Waltz for Mainzer

BPA also took steps early this summer to relieve the economic burden on its customer base of publicly owned utilities, including suspending collection of a surcharge implemented last year to buttress its financial reserves. That move is expected to save those utilities a combined $3 million per month for the rest of this fiscal year and a total of $30 million next year.

"At Bonneville, we remain very sensitive to the economic challenges facing our customers — and the communities they serve — as a result of the pandemic," BPA Administrator Elliot Mainzer said. "We truly understand the hardship and uncertainty that many of you are facing."

Mainzer said BPA would also "streamline" the process by which its customer utilities can request payment extensions if they're facing financial hardship from the pandemic.

"This is not a waiver of the bill, but it extends the payment out, with interest, for up to three years," he said.

Mainzer noted that the "vast majority" of staff continue to work from home in light of the pandemic and will continue "to do so for the foreseeable future," while field staff are ramping up their work "consistent with social distancing requirements."

"While we have not had any interruptions to service delivery, the coronavirus numbers in our service territory have remained challenging, and we've asked our workforce to be ever diligent in protecting the health and safety of their co-workers and their families," he said.

The quarterly review Aug. 11 was the last for Mainzer, who will depart BPA at the end of August to take over the helm at CAISO in October. (See *CAISO Names Bonneville Administrator as New CEO*.)

"I hope you've found these meetings to be informative and useful as we've defined clear metrics for BPA's business performance and hold ourselves accountable to you for delivering results," Mainzer said. "I know that Michelle and our leadership team are committed to this process going forward and will stay connected as we evolve and progress together. I'd like to thank you for all of your support along the way." ■

CAISO/West News

CAISO Blames Blackouts on Inadequate Resources

Continued from page 1

able energy, along with an "overbuild" of solar and wind generation to charge the batteries, he said. There's currently only 200 MW of storage on CAISO's grid.

Hotter summers caused by climate change also need to be taken into account, Berberich said.

"We have indicated in filing after filing after filing that the resource adequacy program was broken and needed to be fixed," he said. "That program requires the load-serving entities to only procure to a 50/50 weather forecast. That is the worst weather you might have on average 50% of the time — not to an extreme heat storm like we have now.

"Resource adequacy must be reformed so that every hour of the year is properly resourced," he said.

The CPUC rejected Berberich's argument that it was mainly to blame.

"This is a shared responsibility, and we are working with our sister agencies to better understand why this occurred," spokeswoman Terrie Prosper said in an email. "Our current focus is the public's safety and to emphasize the importance of energy conservation to reduce the strain on electric supply."

Demand during the heat wave was in line with predictions and should have been manageable, Prosper said.

"The electricity demand of the last few days is consistent with the level the agencies have for August, and the utilities and community choice aggregators procured the resources that were required to meet the forecasts," said. "The question we're tackling is why certain resources were not available."

Millions Could be Without Power

CAISO predicted even worse outages Monday and Tuesday than those that roiled the state last week. (See *CAISO Warns Blackouts Could Continue, Calls Emergency Meetings*.)

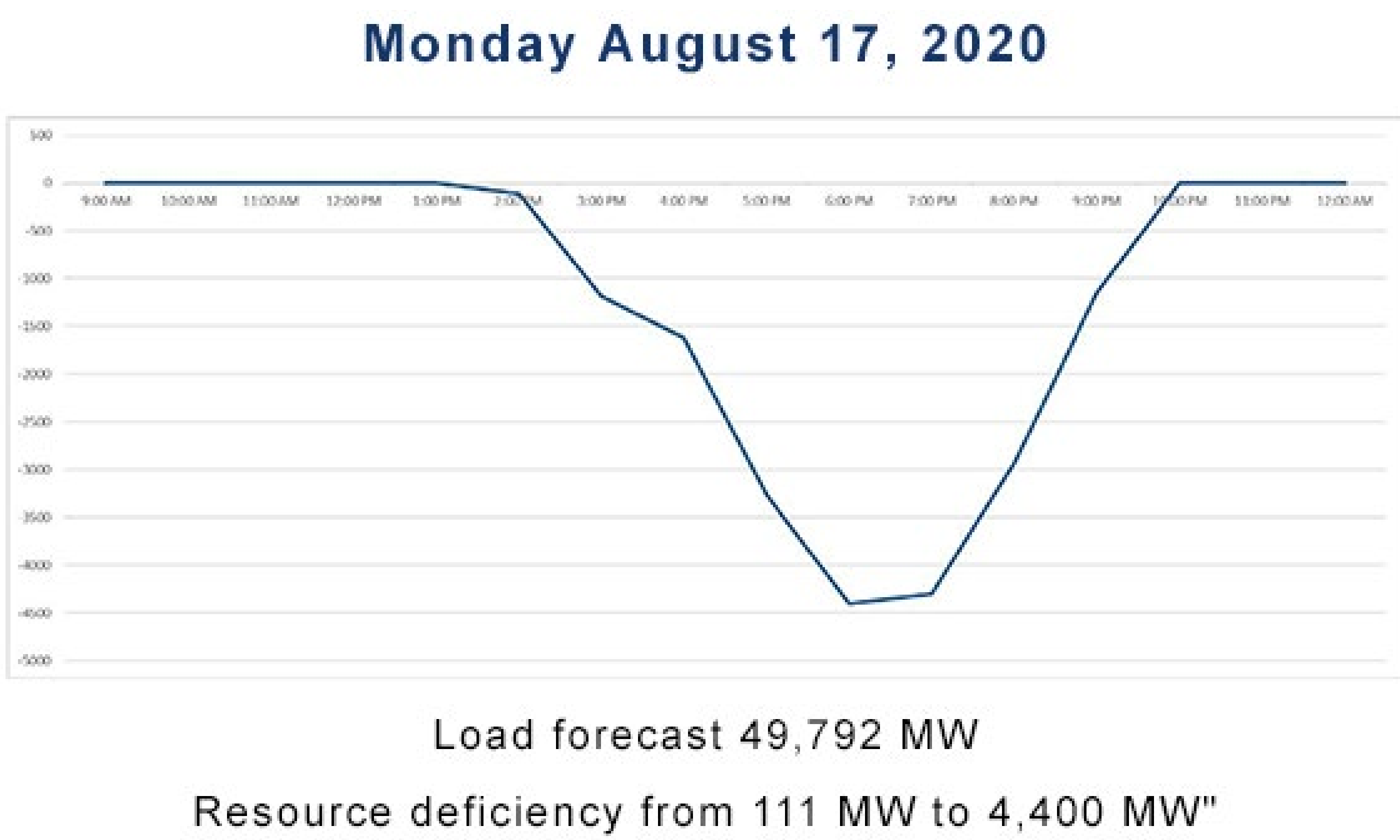
It had predicted up to a 4,400-MW shortfall Monday, with rolling blackouts in the afternoon, increasing after sunset. About 3 million customers could lose power, Berberich acknowledged in a call with reporters.

"We have a perfect storm going on here," Berberich said. "The entire region ... is extremely hot. We can't get the energy we'd normally get from out of state because it's being used to serve load natively."

On Monday night, however, CAISO lifted a Stage 2 emergency declaration, *saying* "no rotating power outages are anticipated, thanks to reduced demand due to consumer conservation and cooler-than-expected weather." The ISO had not updated its predictions for Tuesday as of press time.

The ISO can't dip deeper into its contingency reserve, which can total thousands of megawatts, because the reserve is necessary to protect the Western grid from failure, CAISO officials said.

John Phipps, director of real-time operations, said CAISO must follow NERC and WECC standards that protect the Western Interconnection from failure should a large generator



CAISO predicts resource deficiencies of up to 4,400 MW this week. | *CAISO*

CAISO/West News

CAISO Blames Blackouts on Inadequate Resources

drop offline or another serious problem occur.

CAISO contains 35% of the load in the interconnection, which stretches from the Rocky Mountains to the Pacific Ocean and into Canada and part of Mexico. A serious disruption in the ISO could prove disastrous to the entire area, Phipps said.

Governor Weighs in

During a televised address Monday to California residents, Gov. Gavin Newsom noted the record-setting heat that set the stage for the blackouts but acknowledged the state's ultimate culpability for the crisis.

"Let me just make this crystal clear," Newsom said. "We failed to predict and plan for these shortages, and that's simply unacceptable. I am the governor. I am ultimately accountable and will ultimately take responsibility to immediately address this issue and move forward to make sure this simply never happens again here in the state of California."

Newsom said his office had launched an investigation into the "interrelationship" among CAISO, the CPUC and the California Energy Commission, which he said have a "shared responsibility" to maintain reliable electricity delivery.

"We'll get to the bottom of it, and that's why that investigation into what happened and its implications for the future will be done swiftly and immediately, and we will lay out in detailed terms what we are going to do to make sure this simply doesn't happen again," he said.

In the meantime, the state is "working with partners across the spectrum" to alleviate the immediate energy shortages, including reducing consumption at the state's ports, allowing utilities to tap resources reserved for public safety power shutoffs from wildfires, and procuring more power from the Los Angeles Department of Water and Power (LADWP) and the State Water Resources Control Board, the governor said.

Newsom also called for a broader examination of how California will continue to reliably serve electricity customers while pursuing its ambitious renewable energy and decarbonization targets. State law requires all LSEs to supply 100% carbon-free energy to retail customers by 2045.

"We now have to sober up to the reality that in this transition, we're going to have to do more and be much more mindful in terms of our capacity to provide backup [energy] and insurance," he said.

Convergence Bidding

In a move signaling that its own market mechanisms might be contributing to its real-time shortfalls, CAISO on Sunday notified market participants that it would suspend convergence bidding throughout its footprint beginning Monday (for the Aug. 18 trading date).

"As a result of the record-breaking heat wave that has led to load curtailments, the California ISO has determined that convergence bidding is detrimentally effecting the ISO's ability to maintain reliable grid operations," the ISO wrote in a market notice.

> **"Their 15% reserve margin should have handled this easily."**
>
> —Robert McCullough

Convergence — or virtual — bidding allows market participants to hedge their physical positions and limit exposure to day-ahead and real-time price differentials. The bid is a purely financial one, implying no obligation to take or deliver electricity. Instead, a market participant buys or sells "virtual" energy in the day-ahead market, a position required to be automatically liquidated in the opposite direction in real time.

CAISO said Monday that it had eliminated convergence bidding to give it a clearer picture of day-ahead market conditions. But the practice has a checkered history in California.

A week after implementing convergence bidding at interties into California in February 2011, the ISO suspended bids at nodes on nine interties linked to the Mountain West because of a software glitch that risked overscheduling those points in the physical day-ahead market.

That incident was followed months later by the more serious discovery that some CAISO market participants were using virtual supply bids on the interties to offset virtual demand bids at nodes located just inside the state, a gaming strategy that produced no benefit for the physical market and cost the ISO more than $50 million.

The scheme prompted CAISO to suspend intertie convergence bidding altogether, and it completely eliminated the bidding at interties in March 2016. (See *FERC Eliminates Intertie Convergence Bidding in CAISO*.)

Robert McCullough, an energy economist who was among the first to spot the market manipulation behind the Western energy crisis of 2000/01, pointed to why the convergence bidding market that still exists inside the CAISO remains "worrisome."

"By allowing node-level bids and not requiring physical assets, this allows any single party the ability to dominate transactions at a specific location. Enron called such exploits 'load shift,'" McCullough told *RTO Insider*. "However, that exploit required lying to the ISO about the 'virtual' supplies. The convergence market doesn't even require a lie — just a willingness to gamble on the ISO's computer systems. Past experience has tended to make this less of a gamble than you might think since critical information is often learned by specific market participants and then used to advantage."

McCullough, long an outspoken critic of organized electricity markets, questioned how Friday's unforeseen demand could have sent CAISO into a Stage 3 emergency.

"Their 15% reserve margin should have handled this easily," he said. "The congestion data indicates that this is a Southern California issue, although, mysteriously, LADWP was not affected."

CAISO's demand peaked at 46,777 MW on Friday, above the 1-in-2 peak forecast of 45,907 MW in the ISO's 2020 Summer Loads and Resources Assessment, but below the 1-in-5 (47,755 MW) and 1-in-10 (48,457 MW) forecasts. That assessment also estimated a 3.7% probability the ISO would enter Stage 2 operations this summer and a 1.1% probability for Stage 3.

CAISO on Sunday also declared a capacity procurement mechanism (CPM) significant event to solicit any available resources not already offered into the CPM's competitive solicitation for August. Resource owners were urged to contact the ISO if they were willing to accept its soft offer cap of $6.31/kW-month. CAISO will give preference to resources able to deliver energy from 2 to 10 p.m. ■

ERCOT News

Texas PUC to End COVID Relief Program

Texas regulators last week agreed with their staff's recommendation to end a moratorium on retail customers' cutoffs for nonpayment at the end of September.

Public Utility Commission staff filed a *memo* that recommended enrollment in the commission's COVID-19 Electricity Relief Program halt on Aug. 31 and that the benefits end on Sept. 30 (*50664*).

"This is a hard balance to have, but I think it is the time," PUC Chair DeAnn Walker said during the commission's open meeting Thursday.

The PUC created the program in March to help retail providers' unemployed customers by shielding them from disconnections for nonpayment and offering bill payment assistance. The program is funded by a charge applied to customer bills within the ERCOT region.

A separate requirement to provide customers a deferred payment plan upon their request will continue, Walker said.

"The people who have been on the relief program will be transitioning off and may need to have that opportunity," she said. "I still view … that we're in a state of emergency."

PUC Chair DeAnn Walker opens the Aug. 13 open meeting.

Texas on Friday became the third state to record 10,000 deaths from the coronavirus. The state has more than 545,000 confirmed cases and registered a spike of 6,755 cases the same day as the PUC's open meeting.

In other actions, the PUC:

- fined Reliant Energy $100,000 for failing last year to maintain and produce verification of 292 switch requests and for failing to energize 33 customers on the agreed service start dates, resulting in a loss of service. The utility agreed to change its processes for using third parties to enroll customers (*51045*).
- approved a $39.4 million fuel refund for Southwestern Public Service. The refund had been authorized in April on an interim basis (*50556*). ■

— Tom Kleckner

ERCOT Board of Directors Briefs

Sneak Peek: Passport Program to Integrate Major Projects in 2024

ERCOT is facing a collision of major system changes in 2024 when a new energy management system (EMS), real-time co-optimization (RTC) and energy storage and distributed generation resources will all be brought together.

If handled correctly, ERCOT "will have as modern a system as operated by anyone in the world, by a fair amount," CEO Bill Magness told the Board of Directors on Aug. 11.

Under the Texas grid operator's Passport Program, staff and stakeholders will bring an upgraded EMS online in June 2024. At the same time, they plan to incorporate the work currently being done by the Real-Time Co-optimization and Battery Energy Storage task forces. They will also add solutions for energy storage resources (ESRs) and distributed generation resources (DGRs).

Passport may not be on the same scale as the *Nodal Program* market redesign, which lasted more than four years, involved hundreds of contractors and cost hundreds of millions of dollars. When it was all over in 2010, nodal replaced ERCOT's zonal market structure with a more granular structure comprising more than 8,000 resource nodes.

"This is a multiyear effort that's going to require strong coordination," Magness said. "One of the challenges [in] the next few years … will be resources. Some of these systems will need changes, and there are only so many people who can do coding."

The program's immediate focus is to complete the market rules for RTC and ESRs this year "so we can hit the ground running in 2021 writing the requirements," he said.

The Passport Program will be more broadly communicated to stakeholders in September during ERCOT's annual strategic planning sessions with the membership segments.

Unaffiliated board member Peter Cramton said Passport's integrated approach to delivering the various projects is important, as the projects are interrelated and should be treated holistically.

"In June 2024, ERCOT should be in a position to be leading the world in modern electricity markets," he said.

Peak, Wind, Solar Records as Load Returns

Magness told the board that load has begun to return to pre-COVID-19 levels as evidenced by increased energy usage in June and July.

Usage in June was nearly 1% higher than June 2019 and usage in July was up 2.7% when compared to July 2019. ERCOT set a new

ERCOT News

ERCOT Board of Directors Briefs

monthly peak demand on July 13 at 74.3 GW, breaking the previous mark of 73.5 GW.

Demand in the grid operator's West Texas zones has also reached record levels, Magness said during his CEO's report. The Far West and West zones exceeded prior summer peaks by 7% and 9%, respectively, during mid-July.

ERCOT also set records for wind and solar generation during June and July. Wind production reached a peak of 21.4 GW on June 28, while solar production topped out at 3.7 GW on July 3. The grid operator has added an additional 3.2 GW of wind and solar nameplate capacity since last summer.

"We're really starting to see the impact of [utility-scale] resources," Magness said. He noted that prices were $25 to $33/MWh during the July peak, reflecting a lack of scarcity pricing.

He said ERCOT will continue to produce *COVID-19 load impact analyses* through September, even though they've "kind of hit a groove."

Hurricane Hanna inflicted "significant damage" in South Texas "that could have been worse" when it made landfall on July 24, damaging 30 138-kV and 69-kV lines, Magness said. He said American Electric Power's Wade Smith, an ERCOT director, told him the night before the board meeting that AEP had restored a critical 138-kV transmission line several days ahead of schedule.

"The lines were basically lying on the ground," Magness said. "What AEP did, in the heat of August, in the [Rio Grande] Valley, with COVID, was really remarkable."

COVID-19's effects have led to a $9 million drop in system administration fees. Combined with a $15.9 million negative variance in interest expense, a timing issue "that is going to save us in the long term," ERCOT is currently facing a $28 million year-end negative variance, Magness said.

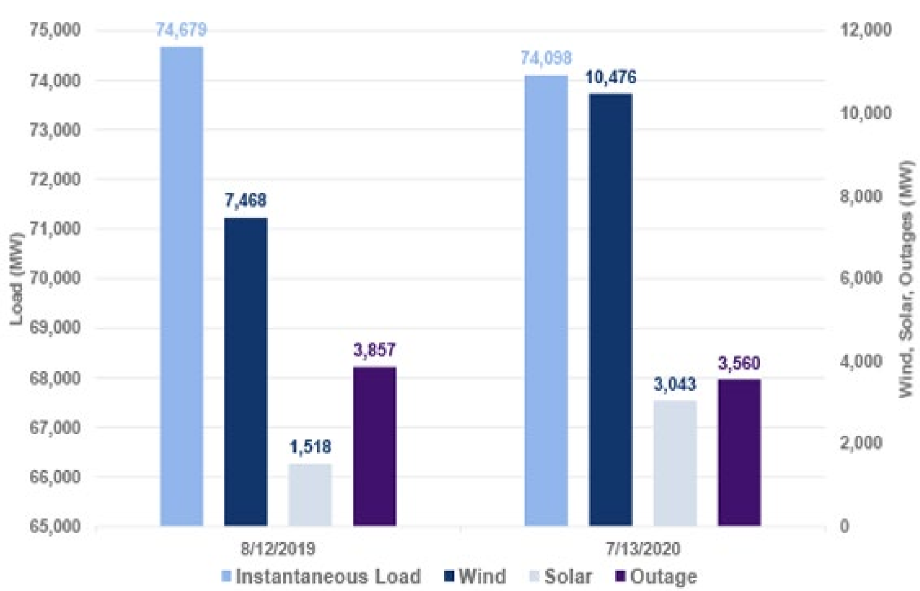
Retired DC Tie's Load Zone Removed

The board approved staff's recommendation to delete the recently retired Eagle Pass DC tie's load zone in South Texas.

The DC tie began a forced outage in March. AEP, the tie's owner, told ERCOT in April that it was permanently removing the tie from service because replacement parts were unavailable. The grid operator has since stopped approving injections onto the tie.

ERCOT's protocols require a 48-month waiting period before a load zone can be removed. Staff are considering sponsoring a Nodal Protocol revision request (*NPRR1017*) to remove the board's required approval and aligning DC-tie load zone deletions with the timeline for removing resource nodes.

The DC tie remains a settlement point for congestion revenue rights (CRRs) through 2022.



Wind and solar energy, diminished during 2019's all-time peak (left), played a major role in helping ERCOT meet its July record peak (right). | *ERCOT*

Direct Energy's Ross Voted onto Board

Board Chair Craven Crowell said Direct Energy's Ned Ross has been elected to replace Rick Bluntzer as the Independent Retail Electric Provider segment's representative on the board. Bluntzer resigned from the board effective July 31.

Infinite Energy's Steve Madden was elected to replace Ross as the segment's alternate.

Consent Agenda Includes 35 Changes

The directors unanimously approved 34 revision requests and *ERCOT's methodologies* for determining minimum ancillary service requirements on its consent agenda.

The latter change simply removes the use of the Resource Asset Registration Form (RARF) with more general language. A Resource Definition Task Force recently completed a three-and-a-half-year review of ERCOT's definitions that resulted in several protocol changes.

The Resource Integration and Ongoing Operations (RIOO) function will replace the RARF, enabling market participants to electronically review and edit existing resource asset registration data. By the end of next year, ERCOT hopes to be able to add ESRs and DGRs to the RIOO.

The package of changes came with individual costs as high as $1.3 million.

"We feel like we're in good shape financially with the implementation of these over time," Magness said. "It's not an issue of running out of money for this, but the buckets are getting full, and we have to make priorities."

The changes included 15 Nodal Protocol revision requests (NPRRs), six changes to the Nodal Operating Guide (NOGRRs), a pair of Other Binding Document revisions (OBDRRs), five changes to the Planning Guide (PGRRs), three revisions to the Resource Registration Glossary (RRGRR), a system change request (SCR) and two changes to the Verifiable Cost Manual (VCMRR).

- *NPRR903*: Clarifies the deviations that may occur with day-ahead market (DAM) delays and adds language requiring ERCOT to issue a market notice for any act or omission to ensure the DAM process is successfully completed.

ERCOT News

ERCOT Board of Directors Briefs

- *NPRR973*: Adds definitions for "generator step-up" and "main power transformer" to the Nodal Protocols and clarifies their uses.
- *NPRR983*: Deletes remaining gray-boxed language associated with *NPRR257* (Monitoring Programs and Changes to Posting Requirements of Documents Considered CEII).
- *NPRR990*: Deletes the remaining gray-box for *NPRR889* (RTF-1 Replace Non-Modeled Generator with Settlement Only Generator) and relocates the defined term "combined cycle train" from "Resource" to "Resource Attribute."
- *NPRR992*: Ensures that the day-ahead liability estimate correctly includes ERCOT contingency reserve service (ECRS) charges and payments, as intended by *NPRR863* (Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve).
- *NPRR993*: Clarifies gray-boxed language after the concurrent approval of *NPRR902* (ERCOT Critical Energy Infrastructure Information) and *NPRR928* (Cybersecurity Incident Notification).
- *NPRR996*: Aligns the protocols' hub bus names with the substation names within the ERCOT model.
- *NPRR1000*: Removes the term "dynamically scheduled resource" from the protocols.
- *NPRR1002*: Establishes ESR "single model" registration and charging restrictions during emergency conditions.
- *NPRR1003*: Replaces all remaining references to the RARF with more general language in anticipation of the form's elimination.
- *NPRR1004*: Creates a new process for determining the CRR auctions and DAM clearing load-distribution factors by using load forecasting models and existing validation/error correction to determine daily load-distribution factors.
- *NPRR1015*: Clarifies the market system's submission and reporting changes necessary to complete *NPRR863*, implement changes to responsive reserve service and add ERCOT contingency reserve service.
- *NPRR1016*: Clarifies various important reliability requirements for DGRs seeking qualification to provide ancillary service(s) and/or participate in security-constrained economic dispatch.
- *NPRR1020*: Allows ESRs with integrated loads that cannot be metered as designed to use internal sensors in calculating the loads.
- *NPRR1030*: Changes the CRR auction revenue distribution allocation methodology from a peak 15-minute settlement interval to a load-ratio share based on adjusted metered load totals for each month. Also makes parallel changes for the CRR balancing account and certain block load transfers for consistency and implementation's ease.
- *NOGRR195*: Addresses the Texas Reliability Entity's audit recommendations for ERCOT and modifies generator voltage control tolerance bands.
- *NOGRR196*: Clarifies language used by NPRR973-proposed defined terms "generation step-up" and "main power transformer."
- *NOGRR200*: Deletes all remaining gray-boxed language associated with *NOGRR025* (Monitoring Programs for QSEs, TSPs and ERCOT).
- *NOGRR208*: Aligns the NOG with the Nodal Protocols as modified by NPRR1002. An alignment NOGRR for energy emergency alert will be filed following NPRR1002's approval to align with the protocols.
- *NOGRR209*: Replaces all remaining references to the RARF with more general language to align with NPRR1003.
- *NOGRR212*: Aligns the guide with NPRR1016's revisions and clarifies DGRs' various reliability requirements.
- *OBDRR018*: Aligns the procedure for identifying resource nodes with NPRR1003's changes by replacing all remaining references to the RARF with more general language.
- *OBDRR019*: Aligns the requirements for aggregate load resource participation in the ERCOT markets with NPRR1003's changes by replacing all remaining references to the RARF and updates the process's change control process with similar OBDs.
- *PGRR074*: Clarifies language used by NPRR973-proposed defined terms "generation step-up" and "main power

ERCOT News

ERCOT Board of Directors Briefs

transformer."

- *PGRR076*: Changes the generation resource interconnection or change request process to specify that the proposed commercial operations date in the initial application must be 15 months or greater than the date of the application; redefines the security screening study output; creates separate reports for the full interconnection study; coordinates reactive study; and clarifies when the dynamic data model should be submitted to meet the quarterly stability assessment prerequisite deadline.
- *PGRR078*: Specifies that data related to the regional transmission plan and special planning studies considered protected information may be posted to the market information system's (MIS) certified area for transmission service providers. The change also includes updated resource asset registration form generator data postings to the MIS.
- *PGRR079*: Aligns the guide with NPRR1003's changes by replacing all remaining references to the RARF.
- *PGRR080*: Aligns the Planning Guide with NERC Reliability Standard TPL-007-4 (Transmission System Planned Performance for Geomagnetic Disturbance Events) by identifying responsibilities for performing studies needed to complete benchmark and supplemental geomagnetic disturbance vulnerability assessments.
- *RRGRR022*: Clarifies language used by NPRR973-proposed defined terms "generation step-up" and "main power transformer."
- *RRGRR024*: Aligns the glossary with NPRR1003's changes by replacing all remaining references to the RARF.
- *RRGRR026*: Adds a new data point to support implementation of an interim solution representing DGRs and distribution ESRs in the ERCOT network operations model.
- *SCR810*: Adds logic to ERCOT's EMS by removing the flag that indicates to the operator that a unit representing a DC tie does not count toward the 2% criterion for activating transmission constraints.
- *VCMRR207*: Removes from the manual and its appendix language regarding the validation rules imposed on ERCOT's external telemetry and used in the resource-limit calculator. This maintains consistency between the manual and the protocols by aligning ESR-related provisions with *NPRR986* (BESTF-2 Energy Storage Resource Energy Offer Curves, Pricing, Dispatch, and Mitigation) and its provision that ESRs do not have start-up or minimum-energy costs and sets their mitigated offer cap at the systemwide cap.
- *VCMRR029*: Aligns the manual with NPRR1003's changes by replacing all remaining references to the RARF. ■

— Tom Kleckner

ISO-NE News

Maine Court Rejects Referendum on Tx Project

Continued from page 1

"The ruling by the Maine Supreme Court is a victory for Maine and our future, both environmentally and economically. The Clean Energy Corridor makes Maine a leader in the efforts to address the climate crisis, removing millions of metric tons of carbon from our air," project officials tweeted. "We now look forward to completing the permitting process and getting to work to deliver the benefits of this project to all Mainers."

Opponents of the project vowed to continue their fight, however. Former state Sen. Tom Saviello, who leads a group opposed to the corridor, told the *Bangor Daily News* the opponents could seek legislation blocking the project or launch another referendum drive. "We're not giving up," he said. "This is just the beginning."

The $1 billion NECEC project would span 145 miles, with capacity to carry 1,200 MW of Canadian hydropower from the Maine-Québec border to Lewiston, Maine, where it will connect to the New England Control Area. The HVDC project includes upgrading 50 miles of existing AC transmission, a new converter station, a new substation and other upgrades.

NECEC says Massachusetts electric customers will pay for the entire project. The state entered negotiations with NECEC in 2018 after the New Hampshire Site Evaluation Committee rejected the competing Northern Pass project. (See Massachusetts Bids Adieu to Northern Pass.)

Referendum

The referendum would have asked voters to direct the PUC to issue an amended order finding that NECEC is not in the public interest.

NextEra Energy Resources, which owns fossil fuel generators in Maine and Massachusetts and the Seabrook nuclear plant in New Hampshire, intervened in support of the referendum, along with several voters and a generator-funded group called Mainers for Local Power.

Supporters argued that the substance of the referendum was consistent with the state constitution "because the legislature merely delegated legislative power to the commission, and the legislature remains free to interpose itself in proceedings where the commission has acted," the court said in summarizing their position.

A rendering of what the poles will look like along CMP's 145-mile transmission line | *Central Maine Power*

The court disagreed, saying legislative activity does not involve matters to which the legislature has delegated decision-making power.

"Directing an agency to reach findings diametrically opposite to those it reached based on extensive adjudicatory hearings and a voluminous evidentiary record, affirmed on appeal, is not 'mak[ing] and establish[ing]' a law," the court ruled.

"Separate from its role in legislating through rulemaking to regulate public utilities, the commission functions in an executive capacity as an administrative agency, including by holding a public hearing — sometimes, as in the proceeding at issue here, a hearing substantial both in duration and in the volume of information submitted to and considered by the commission — and rendering a decision in a particular case when a utility has applied for a certificate of public convenience and necessity," the court said. "The commission's adjudicatory decisions therefore are subject to judicial — not legislative — review."

The court said any motions for reconsideration of its ruling must be filed within five days after the order is published because ballots for the November 2020 election must be printed starting at the end of August.

Big Spenders

The battle over the referendum has generated millions in spending in the small state.

Clean Energy Matters, a political committee funded by CMP and Hydro-Québec, has reportedly spent at least $16.7 million to oppose the referendum. Calpine and Vistra Energy, which own natural gas generators in Maine, planned to spend $6 million supporting the initiative through Mainers for Local Power, Maine Public Radio *reported* last month.

The project also has split environmental groups in the region. The Conservation Law Foundation has been supportive, saying it will deliver low-carbon power to New England and allow retirement of fossil fuel plants. The Natural Resources Council of Maine opposes the line, saying it will have a negligible impact on carbon emissions while damaging the state's woodlands.

About two-thirds of the line would be built along CMP's existing rights of way, with the remainder routed through commercial timberland.

The 53 miles of new ROW will result in a 150-foot width clearing with an additional 150 feet undeveloped, NECEC says.

The routes where the HVDC line will be co-located with existing CMP transmission lines are 300 to 500 feet wide, with 150 feet or more cleared for existing lines. NECEC said it will clear an additional 75 feet for the new line in those locations.

CMP hopes to begin construction in 2020 and have the project in service by 2022. The Maine Department of Environmental Protection *issued* CMP a permit in May for construction of the project, which still needs approval from the U.S. Army Corps of Engineers and a presidential permit to cross the Canadian border.

Avangrid shares closed at $50.02/share Thursday, up 38 cents (0.77%). ■

ISO-NE News

NEPOOL Markets Committee Briefs: Aug. 11-13, 2020

The New England Power Pool's Markets Committee held a three-day meeting last week, with much of the time devoted to revising parameters and inputs for Forward Capacity Auction 16 (capacity commitment period 2025/26). Here are some of the highlights.

ISO-NE Seeks to Sunset Forward Reserve Market

ISO-NE is seeking to sunset the Forward Reserve Market (FRM) to avoid conflicts with its proposed Energy Security Improvements (ESI) initiative.

The FRM awards obligations for 10-minute non-spinning reserves and 30-minute operating reserves.

ISO-NE's Jonathan Lowell told the committee that transmission investments and market changes, including the anticipated implementation of ESI, have or will relieve many locational constraints and reward resource flexibility. Because of those changes, and prior recommendations by the External Market Monitor, the RTO is proposing sunsetting the FRM on June 1, 2025, assuming FERC approves related ESI components.

Lowell said FRM and ESI cannot "peacefully coexist" because both procure 10- and 30-minute reserves and that FRM's weaknesses cannot be corrected through incremental fixes. FRM does not use a two-settlement market design, relies on administratively calculated penalties and requires real-time energy offers above cost, resulting in an inefficient co-optimized real-time dispatch, the RTO says.

FRM was created as a supplemental payment to peakers. Although ESI has a different primary purpose — creating incentives to ensure energy security in real time — the two constructs would both award commitments prior to real time.

The RTO would align the FRM sunset with the net cost of new entry updates for FCA 16, contingent on FERC's acceptance of 10- and 30-minute day-ahead reserves in either the RTO or NEPOOL version of the ESI proposal. (See *ISO-NE Sending 2 Energy Security Plans to FERC*.)

To receive a FERC order by March 1, 2021, ahead of the retirement bid delist window, the RTO plans to make the sunset filing contemporaneously with Forward Capacity Market parameters by the end of the year. CONE and other assumptions used in FCA 16 depend on estimates of ancillary revenues from sources such as FRM.

Lowell said the RTO is not concerned about removing incentives for new peakers to supplement increasing amounts of intermittent resources because the region has ample generation and fast-start capacity. Market changes over the last 10 years have added rewards for resource flexibility: fast-start pricing, energy market offer flexibility, Pay-for-Performance, sub-hourly settlements and the existing real-time replacement reserve, he said.

The RTO will present proposed Tariff changes to the committee Sept. 8-10, with an MC vote planned for October and a Participants Committee vote in November.

Wholesale Market Consequences of Gross Load Reconstitution Proposal

Bruce Anderson of the New England Power Generators Association (NEPGA) *asked* the RTO to make a market rule change to avoid suppressing capacity market prices as a result of its proposed gross load forecast reconstitution methodology.

The NEPOOL Reliability Committee on July 21 *supported* Tariff changes to reduce the quantity by which it reconstitutes the long-term peak load forecast. Instead of including all energy efficiency resource megawatts on the system, it would be limited to those that have cleared an FCA. The intent is to produce gross load forecasts that reflect the amount of EE that will clear in that FCA and avoid counting EE resources with capacity supply obligations (CSOs) as both supply and demand.

The change approved by the RC would set the quantity of load reconstitution based on a trend line reflecting historical measures of EE CSOs compared to the level of installed EE.

Anderson said limiting reconstitution to the trend line based on the forecast could result in EE megawatts clearing in the FCA exceeding the level of forecast EE megawatts reconstituted for that auction.

"If that were to occur, the FCA will understate demand and artificially suppress clearing prices," NEPGA said in a presentation. "In addition, a lack of a companion market rule change will leave open the possibility of 'double counting' EE megawatts, i.e., to count those megawatts as both supply (though the

ISO-NE News

NEPOOL Markets Committee Briefs: Aug. 11-13, 2020

acquisition of a CSO) and demand (by failing to reconstitute for that quantity)."

Anderson gave an example in which the trend line found 2,000 MW of EE will clear in the FCA, but the market clears 2,500 MW.

"The additional 500 MW of EE CSO cleared beyond the reconstitution would have the same effect as understating the capacity requirement by 500 MW and artificially suppress the FCA clearing price. The market would also double count the 500 MW," he said.

Anderson suggested the region adopt one of two options:

- Do not qualify EE as capacity supply above the level of EE reflected in the reconstituted peak load forecast; or
- add a constraint in the FCA clearing process to prevent EE megawatts from clearing beyond the level of EE reflected in the peak load forecast.

NEPGA asked that the RTO agree to change Market Rule 1 before the September PC vote on the Tariff changes. It asked that the market rule changes be effective for the first implementation of the Tariff change in FCA 16.

Dynamic Delist Bid Threshold

ISO-NE's Matt Brewster *briefed* stakeholders on a proposed revision to the methodology the RTO uses to recalculate the dynamic delist bid threshold (DDBT) for FCA 16. The threshold was last updated for FCA 13.

The DDBT sets the price range above which static delist bids are subject to pre-submittal and cost reviews.

Suppliers controlling enough capacity to benefit from market power whose bids exceed the threshold may have those bids reduced by the Internal Market Monitor.

Brewster said the RTO attempts to identify delist bids that may represent market power without unnecessarily interfering in competitive price formation.

ISO-NE's proposed recalibration method would estimate the competitive clearing price for the next FCA using public data: the last FCA's cleared supply and clearing price and forecasted demand changes (net installed capacity requirement (ICR), net CONE) for the next FCA.

Brewster said the recalibration estimate showed an average 25% error for FCA 9 through 15 compared with a 39% error with the current "manual" estimation.

He said the proposal's use of current and forward-looking market information should improve accuracy and allow it to "catch up" with unforeseen market changes by the next period. It also will be aided by the recent transition to demand curves based on the marginal reliability impact (MRI) of capacity, he said.

The committee also heard from Vice President of Market Monitoring Jeff McDonald, who said he sees the function of the DDBT as avoiding mitigation for resources whose bids are too low to create market power concerns. "Constructing the DDBT to achieve this goal requires a method that can reasonably be expected to produce a threshold price that is below the auction clearing price," he said in a *memo* to the committee.

McDonald said expanding the function of the DDBT to "support" prices or "complement" the Competitive Auctions with Sponsored Policy Resources (CASPR) could interfere with competitive price formation. "I am not in favor of expanding the function of the DDBT specifically to (i) serve a price support purpose or (ii) increase the amount of capacity that may opt into the Supplemental Auction. Artificial price supports (whether explicit or by way of allowing uncompetitive bidding) introduce inefficiencies, resulting in excess capacity and cost."

Parameters for FCA 16

ISO-NE's Deborah Cooke gave a *presentation* on the recalculation of gross CONE, net CONE and offer review trigger prices (ORTPs) for FCA 16 with a focus on the proposed "level of excess" adjustment for energy and ancillary service (E&AS) revenue calculations.

Cooke addressed a stakeholder suggestion that net CONE estimates should reflect the region's current capacity surplus rather than using the assumption that the system is "at criterion" — with supply and demand perfectly balanced to achieve the region's one-day-in-10-years loss-of-load expectation (LOLE).

ISO-NE estimates its excess capacity for FCA 16 is 791 MW, based on an expected net ICR of 33,165 MW and CSOs from FCA 14 of 33,956 MW. (See *ISO-NE Capacity Prices Hit Record Low*.)

Cooke said the RTO opposed an approach that used the same gross CONE value but calculated the E&AS offsets reflecting the system at surplus.

ISO-NE opposes the change because increased capacity tends to reduce expected E&AS revenues, which would increase the net CONE estimate above the RTO's proposed value, Cooke said. She said this would induce new competitive entry, even when the system already has more capacity necessary to meet its LOLE standard.

Brett Kruse of Calpine questioned the RTO's example, saying he was unaware of any generation developer that would rely solely on ISO-NE price estimates.

"I don't think any developer of any stature would pretend that we're at equilibrium as they're figuring out whether their projects go forward," he said. "I think the ISO's price point is only one aspect of that, if that. That's why I think the whole philosophy that you're building the example on is inaccurate."

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

Robert Stoddard, who *made the case* for assuming a surplus on behalf of NEPGA at the MC's July meeting, said Cooke's conclusion depends on the slope of the E&AS price curve being steeper than the slope of the MRI.

"My guess is you could construct a different set of examples by using a steeper MRI value and find that this problem does not occur," he said. He elaborated on his point in a *presentation* later in the meeting.

Kruse said after the meeting that generators are hurt by the RTO's use of inconsistent planning parameters. "One of my concerns is not just the 'at criterion' argument here but the fact that they use different metrics; they factor in the oversupply as well as the upcoming state-mandated [resources] when setting the DDBT threshold. … We lose on both sides of the equation."

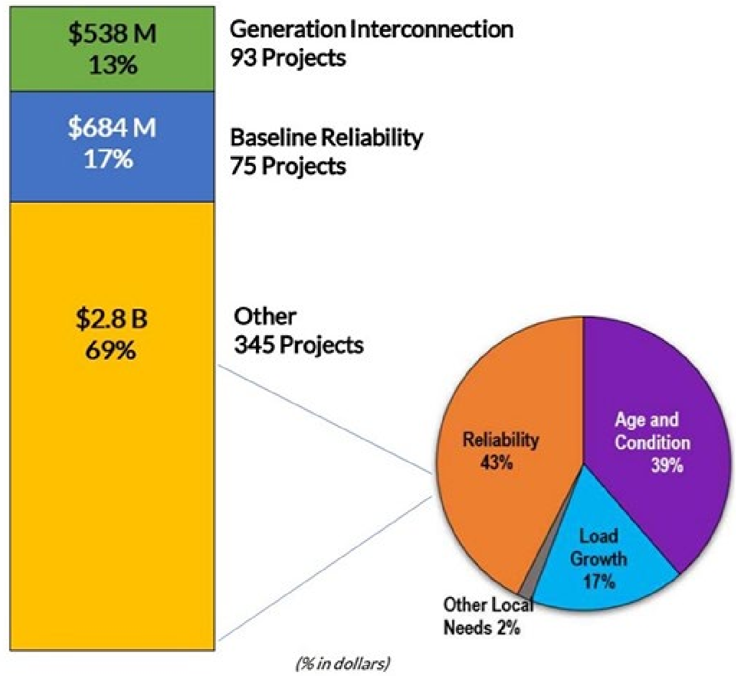
Votes by the MC on the DDBT threshold and updated FCM parameters are expected in October with the PC voting in November. ■

— Rich Heidorn Jr.

MISO News

MISO Processing Heftiest Interconnection Queue Ever

By Amanda Durish Cook



Draft breakdown of MTEP 20's 513 projects | *MISO*

MISO is juggling several transmission planning activities as it faces a cascade of new gigawatts in its interconnection queue, stakeholders heard during last week's Planning Week.

The RTO announced a record number of new queue entrants in July, with customers submitting 353 applications representing about 52 GW of new generation. Solar generation, with 36 GW, accounts for the majority of the new generation proposals.

MISO said the 2020 queue entrants unseated the previous record of 47 GW, set in 2007, and the 44 GW that applied last year.

The new hopefuls bring the *queue* to 756 projects totaling 113 GW, 64% of which is solar. The grid operator is currently managing 13 queue cycles, with another cycle to open in 2021.

MISO was *expecting* about 25 GW of entrants this year, RTO adviser Joe Reddoch said during the Planning Advisory Committee's teleconference Wednesday.

"More stringent requirements and transmission costs did not deter initial response," he said, referring to stricter proof-of-land-use rules and higher network upgrade costs in recent years.

Reddoch said MISO's use of the 2019 transmission planning *futures* — which executives admitted have become obsolete — likely contributed to the understated estimates. He said internal questions were raised as to whether the futures were too outdated and did not reflect a more aggressive renewable generation buildout.

Multiple Tx Planning Efforts Underway

MISO has several transmission planning initiatives underway against the backdrop of the daunting queue.

The RTO has opened a window for stakeholders to propose new planning studies for its 2021 Transmission Expansion Plan (MTEP 21). MISO's new planning futures for 2021 predict anywhere from 148 to 352 GW of natural gas, solar and wind generation coming online over the next two decades.

"We are asking if you have any requests or input you would like to be considered for any additional studies for the MTEP 21 cycle," MISO Project Manager Sandy Boegeman told stakeholders during a Planning Subcommittee (PSC) meeting. The idea submission window is open through Sept. 17.

At the same time, MISO is finalizing MTEP 20 projects it will recommend to the Board of Directors in October.

The MTEP 20 package now contains 513 new projects worth about $4 billion. Boegeman said the total costs are similar to last year's package. However, she noted that this year's $538 million spend on interconnection projects, or about 13% of MTEP 20's costs, is about double that of MTEP 19's.

MISO has also concluded that it should undertake long-range transmission planning studies separate from the annual MTEP study cycle. (See *MISO Foresees Massive Shift to Renewables by 2040*.)

Vice President of System Planning Jennifer Curran said MISO member plans portend a slew of new renewables and retirements of older, conventional resources. She told the PAC that now is the time for a new long-range transmission plan to keep the grid reliable and efficient as the resource portfolio shifts.

"MISO must focus now on solutions that anticipate and adapt to those rapid changes," she said. She said that the long-term transmission studies will focus on renewable integration and transmission constraints, such as the import restrictions in Lower Michigan and the Midwest-South sub-regional limit.

The RTO's last long-range transmission plan culminated in 2011's Multi-Value Project (MVP) portfolio. Curran said this planning iteration won't resemble that of a decade ago.

"I don't think all these projects are going to come at once like the MVPs," she said. "I think we could have multiple groups of projects approved periodically."

Curran said the first projects would likely emerge next year in MTEP 21. She acknowledged that MISO has yet to work through a cost-allocation plan for the long-term projects, but it may be able to use existing allocation methods, such as the market efficiency project (MEP), for some of the MTEP 21 projects.

"But it's important to focus on what the needs are first before we begin those conversations," Curran said. "We don't see cost allocation as a prerequisite for the work. ... There are pros and cons for every cost allocation, and it's going to be challenging."

MISO News

MISO Processing Heftiest Interconnection Queue Ever

Xcel Energy's Drew Siebenaler thanked MISO on behalf of the 10 Minnesota utilities that produced the CapX2050 transmission study for tackling long-term needs. (See *CapX2050 Prompts MISO Focus on Midwest Tx*.) Multiple state regulators also thanked the grid operator. The Organization of MISO States has been keen on a new long-term transmission plan since early 2019.

"We're already seeing this portfolio shift, and we would argue some policies in the MISO states are going to accelerate this transformation," Clean Grid Alliance's Natalie McIntire said.

The grid operator is still working through a plan to coordinate its MTEP and interconnection-queue planning studies.

MISO proposed last month that generation project upgrades would need a minimum rating of 230 kV and cost at least $5 million to be eligible for evaluation as a possible MEP. (See *MISO Unveils 1st Proposal to Consolidate Tx Planning*.)

The RTO is debating whether it should align the interconnection queue and MTEP timelines and whether it should use more than one annual MTEP cycle to approve a transmission project solving multiple needs, provided the project is identified more than five years ahead of time.

MISO Senior Manager of Expansion Planning Edin Habibovic said it would probably be impossible for MISO to totally combine its interconnection queue studies with its economic and reliability planning studies. "But this doesn't prevent us from looking at issues from a holistic point of view … to find a joint solution," Habibovic told the PSC.

"The intent isn't to merge these different planning studies into a single study," MISO Senior Manager of Economic Planning Neil Shah agreed during the PAC teleconference. He added that the grid operator could investigate the concept of a consolidated planning process in the future.

Shah said MISO is currently focusing on fitting a "coordinated, not consolidated" approach that fits into existing Tariff processes. He said there are too many "moving parts" between economic planning and interconnection planning to completely merge them.

McIntire said it was worth considering a combination of some studies in the future. ■

FERC Accepts Trimmer MISO LMR Capacity Accreditation

By Amanda Durish Cook

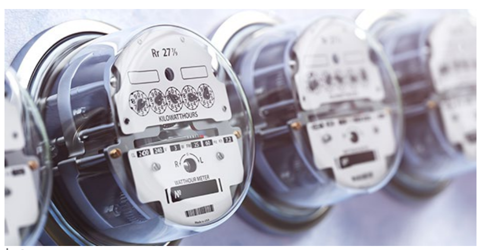
FERC approved new rules Friday likely to reduce load-modifying resources' (LMRs) capacity accreditation in MISO, despite several protests from RTO members.

The commission said accrediting LMRs based on their notification times and the number of calls they respond to is an appropriate means for managing MISO's increase in maximum generation emergencies (*ER20-1846*).

MISO will be able to set an LMR's capacity accreditation at either an average of its actual availability over a three-year period or its tested availability, whichever is less. LMRs that can respond more often and with shorter lead times will receive a larger capacity credit:

- Those that can respond in six hours or less to 10 or more calls per year will receive full capacity credit.
- LMRs ready in six hours or less that can only respond to five to nine calls in a planning year will receive an 80% accreditation.
- LMRs with lead times greater than six hours will be offered a 50% capacity credit for two years if they can respond to at least 10 calls in a year.

The percentage-based accreditation will take effect in the 2022-2023 planning year.



| Shutterstock

Beginning with the 2023-2024 planning year, MISO will stop offering capacity credits for LMRs with six hours or greater lead times or that cannot respond to at least five calls in a planning year. The RTO maintains that LMRs needing more than six hours' notice don't help mitigate emergency conditions.

MISO's proposal is more lenient than an earlier version that would have eliminated slow-response LMRs two years earlier. (See *MISO Delays New LMR Accreditation Launch*.)

FERC said the arrangement was reasonable considering MISO's increased reliance on LMRs to meet its planning reserve margin requirement and the short notice it usually has before entering emergency procedures.

LMRs currently make up nearly 9% of MISO's planning reserve margin requirement. The grid operator refers to the resources as the last line of defense before having to shed load.

The commission also said MISO's two-year notice before disqualifying slow-response LMRs gives those resources enough time to adjust their response capabilities and better assist in emergencies.

"We find that MISO's proposal to reduce the maximum notification time requirement from 12 to six hours reasonably reflects MISO's ability to predict [maximum generation events] and the ability of LMRs to respond in a timely manner," FERC said.

The commission said the new rules do not unfairly single out LMRs over other capacity resources, as some LMR-owning members argued. On the contrary, FERC said, MISO's plan recognizes LMRs' unique traits.

"We find that MISO's proposal is not unduly discriminatory against LMRs as compared to other capacity resources because MISO's proposal addresses the unique operating and reliability characteristics of LMRs, such as advanced notice requirements and that LMR deployments are limited to [maximum generation events] to prevent firm load shedding," FERC wrote.

MISO isn't done proposing new solutions to encourage LMR availability. Earlier this month, MISO staff said they must correct significant gaps between the LMR capability that clears capacity auctions and what actually responds to MISO emergency instructions. The grid operator has said several LMRs are unavailable in MISO's times of need. (See *MISO Investigating LMR Availability Problem*.) ■

MISO News

FERC Greenlights MISO Storage-as-Tx Proposal

Danly Dissents

By Amanda Durish Cook

MISO's much debated first rule set for storage resources functioning as transmission assets passed muster with FERC last week, though Commissioner James Danly opposed the plan (*ER20-588*).

| Enel X

The commission approved the proposal, effective immediately, subject to MISO providing more explanation on storage-as-transmission resources' impact on the interconnection queue, special commercial pricing nodes for the resources and instances when storage wouldn't be used to solve transmission reliability issues.

Danly dissented, saying the plan "impermissibly blur[s] the line between generation and transmission."

The rules limit storage-as-transmission assets to transmission-only functions operated by MISO-defined transmission owners. Such assets will be called storage-as-transmission-only assets (SATOAs) and will be barred from simultaneous participation in the RTO's energy markets, with SATOA owners responsible for the resources' states of charge. SATOAs would be selected using MISO's annual Transmission Expansion Plan (MTEP).

FERC accepted and *suspended* the plan in March, suggesting that some aspects could be unjust and unreasonable. MISO defended the plan in front of FERC in May at a technical conference on the proposal. The grid operator said the plan is intended to be an interim measure while it designs a more comprehensive approach to allow storage resources to simultaneously participate in the energy markets while providing transmission solutions. (See *MISO Plugs SATOA Plan at FERC Conference*.)

The RTO has repeatedly argued that the short-term plan will avoid introducing complexities around cost recovery, particularly related to how non-TOs would be compensated for providing transmission services. The grid operator has promised to hold stakeholder discussions beginning in 2021 on dual-mode participation of storage in both markets and on the transmission system.

Many in the MISO stakeholder community have said the rules would give incumbent TOs an effective monopoly on storage assets functioning as transmission, harming competition. (See *MISO SATOA Proposal Faces Opposition*.) DTE Energy has been especially outspoken against the plan, maintaining it will create unduly discriminatory preference for TOs over generation owners with comparable projects.

FERC was not swayed by those claims.

"We are not persuaded by protesters' arguments that MISO's proposal is unduly discriminatory toward non-transmission owners seeking to develop storage for transmission uses. As protesters assert, a SATOA is most likely to qualify as a baseline reliability project or other project, and Order No. 1000 allows transmission owners to maintain a right of first refusal for such categories of transmission projects," the commission said.

FERC said that because SATOA would be bound to the same requirements as other transmission projects, the protesters' concerns seemed to be about the RTO's existing Tariff rules, which were not under scrutiny.

The commission also determined that MISO's rules for SATOA evaluation under the annual MTEP process and its proposal to develop unique operating guides for each asset were fair.

"MISO's proposed evaluation criteria will result in MISO choosing SATOAs that are properly characterized as transmission assets eligible for cost recovery in transmission rates," FERC said. "The proposal ensures that SATOAs will be subject to adequate scrutiny in order to ensure that the SATOA is the preferred solution to an identified transmission need."

Some protesters argued that MISO should treat SATOAs the same as non-transmission alternatives (NTAs), which must first clear the RTO's approximately three-year generation interconnection queue before being placed in operation. SATOAs, meanwhile, would only have to clear the RTO's annual MTEP studies. But the commission noted that the RTO is only required to consider proposed NTAs as alternatives to transmission solutions, while SATOAs will be considered as transmission solutions themselves. "MISO's SATOA proposal does not change MISO's existing process to consider transmission and NTAs on a comparable basis," it said.

Some Revisions Needed

FERC said MISO's plan sets reasonable limitations on SATOAs' activity; however, it ordered the RTO to further detail the special commercial pricing nodes it will create for energy injection or withdrawals. The RTO needs to make plain that no other energy trading activities will be allowed at the new nodes, FERC said.

The commission also said MISO, for the most part, built in adequate protections so that SATOAs don't affect generators seeking to interconnect. But it said the plan lacked detail on how the RTO will evaluate the impact of a SATOA on the interconnection queue and ordered the RTO to document the process in a new filing.

Finally, FERC directed MISO to clarify that it

MISO News

FERC Greenlights MISO Storage-as-Tx Proposal

doesn't intend to use SATOAs to correct routine reliability transmission issues that could instead be solved by a market solution.

Danly: Discrimination Claims Inevitable

Commissioner Danly said MISO's proposal improperly conflated generation and transmission.

"No matter how our order characterizes the function of energy storage facilities, the service contemplated by [MISO's] filing is accomplished through the discharge of energy from storage units into the MISO transmission system. That, in my view, is a generation function, not a transmission function," he wrote in dissent.

Danly said the order flies in the face of FERC's precedent of unbundling transmission services provided by generation facilities from transmission rates. He said it's only natural that "similarly situated," non-transmission-owning parties want a better explanation as to why they can't own SATOAs.

"I am concerned that, once the door is opened, it can swing in only one direction, and we soon will be faced with proposals seeking to widen the opening ever further," he said. "The further we expand the definition of transmission by including facilities that inject energy into the system, the more difficult it will be to prevent yet further expansion. And the commission will find it challenging to justify its actions in the face of the discrimination claims that inevitably will be raised by generators seeking the same full cost-of-service treatment afforded to transmission assets."

Danly said generation assets, like storage, should be limited to providing ancillary services to preserve the bright line between transmission and generation. He said FERC should reverse its 2010 decision that allowed storage developer Western Grid to classify its resources as transmission for cost-based recovery in CAISO. ■

MISO Pledges More Cost Allocation Work After Overhaul

By Amanda Durish Cook

| *Cleco*

MISO is not giving itself time to celebrate after FERC recently accepted its transmission cost allocation plan, promising more such work on long-term and interregional projects.

"We made it. We got across the finish line. After about three years of stakeholder discussion and a year and a half of FERC rejections, we did it," MISO Senior Manager of System Planning Jarred Miland joked during the Regional Expansion Criteria and Benefits Working Group's (RECBWG) teleconference Thursday.

MISO's plan lowered the voltage threshold for market efficiency projects (MEPs) from 345 kV to 230 kV and eliminated the 20% postage-stamp allocation in favor of allocating full costs to benefiting transmission pricing zones. It also added two new benefit metrics based on whether a project can reduce dependency on the RTO's transmission contract path with SPP or eliminate needs for other reliability projects. FERC approved the plan in late July. (See *MISO Cost Allocation Plan Wins OK on 3rd Round*.)

But the RECBWG's work on transmission project cost allocation is far from over.

"I feel like it was time to take a nap, but then [Vice President of System Planning Jennifer Curran] kicked off expanded long-range transmission planning yesterday," Miland said, referring to Curran's announcement Wednesday to the Planning Advisory Committee that MISO will explore long-range transmission solutions — and may have some project recommendations as soon as next year.

The working group will likely forge new cost-allocation methodologies for any long-range transmission projects that may result. Several stakeholders asked when and how the group would approach the effort.

"We have to figure out what we're talking about first," Miland said in asking for patience. Long-range transmission discussions are continuing in MISO's planning committees, and Miland said the RECBWG must wait to see what projects develop before it devises cost-sharing methods.

"It's not baked yet; it's not ready for primetime," he said.

Miland also said the grid operator is now considering another filing to lower the voltage threshold on interregional MEPs with PJM from 345 kV to 230 kV.

That seemed to confuse stakeholders, who said the interregional project allocation voltage threshold was already *lowered* to 100 kV after a 2013 complaint at FERC by Northern Indiana Public Service Co. against the MISO-PJM interregional planning process.

Miland clarified that currently, the RTOs' interregional economic projects between 100 and 345 kV are allocated to benefiting transmission zones based entirely on the original adjusted production cost metric. MISO is proposing to additionally use the two new benefits metrics to evaluate 230-kV+ MISO-PJM interregional projects.

"I think it would be a pretty simple filing to do," Miland said. MISO's rationale is that it would align both the RTO's regional and interregional project evaluations, he said.

But Clean Grid Alliance's Natalie McIntire argued that because FERC ordered a 100-kV threshold on MISO-PJM interregional projects, the RTO should also apply that to any benefit metrics.

Some stakeholders asked if MISO would also consider a filing applying the two new benefit metrics to economic projects with SPP.

"Frankly, we have not had any conversations around that," Miland said. ■

NYISO News

NY PSC Gets Update on Tx Planning, Investment Efforts

Utility Proposals on Meeting CLCPA Goals due in Oct.

By Michael Kuser

The New York Public Service Commission heard a progress report Thursday on a grid study underway to identify distribution upgrades, local transmission upgrades and bulk transmission investments needed to meet the state's clean energy goals, as well as brief outlines of three separate petitions on large-scale public policy transmission needs (Case No. *20-E-0197*).

"We need more; we need smarter; we need faster transmission," PSC Chair John B. Rhodes said. "Recognizing this, there is necessarily a lot going on."

Tammy Mitchell, chief of bulk electric systems for the state's Department of Public Service (DPS), said the study results — due Nov. 1 — will inform two separate investment plans to be established by the PSC, one related to distribution and local transmission investments or upgrades, and another plan for bulk system transmission investments.

The commission in May *authorized* the study as directed the previous month by the Accelerated Renewable Energy Growth and Community Benefit Act (*A09508*), which set up the Office of Renewable Energy Siting and required investment plans to meet the renewable energy targets of last year's Climate Leadership and Community Protection Act (*CLCPA*). (See *NYPSC Launches Grid Study, Extends Solar Funding*.)

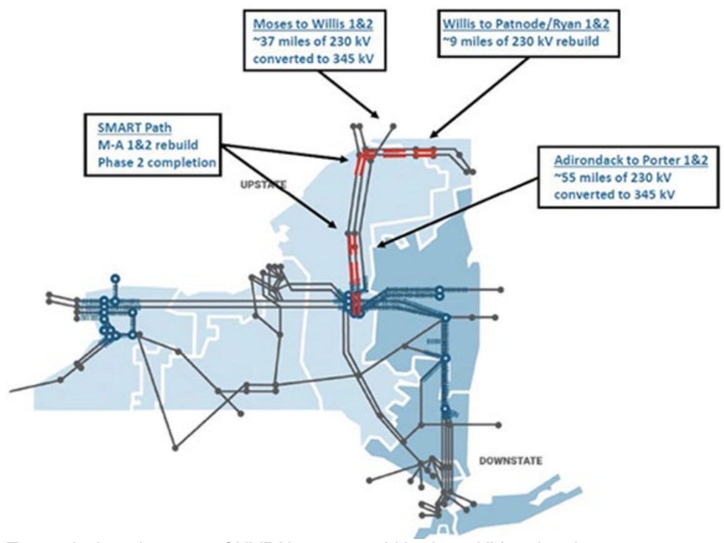
The CLCPA mandates that 70% of the state's electricity come from renewable resources by 2030 and that electricity generation be 100% carbon-free by 2040. Its clean energy targets include doubling distributed solar generation to 6 GW by 2025, deploying 3 GW of energy storage by 2030 and raising energy efficiency savings to 185 trillion BTU by 2025.

The PSC in May also directed utilities to file proposals to incorporate the statutorily mandated environmental benefits in utility planning and investment criteria, and proposals to prioritize such projects in their capital spending and apply benefit/cost analysis for potential investments. It also directed them to file cost-containment, cost-recovery and cost-allocation methods. All proposals are due no later than Oct. 5.

The commission will seek public comments on the grid study results and utility proposals and expects to be able to move ahead with distribution and local transmission upgrades early in 2021, Mitchell said.

3 Projects Now Being Sited

New York currently has three 345-kV transmission projects underway that were selected through the NYISO Public Policy Transmission Planning process and are in the Article VII — or full review — siting process, Mitchell said.



Transmission elements of NYPA's proposed Northern NY project | *NYISO*

NYISO selected NextEra Energy's Empire State Line proposal in October 2017 to obtain full output of the New York Power Authority's (NYPA) Niagara hydro facility, maximize Ontario inflows and maximize exports of renewable resources out of western New York to the rest of the state. The line is expected to be in service in the first half of 2022.

The other two projects underway were selected by NYISO last year as part of the broader AC Public Policy Transmission Project. One being built by LS Power and NYPA will increase transmission capacity by approximately 800 MW at the Central East (Segment A) electrical interface, well above the commission's minimum of 350 MW, she said. (See *NYISO Board Selects 2 AC Public Policy Tx Projects*.)

Another by New York Transco for the Upstate New York/Southeast New York (Segment B) interface will run from the Albany region to the Hudson Valley region, increasing transfer capability by about 2,000 MW, well above the commission's minimum of 900 MW.

Both of the latter projects are expected to be in service by December 2023, Mitchell said.

Fast-track Proposals from NYPA, DPS, LIPA

On July 2, NYPA and the DPS submitted a two-part *petition* to the PSC that included DPS staff's proposed criteria for determining priority projects and a NYPA proposal that the commission designate its "Northern NY Project" as a priority project to be developed under the new siting law.

The DPS criteria included an investment's potential for unbottling existing renewable generation, avoiding future congestion and increasing the deliverability of existing and anticipated baseload renewable or low-carbon generation. It also factored in whether an early in-service date would increase the likelihood of meeting CLCPA targets and considered the transmission investment's eligibility for expedited review under Article VII and its implementing regulations.

The redacted public version of the petition does not include cost estimates, but in it, NYPA estimates the project will result in approximately 7.5 TWh of avoided renewable curtailments annually, starting in 2025, and result in production cost savings of approximately $99 million per year, for a net present value of approximately $1 billion over a 20-year period.

The Northern NY Project "will establish a continuous 345-kV path that greatly expands the deliverability of renewable generation from northern and western New York to load centers," while compounding the benefits from the Segments A and B projects already underway, NYPA said.

On July 13, NYPA filed another *petition* asking

NYISO News

NY PSC Gets Update on Tx Planning, Investment Efforts

the PSC to designate its Western New York Energy Link Project (WNYEL) to also be a priority for the state.

NYPA said the project will upgrade assets owned by National Grid, New York State Electric and Gas and NYPA to reduce or eliminate existing curtailment of renewable and carbon emission-free generation, facilitate the siting of new renewable generation in the area and increase transfer capability from the region to load centers by approximately 600 MW.

The WNYEL project includes reconductoring two 42-mile Packard-Huntley-Gardenville 230 kV circuits; a tower separating 230 kV lines; converting the existing double-circuit common tower structures to single-circuit single tower structures; and installing a new phase angle regulator at the South Ripley substation to control the flow from PJM to the New York Control Area.

NYPA said NYISO's 2019 Congestion Assessment Resource Integration Study, issued in June 2020, supports the need for additional transfer capability near the Niagara Power Project, citing the study's identified renewable generation pockets. (See *Bulk Tx, 115-kV Upgrades Needed for NY 70×30 Goal*.)

NYPA asked that if the PSC does not designate WNYEL as a priority project, the commission instead direct National Grid and NYSEG to undertake the necessary improvements to develop the project in coordination with NYPA.

Collectively, NYISO projected that Zone A will be the site of more wind and solar generation than any other zone except for Zone J (New York City), and found three potential areas of transmission bottlenecks, identified as pockets W1, W2 and W3. NYISO projected curtailments of 20 to 30% for solar generation between and 5 to 8% for land-based wind resources.

The Long Island Power Authority (LIPA) on July 30 submitted to the PSC a FERC Order 1000 referral, as allowed under the NYISO Tariff, seeking the commission's determination that the 2018 Offshore Wind Standard is a public policy driving the need for transmission. LIPA also asked the PSC to find a need for additional export capability on the Consolidated Edison interface, as well as for upgrades to the local transmission system on Long Island to support the 2018 OSW procurement target of 2,400 MW (*18-E-0623*).

Two years ago, NYISO solicited proposals for transmission needs driven by public policy requirements and, in October 2018, submitted to LIPA seven of the 15 proposed needs it received from stakeholders, including one from PSEG Long Island that summarized the OSW procurements as giving "rise to the need to optimize transmission development and to create a 'transmission backbone' structure in order to meet the state's ambitious goal of 2,400 MW of resources by 2030."

"The transmission system was originally built to serve native load of monopoly utilities, and ratemaking at both the state and federal level was based on that," Commissioner John B. Howard said. "This new paradigm is as dramatically different from that as can be imagined, since the primary focus of our bulk transmission system will now be to enhance and provide environmental benefits through zero-emissions generation across the state." ■

NYISO Moves Forward on EAS Projects

BIC Recommends SENY Reserve Enhancements to MC

By Michael Kuser

NYISO continues to advance its Grid in Transition agenda, moving ahead with some energy and ancillary services (EAS) projects while suspending or combining others.

The Business Issues Committee on Wednesday recommended the Management Committee approve the ISO's Reserves for Resource Flexibility *project* to increase the portion of the total statewide reserve requirement for Southeast New York (SENY, zones G-K) from 1,300 MW to 1,550 or 1,800 MW depending on the hour. Stakeholders in July had delayed a vote on the proposal pending additional cost analysis. (See *NYISO BIC Balks on Increased Reserves*.)

If the MC approves the proposal on Aug. 26, the ISO will seek to implement it in 2021.

Preparing for Uncertainty

Michael DeSocio, director of market design, *updated* stakeholders on NYISO's coordination of other EAS projects, including ancillary services shortage pricing; constraint-specific transmission shortage pricing; more granular operating reserves; and the reserve enhancements for constrained areas project.

The ISO will continue to discuss the ancillary services shortage pricing proposal over the coming months, complete the consumer impact analysis in September, target seeking stakeholder approval in October and, if approved, implement it after the Reserves for Resource Flexibility initiative takes effect in 2021, he said.

The proposal is intended to improve real-time energy pricing during tight operating conditions to incent resource performance and improve economic signals for import and export scheduling.

"We're trying to prepare for a world where there's just going to be more uncertainty," DeSocio said. "We'll have more intermittent resources; we will have more resources that we'll need to manage better over the course of a day, like energy storage or DERs; and therefore, we need to make sure the market is sending the pricing signals needed for resources to be available."

There are still times when the shortage pricing could be improved to help ensure resource availability. Without flexible resources to help manage real-time conditions, the ISO may need to rely on uneconomically curtailing exports, purchasing emergency energy from neighboring regions or making out-of-merit commitment of uneconomic internal generators, DeSocio said.

It also can make additional commitments of generation after the day-ahead market through supplemental resource evaluations (SREs). All tools like SREs have impacts that can lead to issues where the market fails to incent the need for flexible resources like storage, he said.

"If we're going to guarantee that any time a committed generator is added to the system, we're going to make it whole to its minimum generation cost, there's not a lot of incentive for it to reduce that min-gen cost because it's not losing anything with the current structure," DeSocio said. "By getting these reliability actions into the market directly, now the market can come up with a better mix and

NYISO Moves Forward on EAS Projects

better pricing outcomes."

Shifting Priorities

NYISO will continue to discuss its "constraint-specific transmission shortage pricing" proposal next year, but based on stakeholder feedback, it wants to shift resources away from the development of this proposal to supporting the development of the distributed energy resource participation model, DeSocio said. If stakeholders approve the transmission shortage pricing proposal by the end of 2021, the ISO will further consider implementation timing during the 2022 project prioritization planning.

In addition, NYISO recommends suspending work on the "more granular operating reserves" project to allow focusing on the "reserve enhancements for constrained areas" project, which will investigate ways to dynamically allocate reserves requirements between regions based on available transmission head room.

This project will evaluate ways to improve the modeling of reserve and transmission constraints to potentially allow reserve requirements to be shifted to lower-cost reserve regions as long as transmission head room exists to deliver the reserves to where needed without compromising reliability.

NYISO says this functionality would greatly improve the existing proposal for procuring reserves in certain New York City load pockets based on the design developed in the more granular operating reserves project.

The ISO recommends next year studying ways to potentially include a dynamic reserve allocation in the existing market software. ■

NYISO Proposes ICAP Demand Curve Reset Values

By Michael Kuser

NYISO last week told stakeholders that it supports most of its consultants' *proposed* parameters and assumptions for the installed capacity (ICAP) demand curves for capability years 2021/22 through 2024/25.

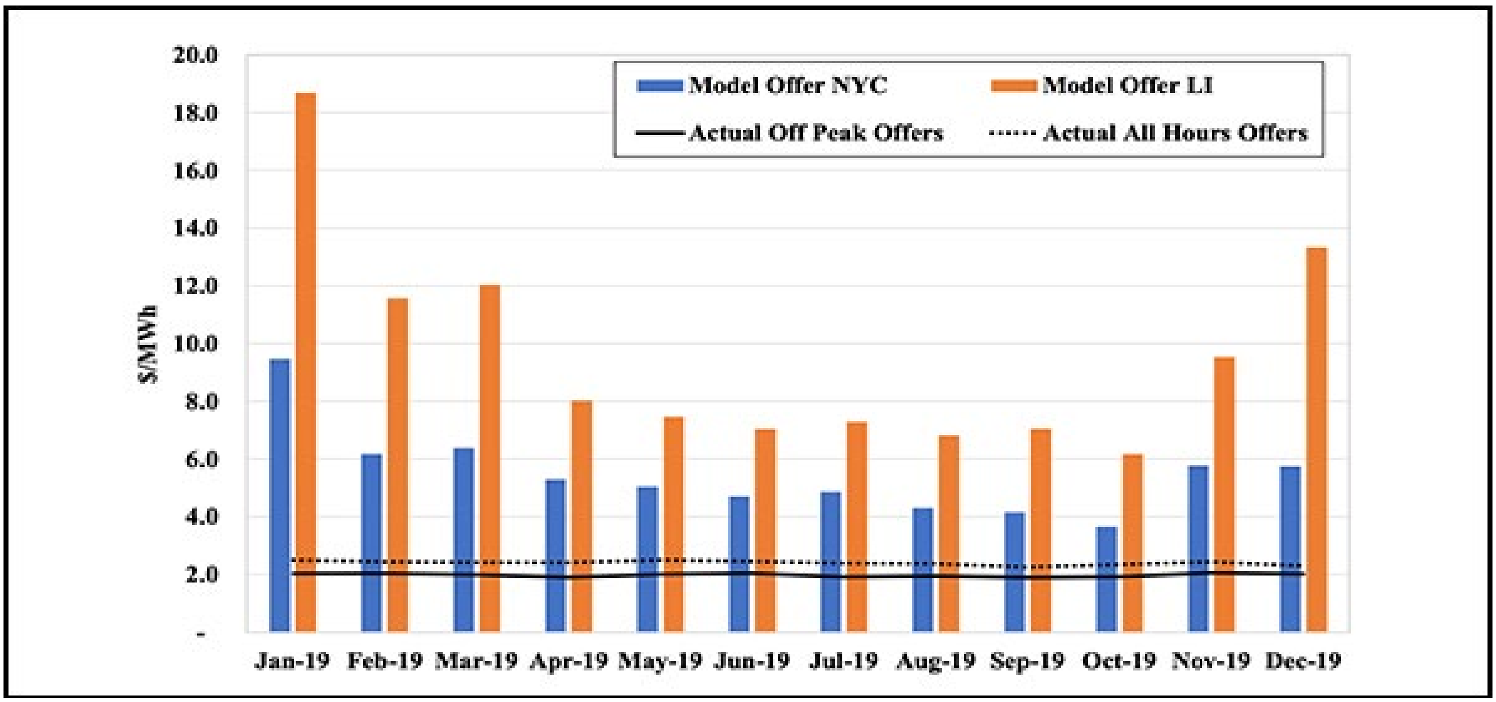
In their quadrennial review for the demand curve reset (DCR), Analysis Group and Burns & McDonnell recommended that General Electric's 7HA.02 turbine be selected as the peaking plant for the ICAP demand curves for all of the state.

The consultants determined preliminary reference points — which equal the clearing price at 100% of the minimum capacity requirement — ranging from $7.74/kW-month for the New York Control Area (without selective catalytic reduction (SCR) emissions controls) to $21.36/kW-month for New York City, with SCR.

Capacity Market Design Manager Zachary Smith, who presented the draft staff *recommendations* to the Installed Capacity/Market Issues Working Group, said ISO staff are continuing to evaluate certain of the consultants' recommendations, including the maximum clearing price, which is set at 1.5 times the estimated monthly value of the cost to develop a new peaking unit.

Both the reference point price and the maximum clearing price calculations require translating annual values into monthly values.

But while the translation of the annual reference value — also known as the net cost of new entry (CONE) — to the monthly refer-



Day-ahead reserve offer data provided by the MMU for dual-fuel units in Zones J and K suggest that previous assumptions may overstate the cost of providing reserves, particularly for dual-fuel units, which can operate on secondary fuel if converted to energy in real time. | *Analysis Group*

NYISO Proposes ICAP Demand Curve Reset Values

ence point value uses a translation factor to account for excess conditions and seasonal differences in capacity availability, the factor is currently not applied when determining the monthly value of gross CONE.

As a result, NYISO said, there is a potential for the different methodologies to produce a reference point price that exceeds the maximum clearing price, with a greater risk of such outcomes in smaller regions. To avoid such an outcome, the ISO is considering whether to applying a translation factor in determining the monthly gross CONE value used to determine maximum clearing prices.

"Obviously, most of the focus in this process has been on the reference point; however, we are required to come up with a maximum price, as well as the zero crossing point [the point at which the value of marginal capacity declines to zero] for each locality and the NYCA," Smith said.

Staff said they preliminarily agreed with the consultants' proposed handling of scaling factors used to adjust the historic prices used for estimating net energy and ancillary services (EAS) revenues to the Tariff-prescribed level of excess conditions assumed for the DCR.

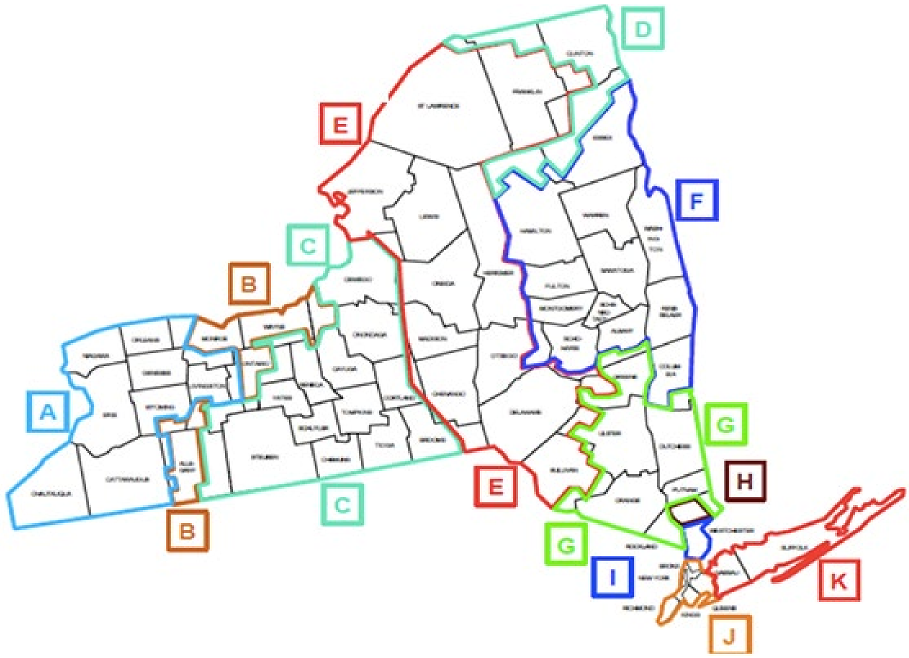
These scaling factors — the level of excess adjustment factors — did not take into account proposed retirements identified in compliance plans for the state Department of Environmental Conservation's "Peaker Rule," new NO_x regulations that go into effect May 1, 2023. (See *NY DEC Kicks off Peaker Emissions Limits Hearings*.)

NYISO said it agreed with excluding the impact of the Peaker Rule because only four months of market prices impacted by the rule's 2023 requirements would be used in the net EAS model. This would occur as part of the annual update for the 2024/25 capability year, for which the historic data period ends Aug. 31, 2023.

The ISO said applying Peaker Rule retirements to all years covered by the DCR "does not fairly reflect the expected system that will be reflected in the historic data periods used for determining net EAS revenue offset estimates for this period."

MMU Review

Potomac Economics, the Market Monitoring Unit for the ISO, said it also supported most of the consultants' methodology and recommendations but called for revising three as-



New York Control Area load zones | *NYISO*

sumptions that "are not supported by market data or reasonable economic considerations," all of which result in inflating net CONE.

"This is particularly harmful at this time given that NYISO is substantially oversupplied, and inefficiently high demand curves will serve to impede efficient retirements and perpetuate the current capacity surpluses," it said. Potomac called for:

- reducing the cost of debt to a range of 6 to 6.5% from the proposed 6.7%. The MMU said the rate should be "based on a broader view of the available data that does not overemphasize the recent COVID-19-related financial market turbulence."
- replace the fuel-procurement cost for the sale of operating reserves with a cost of $2/MWh for dual-fuel units, which it said "would more accurately reflect the fuel reservation costs of reserve providers in New York with oil backup that would not likely incur large gas-procurement costs when selling reserves." Todd Schatzki of Analysis Group said that based on data provided by the MMU, the consultants agree with its recommendation to adjust the day-ahead cost of offering to provide operating reserves for dual-fuel units.
- increase the amortization period to 20 years from 17, which it said was "unreasonably low and ignores publicly available information on how the power system will adapt to the zero-emission provision of the Climate Leadership and Community Protection Act."

Kieran McInerney of Burns & McDonnell, who *presented* portions of the consultants' interim final report, noted that they had seen a wide range of land lease costs in Zone J, used in developing the estimated CONE, but left those costs unchanged as the current assumption is within the observed range.

The consultants previously reviewed market transactions, property tax values and stakeholder feedback, and also considered quoted values obtained through discussions with property owners in the potential acquisition of land.

Stakeholders expressed concerns about modeling values for land lease costs having been adjusted for inflation only.

Timeline

NYISO staff will issue its final DCR report to stakeholders and the Board of Directors on Sept. 9. Stakeholders will have until Oct. 9 to provide written comments to the board, which will hear presentations and debate on Oct. 19. The ISO will file the approved outcomes with FERC by Nov. 30. ■

PJM News

PJM MRC Preview: Aug. 20, 2020

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

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

Consent Agenda (9:05-9:10)

Members will be asked to endorse the following manual changes and Tariff revisions:

B. Manuals 14A, 14B and 14G. Revisions in response to FERC's directives on PJM's second Order 845 compliance filing. (See "Manual 14 Changes," *PJM PC/TEAC Briefs: July 7, 2020*.)

C. Dispatch Interactive Map Application (DIMA). Operating Agreement revisions to grant transmission owners access to the Dispatch Interactive Map Application. (See "DIMA Quick Fix Endorsed," *PJM OC Briefs: July 9, 2020*.)

Endorsements/Approvals (9:10-10:55)

1. Manuals 14D and 27 – Zonal NSPL Values (9:10-9:25)

Members will be asked to endorse revisions to Manual 14D: Generator Operational Requirements and Manual 27: Open Access Transmission Tariff Accounting that alter the deadlines for adjustments associated with finalizing the zonal network service peak load values. (See "Manual 14D and 27 Revisions," *PJM MIC Briefs: Aug. 5, 2020*.) The Manual 27 revisions were endorsed at the Aug. 5 Market Implementation Committee meeting, while the related Manual 14D revisions were endorsed at the Aug. 6 Operating Committee meeting.

2. Market Efficiency Process Enhancement Task Force (9:25-10:10)

Stakeholders will be provided an update on the Phase 3 work completed at the Market Efficiency Process Enhancement Task Force and asked to vote on several rule changes. (See *PJM Stakeholders Debate Market Efficiency Proposals*.)

A. PJM will review two proposals for creating a new regional targeted market efficiency project (RTMEP) process that transmission owners say will target small projects addressing persistent congestion not identified in the forward-looking planning model, which other members have criticized for excluding competition. Members will be asked to approve American Electric Power's and FirstEnergy's package, A4, which would award RTMEPs to the incumbent TO. If that vote fails, members will be asked to consider PJM's proposal, A1, which calls for 30-day competitive windows to select the developer. The AEP-FE proposal won a 56% Planning Committee vote in May, edging out the PJM proposal, which received 55% support. Members also will be asked to approve corresponding OA revisions.

B. PJM also will seek a vote on the benefit calculation metric for RTMEPs and asked to approve AEP-FE solution package B4, which would average multiple Monte Carlo results and run them on Regional Transmission Expansion Plan (RTEP), RTEP+3 and RTEP+6 years. If that fails, members will vote on PJM proposal B1, which would use a single-draw Monte Carlo simulation, with simulations for both Reliability Pricing Model and RTEP years. The AEP-FE proposal won 54% support from the PC, compared to 52% for PJM's proposal. Corresponding OA revisions also will be up for a vote.

C. PJM will review and seek a vote on PJM package C1 and corresponding OA revisions to clarify when capacity benefits of RTMEPs are calculated.

3. Risk Management Committee Charter (10:10-10:25)

PJM will seek approval of revisions to the Credit Subcommittee charter, which expand its scope to incorporate risk and changes the committee reporting structure. The panel will be renamed the Risk Management Committee. (See "'Credit' Subcommittee Proposed to Change to 'Risk Management,'" *PJM MRC Briefs: April 30, 2020*.)

4. Critical Infrastructure Stakeholder Oversight Senior Task Force (10:25-10:55)

Stakeholders will be asked to revoke an issue charge being worked on at special PC sessions on critical infrastructure stakeholder oversight and endorse a replacement issue charge, which has a related problem statement. (See "Changes Approved to CISO Issue Charge," *PJM PC/TEAC Briefs: May 12, 2020*.) ■

— Michael Yoder

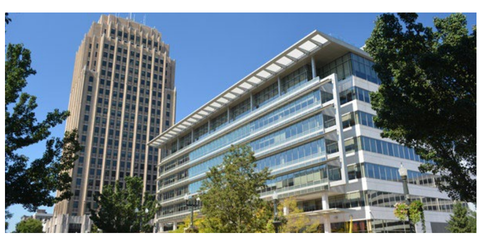
PPL to Sell UK Operations, Focus on US

By Michael Yoder

PPL is looking to sell its U.K.-based utility business and focus on its U.S. operations, company officials announced last week during a second-quarter earnings call.

CEO Vincent Sorgi said in his presentation that the decision to sell Western Power Distribution (WPD) — the distribution utility for parts of England and Wales — followed a "comprehensive strategic review" by the company's board of directors.

Sorgi said PPL believes the divestment of WPD will streamline the company and provide more "financial flexibility," allowing it to concentrate on domestic infrastructure projects and growing clean energy technologies.



PPL's headquarters in Allentown, Pa.

"We believe WPD represents the premier asset group with an extremely high-performing management team in the best energy subsector in the U.K., i.e., electric distribution," Sorgi said. "We are more confident than ever that the road to net-zero carbon emissions in the U.K. will flow through electric distribution. And significant investment will be required in that sector if the U.K. is going to achieve its net-zero goals."

WPD consists of four distribution network operators serving around 8 million customers in central and southwest England and South Wales. Sorgi said a near-term sale would provide the new owner of WPD the opportunity to affect its business plans for the U.K.'s next five-year price control period, which sets the revenue that electric distribution companies can earn from charges on consumer energy bills.

PJM News

PPL to Sell UK Operations, Focus on US

"The decision to sell WPD is in no way a negative reflection on our WPD team or the WPD business; in fact, it's quite the opposite," Sorgi said. "We are extremely proud of the financial and operational results that WPD has achieved over the past two decades, and we are confident they will continue to deliver in the future."

Sorgi said PPL believed WPD that is undervalued by investors and that its sale price should be "higher than the sum of the parts" incorporated into the company's stock price. He also said the sale will allow PPL to target an earnings-per-share growth rate "more in line with our U.S. utility peers."

The company said it expects to begin evaluating offers for WPD's sale, including deals involving all cash or a combination of cash and U.S. utility assets. PPL has chosen J.P. Morgan Securities to serve as its financial adviser to assist with the sale, intending to announce a deal sometime in the first half of 2021.

Sorgi said PPL has been "very transparent" with its investors that the company would not engage in mergers and acquisitions activities unless they could be completed in a way to create value for shareholders. He said the possibility of a WPD deal provided a perfect opportunity.

Earnings down

CFO Joseph Bergstein Jr. announced net income of $344 million ($0.45/share) for the quarter, a 22% decrease from its earnings of $441 million ($0.60/share) in the same period last year.

The company, however, posted a $83 million ($0.10/share) special-item loss "primarily from unrealized losses on foreign currency economic hedges and certain impacts related to COVID-19." Adjusted earnings were actually up slightly for the quarter, from $422 million in 2019 to $427 million this year.

Total revenue for the quarter was $1.73 billion, a 3.5% year-over-year dip. PPL maintained its earnings-per-share guidance for 2020 of $2.40 to $2.60. ■

PJM Monitor Reports Record-low Energy Prices

By Michael Yoder

PJM energy prices were lower in the first half of 2020 than any first six-month period since the creation of the RTO's markets in 1999, according to a report issued Thursday by the Independent Market Monitor.

| Shutterstock

Monitoring Analytics' State of the Market Report for the second quarter said energy prices in the RTO were already among the lowest in its history in the first six months of 2019, coming in at $27.49/MWh. But the report found the load-weighted average real-time LMP was 29.4% lower in the first six months of 2020, at $19.40/MWh.

Monitor Joe Bowring attributed the $8.09/MWh decrease to lower fuel costs, which made up 51.3% of the lower number. The second major contributor to the decline in energy prices cited by the Monitor was a significant decrease in demand because of mild winter temperatures throughout the region and the stay-at-home orders arising from the COVID-19 pandemic.

PJM load was down cumulatively by 5.9% compared to the first six months of 2019, the report said, and down 4.5% on a weather-normalized basis. Energy prices in PJM were set by units operating at or around short-run marginal costs, the report said, providing evidence of "generally competitive behavior and competitive market outcomes."

Theoretical net revenues decreased for all generating unit types in the first half of 2020 compared to 2019 because of lower energy prices, the Monitor said, with theoretical net revenues decreasing by 26% for a new combustion turbine, 29% for a new combined cycle unit, 91% for a new coal unit and 31% for a new nuclear plant.

The trend toward more energy from natural gas and less from coal in PJM continued to accelerate in the first six months of 2020, the Monitor found. The share of total energy produced from coal fell from 24.8% in the first six months of 2019 to 17.6% in 2020, while the share of natural gas increased from 33.8% to 39.4%. The capacity factor of coal units also fell from 30.9% to 22.1%.

Total energy uplift charges decreased by $13.7 million, or 37.3%, from $36.7 million in 2019 to $23 million in 2020, the report said. Total congestion costs decreased by $74.8 million, or 29.4%, from $254.1 million in 2019 to $179.3 million in 2020.

The report said total auction revenue rights (ARRs) and self-scheduled financial transmission rights revenues offset 138.8% of total congestion costs for the 2019/2020 planning period because FTR bidders paid more in the auctions than actual day-ahead payments for the same paths.

The Monitor said the goal of the FTR market design should be to ensure load has the rights to 100% of congestion costs. "When there are binding transmission constraints and locational energy price differences, load pays more for energy than generation is paid to produce that energy" the report said. "The difference is congestion. Congestion belongs to load and should be returned to load." ■

PJM News

FERC Accepts PJM TOs' End-of-life Revisions

Continued from page 1

The existing provisions of Attachment M-3 provide only for the planning of supplemental projects. The TOs' revisions "expand the applicability" of the attachment by requiring each TO to present its criteria for assessing whether a transmission facility needs to be replaced. It also allows for annual stakeholder input in the EOL process.

"Significantly, the proposed revisions provide for coordination of EOL needs with the PJM RTEP planning criteria needs," FERC said in its order. "This provides PJM and stakeholders with increased opportunities to review and comment on EOL need transmission projects, and thus provides greater transparency."

The TOs' filing also said the revisions will "better coordinate the Transmission Owners' end-of-useful-life asset-management activities with PJM's planning to address RTEP planning criteria" by providing the RTO projected replacements up to five years in advance.

As far as asset-management projects cited in the filing, FERC found they "do not fit within the categories of projects the [TOs] have transferred to PJM" and do not fall under regional planning under the OA because they relate "solely to maintenance of existing facilities" and do not "expand" or "enhance" the PJM grid as required in the CTOA to transfer planning to the RTO.

"They are solely projects that maintain the existing infrastructure by repairing or replacing equipment," the commission said. "These projects therefore fall within the category of rights not specifically granted to PJM and therefore reserved to the PJM TOs."

| Shutterstock

Protests

Dozens of PJM stakeholders intervened in the TO filing, some raising concerns that the "majority" of transmission planning in the RTO is happening outside of the bounds of the RTEP process. FERC said the argument was beyond the scope of the proceeding.

Concerns were also raised that the proposed revisions could result in "a cost allocation that is not consistent with cost causation." FERC said provisions of Schedule 12 of the PJM Tariff assign cost responsibility for required transmission enhancements, but the revisions to Attachment M-3 include no revisions to Schedule 12 and propose no cost allocation changes.

Stakeholders, including American Municipal Power and Old Dominion Electric Cooperative, argued that the commission should reject the TOs' filing and accept the joint stakeholder proposal passed by 69% of the Members Committee on June 18 despite the RTO's opposition. FERC ruled that the joint stakeholder proposal was not before the commission in this proceeding and "does not alter the FPA Section 205 filing rights of the PJM TOs."

"We find the PJM TOs' Attachment M-3 revisions filing just and reasonable and need not determine whether proposed alternatives are more or less reasonable," the commission said. "And, again, in this instance, the alternatives mentioned here consist of a filing made in a different proceeding, not this proceeding."

The joint stakeholder proposal would require more transparency and oversight by PJM. The TOs and PJM say it violates the RTO's governing documents and commission precedent on the RTO's and the TOs' roles in the planning of supplemental projects — including EOL facilities — and asset-management projects.

Sharon Segner, vice president of LS Power, said it is "too early to tell" if the commission will reject the joint stakeholder proposal or if both the TO revisions and the stakeholder proposal will be accepted. Segner said FERC's language in its order left open the possibility to both being accepted, with a decision by Aug. 31.

"As a policy matter, LS Power continues to fight for the value of the regional transmission planning proposition, and the FERC order from yesterday is an attack on the value of the regional transmission planning process," Segner said. ■

SPP News

GridLiance, Xcel Battle over Tx Qualifications

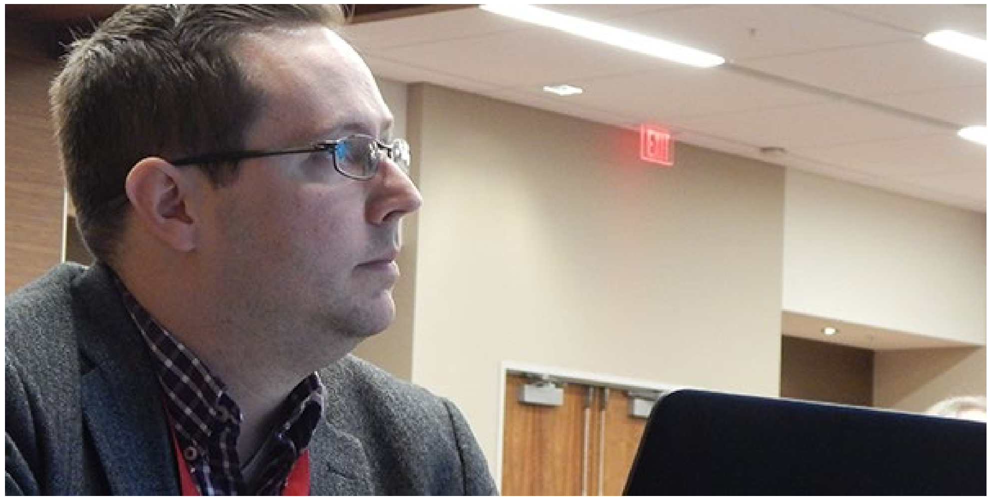
Order 888, SPP Tariff Collide in FERC Settlement Docket

By Tom Kleckner

SPP may have been incorrectly charging transmission customers for their use of certain facilities, GridLiance High Plains says.

The independent transmission operator said a recent FERC ruling in a dispute between it and Xcel Energy Services "calls into question" how the Tariff's Attachment AI has been applied.

Xcel has protested GridLiance's inclusion of its Oklahoma Panhandle facilities in its annual transmission revenue requirement, saying they do not qualify for regional cost allocation under the Tariff and would result in a cost-shift to its Southwestern Public Service subsidiary, which shares the same transmission pricing zone.



GridLiance High Plains President Brett Hooton | © *RTO Insider*

Responding to a certified question from an administrative law judge presiding over settlement proceedings in the dispute, the commission ruled Aug. 7 that qualifying as a transmission facility under Attachment AI does not eliminate the need to pass the seven-factor test established by Order 888 (*ER18-2358, ER19-1357*).

FERC established the test in 1996 to identify which facilities would be under the commission's jurisdiction and what facilities would remain under state jurisdiction in states using unbundled retail wheeling. The test says local distribution facilities are normally low voltage, in close proximity to retail customers and primarily radial. It also says that power flows into local distribution systems, rarely flowing out.

"We find that the seven-factor test may be applied either to classify or declassify any facility as a transmission facility under Attachment AI," FERC said in its Aug. 7 ruling. "Parties are not precluded from seeking a determination from this commission or state commissions to classify or declassify any facility under the … seven-factor test."

"Notably, this order impacts much more than just this case," GridLiance High Plains President Brett Hooton said in a statement. He said the ruling raises questions about Attachment AI "and if transmission customers have been paying SPP rates for facilities that should have been directly assigned to a smaller set of customers."

SPP spokesperson Meghan Sever disagreed, saying the grid operator's interpretation of the order says it has "implemented Attachment AI correctly over the years."

"If an entity wished to challenge the inclusion of facilities into a zonal rate, the challenger has that right before a state commission or FERC using the seven-factor test," she said in an emailed statement.

'Contentious Subject'

The ALJ said the seven-factor test has been a "contentious subject" of prehearing motions in Xcel's challenge to GridLiance's 2019 informational filing on its projected net revenue requirement. The commission ordered the dispute into settlement proceedings last October. (See *FERC Sets GridLiance ATRR Dispute for Settlement*.)

The judge said that GridLiance argues that, based on the commission's clarification in the October 2019 order, the seven-factor test is a fallback used to classify transmission facilities when they fail to meet any of Attachment AI's criteria. Xcel contends that the test's outcome is the ultimate determinant of whether a facility qualifies as a transmission facility under Attachment AI.

The Tariff attachment defines transmission facilities as those that meet any one of six criteria:

- All existing 60-kV or above non-radial power lines, substations and associated facilities and all 60-kV or above radial lines and associated facilities that serve two or more eligible customers not affiliates of each other.
- Facilities used for interconnecting the transmission zones to each other or that interconnect the grid with other surrounding entities.
- Equipment needed to control and protect a facility qualifying as a transmission facility.
- Facilities on the high voltage side of a transformer for a substation transforming from a voltage higher than 60 kV to a voltage lower than 60 kV.
- The portion of DC ties owned by an SPP transmission owner, including the portions operated below 60 kV.
- Facilities operated below 60 kV that FERC has determined to be transmission pursuant to Order 888's seven-factor test.

GridLiance asked that the commission clarify whether the Oklahoma assets qualify as transmission facilities under Attachment AI, and not whether they must also meet the commission's seven-factor test.

Hooton said GridLiance requested the clarification "to simplify and shorten the hearing."

"While we were disappointed in the decision, we remain confident in our case and continue to work to ensure Oklahoma Panhandle ratepayers receive comparable and fair cost allocation," he said. ■

Company Briefs

USEA Mourns Death of Barry Worthington

Barry Worthington, executive director of the United States Energy Association, died Friday at his Maryland home.

"It is impossible to completely articulate the grief we feel at this moment," USEA Chairman Sheila Hollis said in a statement. "We feel his absence acutely; he was our family, our champion. Barry was a remarkable leader, and his absence reverberates among us all."

Worthington had headed USEA, which supports policy and technical discussions with the U.S. Department of Energy to expand the use of clean energy technology globally, since 1988. "Under Barry's leadership, USEA became the central convening force and educational platform in the U.S. energy community, bringing together a spectrum of energy leaders," Hollis said.

He leaves behind his wife, Louise, and their two children, Barry and Kerry.

More: *USEA*

Apex Clean Energy Sells Texas Wind Project

Apex Clean Energy announced last week that it has sold its 500-MW White Mesa wind project in Texas and associated power purchase agreements to an unnamed buyer.

White Mesa is under construction in Crockett County, where it is expected to begin commercial operations next year.

More: *Renewables Now*

Brookfield May Buy Blackstone's Cheniere Stake

Brookfield Asset Management's infrastructure arm is in talks to acquire Blackstone Group's minority stake in LNG terminal operator Cheniere Energy Partners, according to people familiar with the matter. The asset manager is working with a partner to acquire Blackstone's interest, although no final decision has been made and Brookfield could still opt to back out.

Blackstone's 41.2% stake is worth about $7.8 billion, according to Bloomberg.

Cheniere Energy Partners owns the first major US LNG export terminal. Blackstone agreed to invest about $1.5 billion in the company in 2012.

More: *Bloomberg*

Contura Energy to Accelerate Exit from Thermal Coal Business

Contura Energy last week said it intends to speed up its exit from producing coal for electricity in a move it says is tied to the global transition away from fossil fuels.

The largest market for coal has traditionally been thermal coal used in power stations. A smaller market exists for metallurgical coal, which is used in making steel. Company executives said they plan to focus their operations on producing metallurgical coal and expect to be out of the thermal coal business by the end of 2022.

Contura last year exited its thermal coal operations in Wyoming's Powder River Basin. Earlier this year the company announced it is seeking a buyer for its thermal mine in Greene County, Pa., adding that operations will cease by the end of 2022 if a buyer isn't found.

More: *Ohio Valley Resource*

COVID-19 Curbing Corporate Clean-energy Deals

Renewable power contracted by U.S. corporations and public institutions this year will fall short of last year's record-high 13.6 GW, according to a report by BloombergNEF. Procurement of clean energy through July was at 4.3 GW, which was down from 6 GW at the same point in 2019.

Globally, corporations and public institutions procured 8.9 GW of renewable energy through July, slightly ahead of the 8.6 GW signed through July of last year.

More: *Bloomberg Green*

FirstEnergy Says it Needs More Time to File Quarterly Report

FirstEnergy last week told the Securities and Exchange Commission (SEC) it needed more time to file its latest Form 10-Q quarterly financial report, saying it "requires additional time to complete its quarterly review and closing procedures and to provide appropriate disclosure in the Form 10-Q."

The utility said it could not file the form "within the prescribed time period without unreasonable effort and expense" and cited the federal investigation involving former Ohio House Speaker Larry Householder and other subpoenas connected to the investigation.

Publicly traded companies have up to 45 days from the end of the quarter to file their 10-Qs with the SEC.

More: *Akron Beacon Journal*

Mansoor Elected EPRI President, CEO

The Electric Power Research Institute (EPRI) board of directors last week unanimously elected Arshad Mansoor as its new CEO, effective Jan. 1, 2021. Mansoor will replace current CEO Michael Howard, who is retiring. Mansoor will also continue in his role as president.

Mansoor joined EPRI in 2006 as vice president for power delivery and has held numerous leadership positions since. Prior to his current role, he served as senior vice president of research and development.

More: *EPRI*

Ørsted Posts Quarterly Loss

Ørsted posted a quarterly loss last week because of what it called a "sagging power demand." The company also recently lost out to Shell and Dutch utility Eneco in a major Dutch offshore wind tender.

The firm posted a second-quarter loss of $132 million while its revenue fell 29%.

More: *GreenTech Media*

Company Briefs

Sunrun Sees Installations Fall, Stock Rise

Sunrun last week said its second-quarter installations fell 20% compared to the largely pre-pandemic first quarter, with a 24% drop from the 103 MW it installed in the second quarter of 2019.

The company's stock surged in July after it announced plans to acquire its top competitor, Vivint Solar. After starting the year around $14, the stock was trading Monday at nearly $48, an all-time high.

CEO Lynn Jurich said she expects installations to be 20% higher in quarter three than quarter two and approach normal levels by the end of the year.

More: *GreenTech Media*

US Clean Energy Jobs See Modest Gains

The clean energy sector gained 3,200 jobs in July, ending five consecutive months of declines.

Despite the gains, data released by the American Council on Renewable Energy, E2 and other advocacy groups estimated that more than half a million workers remain out of work since the start of the COVID-19 pandemic.

California had the largest surge with 720 jobs. Massachusetts, Texas, Illinois, New York, North Carolina, Michigan, Florida and Colorado each gained more than 100 jobs.

More: *Bloomberg Law*

Xcel Unveils New EV Goal

Xcel Energy last week announced its goal of powering 1.5 million electric vehicles in its service areas by 2030. Building on the company's vision to provide 100% carbon-free electricity by 2050, powering 1.5 million EVs by in 10 years would reduce emissions by nearly 5 million tons annually.

Xcel plans to electrify all sedans in the utility's fleet by 2023, all light-duty vehicles by 2030, and have 30% of its medium- and heavy-duty vehicles electrified by the same year. By 2030, the company estimates, an EV would cost $700 less per year to fuel than a gas-powered car, saving customers $1 billion annually.

More: *Xcel Energy*

Federal Briefs

Critics Urge Utah Cities to Leave Idaho Nuclear Project

The Utah Taxpayers Association and Peter Bradford, a former member of the Nuclear Regulatory Commission, last week urged Utah cities that have signed on with NuScale's small modular reactor in Idaho to get out of their deals as soon as possible before costs become too great.

The 720-MW reactor is planned for construction at the Idaho National Laboratory. It is part of the Carbon Free Power Project, which features 12 modules, with the first scheduled to come online in 2029 and 11 more following the next year. Project spokesman LaVarr Webb said there are several opportunities for cities to exit, one of which is on Sept. 14. The deadline prompted the taxpayers association to urge cities to get out before they are obligated to pay millions for a technology it says is unproven.

The project's design certification is under review by the NRC and must pass several other regulatory hurdles before construction can begin.

More: *Idaho Business Review*

EPA to Lift Obama-era Methane Controls

The Trump administration last week lifted Obama-era controls on the release of methane, however they could be quickly undone in the first half of 2021 thanks to the Congressional Review Act.

The new methane rule eliminates federal requirements that oil and gas companies must install technology to detect and fix methane leaks from wells, pipelines and storage sites. Agency officials said new rule is needed to free the industry from "crippling regulations" when companies are suffering from plummeting prices and falling demand driven by the COVID-19 economic slowdown.

Methane currently makes up nearly 10% of greenhouse gas emissions in the U.S. but has 80 times the heat-trapping power of carbon dioxide in its first 20 years in the atmosphere.

More: *The New York Times*

Former EPA Bosses Call for 'Agency Reset' After Election

Six former EPA chiefs last week called for a "reset" at the agency after President Trump's first term. The former administrators — William Reilly, Lee Thomas, Carol Browner, Christine Todd Whitman, Lisa Jackson and Gina McCarthy — served under Republican and Democratic presidents.

The former administrators endorsed recommendations by the Environmental Protection Network, a bipartisan group of more than 500 former EPA senior managers and employees. The network said the recommendations are meant to guide whichever administration the Nov. 3 presidential election puts in place, though many of the proposals are critical of Trump EPA's actions. The statement did not mention Trump, but said they were "concerned about the current state of affairs at EPA."

Current Administrator Andrew Wheeler rejected the recommendations, with spokesman James Hewitt saying Wheeler's predecessors "botched" environmental matters during their tenures.

More: *The Associated Press*

Union Files Unfair Labor Practice Charge Against EPA

The American Federation of Government Employees (AFGE), the union representing thousands of EPA employees, last week filed an unfair labor practices charge against the agency accusing it of violating employee rights.

Federal Briefs

The union claims Associate Deputy Administrator Douglas Benevento "falsely disparaged and threatened the union and employees" in May. The AFGE said Benevento implied the EPA was unwilling to deal with the union because it shared agency communication with the media "despite the fact that such activity is protected by law."

The union also says Administrator Andrew Wheeler made false statements about bargaining during meetings with regional staff in July when he said the union refused telework flexibility because it wanted more benefits for its leadership.

More: *The Hill*

Groups to Sue DOE over Delayed Efficiency Standard Updates

A coalition of environmental groups and 16 state attorneys general last week filed a "notice of intent to sue" the Energy Department in 60 days over its failure to update 26 energy efficiency standards. The deadline for the DOE to review the efficiency standards for items including water heaters, refrigerators, microwaves and dishwashers go back as far as 2016.

House Energy and Commerce Committee Chairman Frank Pallone Jr. (D-N.J.) said the number of missed legal deadlines for new standards has grown from three to 26 since President Trump took office.

Energy Secretary Dan Brouillette said last month he would complete "as many [rules] as I possibly can" by the end of the year.

More: *The Hill*

TVA Board to Review CEO Salary

Tennessee Valley Authority Interim Chairman of the Board John Ryder said last week the board will review President **Jeff Lyash**'s salary and consider possible changes in its executive compensation packages.

"The issue is not Jeff's performance — everybody agrees he is doing a great job," Ryder said. "There is an issue of compensation that the board is going to take a serious look at and how we structure that so that we are in compliance with the TVA act."

Lyash joined TVA last year and was paid more than $8.1 million during his first six months on the job. The TVA act requires the company to pay competitive compensation with other electric utilities for all of its workers, including its CEO, and relies upon a Willis Towers Watson Energy Services Executive Compensation Database of 28 investor-owned utilities with revenues of more than $3 billion (plus five major government entities) to set Lyash's pay. TVA's CEO salary of $920,000 is more than twice the highest federal salary and has a host of pension and performance bonuses that add millions to the pay package.

More: *Chattanooga Times Free Press*

US Coal Power Generation Plummets in 2020

U.S. coal power generation dropped by 30% in the first half of 2020 after falling 16% in 2019 to a 42-year low, according to the Energy Information Administration. Electricity generation accounts for more than 90% of national coal consumption.

Meanwhile, renewable electricity output rose 5% in the first half of this year to 19% of generation, and natural-gas generation jumped by 9% to 40% in the continental U.S. Nuclear accounted for 22%. EIA suggested coal's decline is largely due to cheaper alternatives. With average monthly Henry Hub natural-gas spot prices down more than 30% and more than 180 GW of wind and solar plants online across the country, coal plants have become "uneconomical in most regions."

More: *GreenTech Media*; *Power Engineering*

White House Withdraws Pendley BLM Nomination

The Trump administration last week withdrew the nomination of **William "Perry" Pendley** to head the Bureau of Land Management. Pendley is the BLM's deputy director for policy and programs and has been the bureau's acting director since July 2019.

White House and Interior Department officials said Pendley would continue to serve in his current deputy director position at the department, allowing him to continue running the agency.

The nomination was controversial because Pendley, former president of the right-wing Mountain States Legal Foundation, once urged the sale of federal lands.

More: *The Washington Post*

State Briefs

CONNECTICUT

Municipal Leaders Mull Legal Action over Eversource's Isaias Handling

Leaders from municipalities with long power restoration times considered legal action against Eversource last week, saying the utility failed to prepare adequately for Tropical Storm Isaias.

Danbury Mayor Mark Boughton said he would consult with other municipal leaders and his legal team "to look at legal action that we can bring against Eversource, its CEO and its senior management team." Meanwhile, the Public Utilities Regulatory Authority is investigating both Eversource's and United Illuminating's response to the storm. A document filed with PURA showed Eversource was anticipating as many as 380,000 outages, but there were more than double that following the storm.

More: *Hartford Courant*

INDIANA

Vectren Seeks Proposals for Wind, Solar Projects

Vectren last week issued a request for proposals for up to 300 MW of wind and up to 1,000 MW of solar paired with storage, to begin operating in 2023. The request is for projects generating a minimum of 50 MW for wind and solar or 12.5

State Briefs

MW for renewables paired with storage.

The need for the renewables was identified in the company's Integrated Resource Plan, which was submitted to the Utility Regulatory Commission in June. State law requires utilities to update the plans every three years.

Only resources capable of firm deliverability to MISO Local Resource Zone 6 will be considered.

More: *Vectren*; *Evansville Courier & Press*

MISSOURI

PSC to Investigate Evergy Standalone Plan

The Public Service Commission last week opened an investigatory docket into Evergy's standalone plan and other related activities in the utility's agreement with Elliott Management.

Elliott manages funds owning a significant share of Evergy's and has pushed the company to shake up its management team and pursue a merger with larger companies. Evergy recently decided to drop those plans and remain a standalone company. (See *Evergy Releases Standalone Plan Details*.)

The PSC wants to investigate the standalone plan to ensure it will not lead to "unnecessarily higher rates or diminished quality of service" for ratepayers. It also wants to assure the company remains compliant with "various agreements and assurances" made during its mergers with Aquila and Great Plains Energy-Westar.

Staff has until Nov. 13 to file its report.

More: *Missouri Public Service Commission*

NEW JERSEY

State Investigating Utility Responses to Tropical Storm Isaias

Board of Public Utilities President Joseph Fiordaliso last week said the agency will conduct a post-mortem investigation into utilities' Tropical Storm Isaias response after complaints from residents and officials about the pace of restorations.

Residents and mayors criticized Jersey Central Power & Light, which provides power to 2 million people, for prolonged waits and poor communication. BPU Commissioner Bob Gordon said companies didn't adequately communicate with customers and pointed to the need for advanced metering infrastructure (AMI).

AMI, which is already in place in other states, enables utilities to detect outages more quickly and dispatch repair crews accordingly. In February, the BPU filed an order that gave the state's four electric companies until Aug. 27 to file plans to implement the technology.

More: *NJ Advance Media*; *NJ Spotlight*

NEW YORK

Con Ed, O&R Fined for Poor Response to Winter Storms in 2018

The Public Service Commission last week fined Con Edison and sister company Orange & Rockland Utilities $10.75 million for their response to the back-to-back March 2018 nor'easters. It is the largest fine ever imposed by the PSC.

Of the $10.75 million, $4.3 million will go toward mitigation measures. The remaining $6.45 million will benefit ratepayers in the companies' next rate cases, with customers asked to provide input on the funds' use. The companies adopted 144 storm plan recommendations made by the PSC.

More: *Rockland/Westchester Journal News*; *New York Public Service Commission*

NORTH CAROLINA

State Denies Key Water Permit for MVP Southgate Pipeline

The Division of Water Resources last week denied a key water permit for the Mountain Valley Southgate Pipeline, saying it determined the proposed natural gas project "is inextricably linked to, and dependent upon, completion of the under-construction Mountain Valley Pipeline," which has several federal permits suspended or pending.

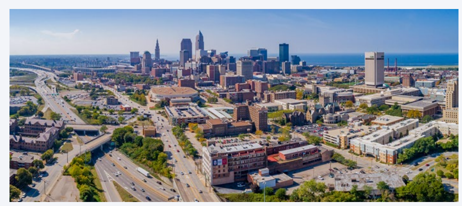
The division denied both a Water Quality Certification and Jordan Lake Riparian Buffer Authorization. The company has 60 days to appeal.

The $468 million project would be a 75-mile extension of the Mountain Valley Pipeline. The "mainline" project originates in West Virginia and crosses Virginia, before its Southgate spur enters North Carolina near Eden.

More: *News & Record*

OHIO

Cleveland City Council OKs Investigation into CPP



The Cleveland City Council last week voted unanimously to launch investigations into whether any parties accused in the statehouse corruption scandal involving bailouts of Ohio's nuclear plants sought to harm Cleveland Public Power (CPP). (See *FirstEnergy, AEP CEOs Deny Wrongdoing*.)

Council President Kevin Kelley, the primary sponsor of the resolution, said he wants the investigation to look at lobbying by FirstEnergy, noting it is a competitor to CPP. At the same time, several members want to scrutinize CPP with the hope making the utility more efficient and accountable.

Mayor Frank Jackson is expected to approve the resolution, which could involve the council's power to issue subpoenas.

More: *Cleveland.com*

State Briefs

WISCONSIN

Appeals Court Says Utilities Can Participate in Permit Challenge

The 7th U.S. Circuit Court of Appeals last week ruled that American Transmission, Dairyland Power Cooperative and ITC Midwest can intervene in a case brought by a pair of environmental groups opposing the $492 million Cardinal-Hickory Creek line. The decision overturned a lower court's ruling, which said the Public Service Commission would defend the companies' interests.

The Court of Appeals ruled that while the PSC can mount a defense of the permitting process, "the power-line project itself, and the permit necessary to construct it, belong to the transmission companies, as does the authority to use eminent domain." Although the commission regulates the companies, it does not advocate for them or represent their interests, the court said. It said the companies cannot be forced to rely on their regulators to protect their investment, which they stand to lose if the plaintiffs are successful.

The Driftless Area Land Conservancy and Wisconsin Wildlife Federation sued the PSC over approval of the transmission line after claiming two commissioners had conflicts of interest and should have recused themselves.

More: *Wisconsin State Journal*