RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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IMM: PJM 2018 Capacity Auction was 'Not Competitive'

Monitor Repeats Call for Change in Offer Cap

By Rich Heidorn Jr.

The results of PJM's 2018 Base Residual Auction were "not competitive" and illustrate the need to change how the RTO sets its capacity offer cap, the Independent Market Monitor said Thursday in its second-quarter State of the Market report.

"The outcome of the [2021/22] Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level," the report said.

In a separate analysis released Thursday night, the IMM calculated that total reve-

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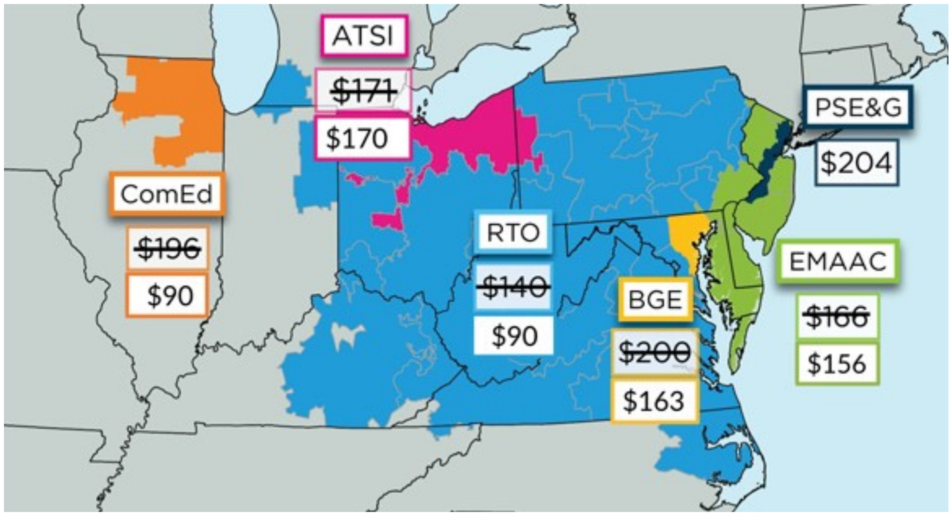

The Market Monitor's analysis found that clearing prices in the 2018 Base Residual Auction would have been lower everywhere but the PSE&G zone had prices been capped at net avoidable cost rate. Not identified is the DEOK zone, which cleared with the rest of the RTO at $140/MW-day but would have priced at $128/MW-day. | *PJM, Monitoring Analytics*

PJM Seeks to Delay 2019 Capacity Auction to August (p.21)

California Wildfire Liability Plan Faces Skeptics

By Hudson Sangree

SACRAMENTO, Calif. — The state's three investor-owned utilities want lawmakers to limit their liability for forest fires sparked by power lines, but the companies' proposal met with stiff opposition Thursday at a capitol wreathed in smoke from fires burning in nearby mountains.

The plan, advanced by Gov. Jerry Brown at the behest of Pacific Gas and Electric and others, calls for the state to change a longstanding rule that holds private and public utilities strictly liable when electric lines cause wildfires. Under current law, the utilities must pay for all destruction of private property through the legal remedy of "inverse condemnation" if their equipment was a substantial cause of a fire.

Brown's plan would still allow suits for inverse condemnation but would require judges to balance the public benefits of the electric infrastructure with

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Wildfires Reshaping Regulator's Role, CPUC Chief Says (p.3)

Western RTO or Bust? Not so, Says Industry

By Michael Brooks

WASHINGTON — Industry opinions vary on the prospects for a full-fledged RTO in the Western Interconnection, with some optimistic and others thinking there are too many snags for it to work.

But that doesn't mean market services can't expand there in some other form, attendees of the Western Power Issues Roundtable said last week.

The 11th annual gathering, held by the Western Power Trading Forum in the offices of law firm Skadden Arps, came after several shakeups in the interconnection this year, including SPP pressing pause on its plan to integrate Mountain West Transmission Group and the announced demise of Peak Reliability. (See *Still 'Committed,'*

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IN THIS WEEK'S ISSUE

This week's issue marks the debut of Hudson Sangree as *RTO Insider*'s new CAISO/WECC correspondent. Hudson joins us following a career in legal trade publications and daily newspapers, most recently *The Sacramento Bee*, where he worked for almost 13 years in a variety of reporting and editing roles. Hudson has a B.A. in legal studies from Hampshire College, in Amherst, Mass., an M.A. in print journalism from Stanford University, and a J.D. from the Northeastern University School of Law in Boston. He lives with his wife and 5-year-old son in Sacramento. You can reach him at hudson.sangree@rtoinsider.com or (916) 747-3595.

Correction

An article in last week's newsletter, *PJM Stakeholders Search for Capacity Rules FERC Will OK*, incorrectly quoted consultants James Wilson and Rob Gramlich as saying they supported an expanded minimum offer price rule (MOPR) in PJM. The story discussed potential responses to a FERC order rejecting two capacity repricing proposals. The consultants said they proposed changes similar to those from PJM and that their plan would make the process "as usable as possible" for states.

CAISO News

Wildfires Reshaping Regulator's Role, CPUC Chief Says

By Hudson Sangree

California's Public Utilities Commission has increasingly focused on wildfire prevention as electric utilities have been blamed for a series of devastating blazes in recent years, the commission's president told state lawmakers last week.

CPUC President Michael Picker said the commission's role had shifted significantly from economic regulation to fire safety during years of high temperatures and low humidity "that result in intense fires with 145-mph winds."

He and others called such conditions the "new normal" in California.

Picker made his comments before a joint committee of state senators and assembly members tasked with ironing out differences in SB 901, which deals with climate change, wildfire prevention and the legal liability of the state's three investor-owned utilities: Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric.

Passed by the State Senate in June, the bill would require a utility's wildfire mitigation plan to describe what factors it will consider when determining whether to de-energize lines in the face of fire danger and include procedures for notifying affected customers. (See *Calif. Senate OKs Utility Wildfire Cost Recovery*.) The mitigation plans are subject to CPUC approval.

The hearing was one of several called to draft a workable bill before the legislature adjourns its two-year session Aug. 31, when the bill would otherwise die.

The conference committee's first hearing was held July 25, when one of its co-chairmen, Sen. Bill Dodd (D), said he was primarily concerned with the safety of residents after hundreds in his Napa County district lost their homes, and some were killed, in the catastrophic wine country fires of 2017.

California Department of Forestry and Fire Protection (Cal Fire) probes have blamed 16 of last year's Northern California fires on "electric power and distribution lines, conductors and the failure of power poles" owned by PG&E.

The nearly 52,000-acre Atlas Fire in Napa, for example, started when a tree limb and a falling tree came into contact with PG&E power lines, Cal Fire said in a June statement. That fire killed six residents and destroyed 783 structures.

PG&E last quarter took a $2.5 billion pre-tax charge for third-party claims related to 14 of the fires.

Opening the July 25 hearing, Dodd said the state needs greater regulation of line maintenance, including vegetation removal, inspection and power shutdowns during extreme weather conditions, "so power lines don't start fires."

He placed part of the blame on the CPUC, alleging lax oversight.

"That means better utility planning and greater accountability for those who operate the grid, including checking compliance before a fire," Dodd said on the dais in July. "That's an area where the CPUC has done quite poorly regulating utilities and ensuring public safety."

Testifying at the same hearing, Picker said the loss of life and homes from wildfires had been keeping him up nights, though he hadn't expected fire-prevention to be a major part of his job.

"I have to say that fires are not something I thought I would deal with when I came to the Public Utilities Commission. But it's obvious they are becoming a bigger and more dramatic issue here in the state of California."

The CPUC in December approved more stringent wildfire standards for utilities, creating a "high fire-threat" district where correction of fire hazards is to be prioritized through improved vegetation management and increased wire-to-wire clearances. (See *CPUC Targets Wildfires, Multifamily Solar, RMRs*.)

The next hearing on SB 901 is scheduled for Aug. 9, when the subject will be the liability of investor-owned utilities for the destruction of private property caused by wildfires.

California Wildfire Liability Plan Faces Skeptics

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the harm caused to private property and to determine if a utility acted reasonably in a particular circumstance. It would also require the utilities to pay proportional damages and not be entirely responsible if others were also at fault.

In addition, the proposal requires utilities to submit wildfire mitigation plans and to harden their grids with upgraded equipment more resistant to weather and fire damage.

Last year's infernos in California's famed wine country and the Sierra Nevada foothills resulted in billions of dollars in damage to homes, vineyards and businesses. The current fire season, which is less than half over, appears to be keeping pace.

At Thursday's hearing, some lawmakers said the proponents' timing couldn't have been worse. The largest fire in state history, the Mendocino Complex Fire, raged in the coastal mountains north of San Francisco, and another major fire had closed Yosemite National Park during the peak of the summer tourist season.

The smoke from the fires turned the air in Sacramento into a yellowish haze.

"I don't know if you noticed, but there's smoke in the air," State Assemblywoman Eloise Gomez Reyes told James Ralph, chief of policy and legal affairs for the California Public Utilities Commission. Ralph presented the governor's plan on behalf of his boss, CPUC President Michael Picker.

Brown originally sent his proposal in writing to the legislature on July 24 with the understanding that it would be part of SB

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California Wildfire Liability Plan Faces Skeptics

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901, a measure dealing with wildfire prevention. To take effect, the bill must clear the legislature by the end of August, when lawmakers adjourn at the end of a two-year session.

To that end, members of the State Senate and Assembly have held a series of conference committee hearings — on July 25, Aug. 7 and Aug. 9 — to take testimony and gather information. Powerful interests on both sides have argued for and against the proposal.

New Normal

Among those fighting the plan are ratepayer groups, the state's trial attorneys, insurers, farmers, and cities and counties. They all stand to lose financially if the utilities are given what some call a bailout.

The utilities — PG&E, San Diego Gas & Electric and Southern California Edison — argue multibillion-dollar payouts threaten their financial stability, undercut fire-prevention efforts and result in rate hikes for consumers.

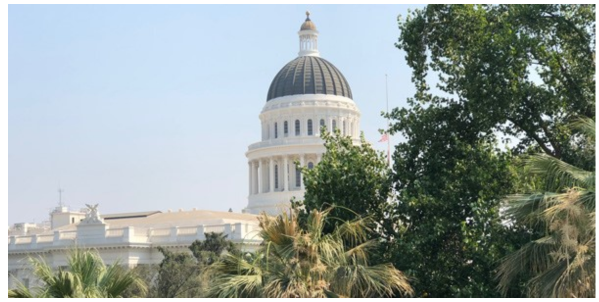
Last year's fires, which among other damage wiped out a large area of the city of Santa Rosa, caused destruction on an unprecedented scale. Many in California attribute such long and destructive fire seasons to climate change and say they are the "new normal." (See related story, *Wildfires Reshaping Regulator's Role, CPUC Chief Says*, p??.)

That makes the utilities nervous because they tend to receive much of the blame and pay most of the costs.

So far, investigators with the California Department of Forestry and Fire Protection (Cal Fire) have concluded that 16 of last year's Northern California fires were caused by trees or branches hitting PG&E power lines, along with a power pole failure and a conductor that crashed to the ground.

Eleven of the 16 cases have been referred to county prosecutors to review for possible criminal violations of a state law that requires adequate clearance between power lines and vegetation, according to Cal Fire news releases in May and June.

Altogether, the fires killed 18 residents, destroyed nearly 3,000 structures and burned more than 180,000 acres. The cause of dozens of other blazes, in what Cal Fire calls the "October 2017 Fire Siege," remain under investigation.



California State Capitol | © *RTO Insider*

'Insurers of Last Resort'

The financial fallout for PG&E is huge. Last quarter the company posted a net loss of $1 billion and took a $2.5 billion pre-tax charge for third-party claims related to 14 of the fires. Fitch Ratings downgraded the company's stock in February, estimating that it could face $15 billion in liability over the next 10 years.

The amount is so massive because California is the only state that relies on inverse condemnation to hold utilities primarily liable for wildfire damage, even when the companies complied with all safety requirements and were only partly to blame for fires.

The current law unjustly "makes utilities the insurers of last resort," Henry Weissmann, a lawyer for Southern California Edison, told the legislative panel Thursday. He said utilities should be held to a negligence standard of liability, which would require proof of wrongdoing, rather than facing strict liability, which does not.

Weissmann said utilities still would have an incentive to prevent fires under the less-stringent standard because they would continue to be subject to lawsuits and government oversight.

Jan Smutny-Jones, CEO of the Independent Energy Producers Association, told lawmakers that the state's progress in sourcing energy from geothermal, solar and other sustainable power producers was threatened by California's insistence that utilities, and ultimately ratepayers, foot the bill for catastrophes.

"All of this is predicated on the financial stability of the companies," he said. "If a utility goes broke ... that's a significant impact."

Freeing up funds for fire prevention would lead to a safer state, proponents argued.

Skeptics, however, said they found it hard to believe that utilities would behave more responsibly if their potential costs were lessened.

Sen. Hannah-Beth Jackson noted that one rationale behind inverse condemnation is that utilities are given the power of eminent domain for easements on private property. They are therefore fully liable for damage to private property, she said.

"Shouldn't we expect you'll do everything possible to protect our property?" Jackson, also a lawyer, asked a panel of utility executives and advocates.

Another major goal of California's policy has been to make wildfire victims whole as quickly as possible without subjecting them to years of litigation to determine negligence. Applying a strict liability standard skips that fight and moves the parties directly to the issue of damages, Jackson said.

The lawmaker said she had trouble grasping how holding the utilities to a lesser standard of liability would increase public safety, as they contend.

"Why should we reduce their liability and expect they're going to do more with less liability?" Jackson asked. "I don't understand the logic here."

The committee's next hearings are scheduled for Aug. 14 and 16. The agendas for those hearings and other materials will be posted online at http://focus.senate.ca.gov/wildfirecommittee.

CAISO NEWS

Western RTO or Bust? Not so, Says Industry

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SPP Halts Mountain West Integration Effort and Peak Reliability to Wind Down Operations.)

SPP's efforts took a hit in April when Xcel Energy's Public Service Company of Colorado (PSCo) subsidiary, representing 40% of Mountain West's load, said it would leave the group. Peak, the reliability coordinator (RC) for most of the interconnection, had been attempting to create a new energy market in partnership with PJM. But in July it said would shut down as early as next year after CAISO moved to leave and provide its own RC services, attracting interest from nearly all of Peak's customers by offering lower-cost services.

Kenna Hagan, senior manager of planning, policy and strategy at Mountain West member Black Hills Corp., said Xcel's announcement, made late Friday, April 20, "floored many of us." She said she called PSCo on Monday morning, saying, "'I'm just checking to see if your executives were participating in Colorado's state holiday.'"

Arnie Quinn of Vistra Energy (left) speaks with WPTF Executive Director Scott Miller. | © RTO Insider

| © RTO Insider

But she assured attendees that Mountain West "is not dead." She said group members are still examining the costs and governance structure of joining SPP without Xcel, but the current priority for everyone in the interconnection, not just Mountain West, is finding a new RC provider. CAISO has said most of the interconnection have signed letters of intent with it, but Hagan said at least two balancing authorities have pledged with SPP.

"I don't think you can underestimate the time, creativity and effort that it takes to

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CAISO News

Western RTO or Bust? Not so, Says Industry

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solve" the issues related to integration, Hagan said.

Stu Bresler, PJM senior vice president of market operations, said that though it has ended its relationship with Peak, "to the extent that there is a desire for folks in the West to continue talking about the possibility of developing their own market, we're still interested in being involved."

The plan remains the same as before Peak's end: provide energy, ancillary and financial transmission rights markets. Then, should members "want to go down the path of an RTO," expand to transmission and interconnection planning.

"We certainly are not saying it's now or never," Bresler said. "If now is not the right time to look at this, PJM is certainly not going anywhere."

All Eyes on California

CAISO has also suffered setbacks in its efforts to expand, but those plans now appear closer than ever to becoming a reality.

A bill that would allow the expansion, AB813, passed the California State Assembly last year, and it's now before the State Senate's Appropriations Committee after passing two other committees in June. (See CAISO Regionalization Bill Edges Toward Senate Vote.)

"We are still very optimistic about 813 passing this year," said Phil Pettingill, CAISO regional integration director. The two-year

John N. Estes III, of Skadden Arps, gives the keynote address during lunch. | © RTO Insider

legislative session ends at the end of this month. If the bill passes the Senate before then, "it's just a matter of the two houses reconciling it and sending it to the governor."

But many at the conference expressed skepticism that CAISO would become an RTO, even if the bill passes. The bill would only allow CAISO to expand if it agrees upon a modified governance structure — and at least one transmission owner outside the state agrees to join — before the end of the year.

Some in the West are concerned that a new RTO would be subject to California's influence more than any other state's. California has been one of the most aggressive in the U.S. in trying to curb carbon emissions and address climate change, while states such as Wyoming and Utah still heavily favor coal.

Former FERC Commissioner Tony Clark, senior adviser at Wilkinson Barker Knauer, wondered, even with "the most independent board you could possibly imagine ... can you still get to a broader regional market, because you still have the inherent tensions between competing state public policies, state mistrust of each other... Maybe the [Energy Imbalance Market] is as far as we get."

Wyoming Public Service Commission Chair Bill Russell said, "It's probably a bigger risk for California than it is for the rest of us. I think California would be giving up more than the rest of us, and I don't know if that happens."

He noted that California wants to offload its abundance of renewable energy. "California is trying solve a problem. ... We are open to the idea of an RTO, but for us, it's just an option. We're not trying to solve a problem."

Russell opened the roundtable by admitting that "everyone in this room knows more about [RTOs] than I do." When PacifiCorp told the PSC it was working with CAISO on expansion in 2015, none of the commissioners had even heard of RTOs, he said.

Now, he said, they are watching CAISO, SPP and PJM very closely. Given the concerns over governance, "the best solution for the West might be two markets, or three, that have various comfort levels for whoever's doing those markets," Russell said.

ERCOT NEWS

PUCT Continues Review of Potential Market Improvements

Texas regulators last week issued requests for comments on real-time co-optimization (RTC) and incorporating marginal losses into dispatch decisions, proposals that have varying levels of stakeholder support.

On June 29, ERCOT's Independent Market Monitor filed a report at the Public Utility Commission indicating RTC could have saved as much as $257 million in reduced congestion costs and $155 million in reduced ancillary service costs during the 2017 test year.

IMM Director Beth Garza told ERCOT's Board of Directors on Aug. 7 that a significant cost of providing operating reserves is the lost opportunity cost of providing energy.

"The cost of containing those reserves, setting them aside, is the lost opportunity of selling that energy," Garza said. "When initially selected in the day-ahead market, the costs of providing both energy and reserves are minimized. That is, co-optimized."

During their Aug. 9 open meeting, the commissioners approved a set of questions as part of its review of RTC (Project No. 48540). They also approved a second group of questions related to incorporating marginal losses' costs into dispatch (Project No. 48539).

A second report, filed by ERCOT, found the grid operator would benefit from RTC through its more efficient procurement of ancillary services and congestion management, and reduced reliability unit commitments.

The IMM and ERCOT will host a technical workshop on RTC and marginal losses Sept. 6.

The PUC held a pair of workshops last year following a report coauthored by Harvard University's William Hogan and FTI Consulting's Susan Pope that recommended rule changes to address intermittent renewables and add incentives for generators. (See *ERCOT, Regulators Discuss Need for Pricing Rule Changes*.)

The PUC also published a list of questions on the review and approval of substations. It has scheduled an Oct. 4 workshop on the subject (Project No. 48251).

Commissioners (left to right) Shelly Botkin, DeAnn Walker and Arthur D'Andrea discuss market improvements during the PUCT open meeting.

Commissioners Approve Tweaks to Retail Website

The commissioners approved staff's suggested recommended changes to the PUC's Power to Choose website, where consumers in Texas' competitive areas can shop for electricity providers. The website has drawn the commission's attention following consumer complaints of pricing gimmicks that result in unexpectedly high costs.

"We've been here before," Commissioner Arthur D'Andrea said. "The commission thought we fixed this website, and now here we are again. I don't want to be back here in two years doing the same thing."

"Unfortunately, I think we may be because REPs [retail electric providers] adjust," Chair DeAnn Walker said. She had reason to be pessimistic, saying she had recently met with a retail representative.

"People are already trying to figure out how to get around these" rule changes, Walker said.

Staff's proposal adds a filter to weed out plans that offer low average prices at the 1,000-kWh usage level, when they cost significantly more for customers who average more than 1,000 kWh/month. The recommendations will also limit the number of offers a REP can list on the website to prevent them from "flooding" a page.

"Doing so will encourage REPs to use [their] available postings wisely, rather than repeating very similar offers to strategically dominate search results," staff said.

PUC to Intervene in FERC Entergy Dockets

Following an executive session, the commissioners agreed to intervene in five dockets at FERC involving Entergy Services and cost-reimbursement agreements with its five operating companies (ER18-2079, *et al.*).

Entergy proposed last year to recover $5.9 million from Texas retail rates for Entergy Texas' portion of construction costs for a pair of transmission control centers it built in Arkansas and Mississippi.

FERC set the agreements for settlement proceedings in February, but the company said the negotiations between Entergy Service its operating companies, commission staff and other parties were not "fruitful" and further discussions "would not resolve the issues in these proceedings." The company filed cancellation notices for the reimbursement agreements with the commission in July. Entergy said no payments were made and no benefits received under the agreements.

— Tom Kleckner

ERCOT NEWS

Board of Directors Briefs

Board Approves Price Correction for July Market Event

ERCOT's Board of Directors last week approved an ISO request to correct real-time prices following a July event that caused brief market palpitations. (See "Stakeholders, Staff Discuss Price Investigation Notices," *ERCOT Technical Advisory Committee Briefs: July 26, 2018*.)

The correction changes 25 security-constrained economic dispatch intervals and nine settlement intervals between 4:30 and 6:30 p.m. on July 18. The average revision across all settlement points was a $10.67/MWh decrease, while the average change in 15-minute settlement price points was a $8.78/MWh decrease.

The ISO was required to seek board approval for the price correction when staff missed a two-business-day deadline to correct the July 18 error on their own.

A data-input mistake in ERCOT's weekly operational model resulted in two double-circuit contingencies on a 138-kV line east of Dallas being identified as two triple-circuit contingencies. Kenan Ogelman, ERCOT vice president of commercial operations, said the contingency bound when it shouldn't have, restricting nearby generation and affecting both system prices and prices near the generating units.

The issue, which wasn't caught until July 19, affected the July 18 real-time operating day and the July 20 day-ahead operating day. Corrected day-ahead prices were published on July 23.

Woody Rickerson, ERCOT vice president of grid planning and operations, said staff have changed the operational model's automated process to avoid similar mistakes in the future. Each model includes about 7,000 contingencies.

"We fixed the problem; we've validated the contingency files; we're moving forward with the same process," Rickerson said.

Staff Continues Southern Cross Work

Compliance Director Matt Mereness briefed the directors on ERCOT's progress in accommodating the Southern Cross Project (SCT), a 2-GW DC tie in East Texas that would connect the ISO with SERC Reliability Corp.

Because ERCOT's largest existing DC tie is 600 MW, Texas' Public Utility Commission last year directed the grid operator to address several issues as a condition for energizing SCT, asking it to respond to 14 directives (Project No. 46304).

Mereness said ERCOT has begun work on six of the directives and is engaging members through the stakeholder process. Two other directives are updates to the PUC and are ongoing.

The board approved staff's recommendation that no protocol or binding documents concerning primary frequency response are necessary in determining whether SCT or any other entity scheduling flows across the tie should be required to provide or procure the service.

The project is scheduled to be energized in 2023.

ERCOT Reports $16.7M Net Revenue Favorable Variance

Bill Magness

ERCOT CEO Bill Magness told the board the ISO's revenues continue to be favorable, thanks mostly to the record demand this summer.

"It's load and weather that drives ERCOT," he reminded the directors.

Magness reported system administration fees were $5 million overbudget through June because of the weather and Texas' stronger economy. Including $4.2 million in interest income, the ISO is $16.7 million above its year-to-date projected net revenues.

Staff is projecting a year-end total of $19.8 million in favorable net revenues.

ERCOT has also made "significant progress" on a delayed congestion revenue rights software update, Magness said. He said the project is scheduled to be completed in September, now that communication has been improved with the vendor and a better process for managing bug fixes is in place.

Special Membership Meeting to be Set

The board voted to call a special meeting of ERCOT's corporate members "as soon as reasonably practicable" to hold votes on amendments to the ISO's Articles of Incorporation, which has been renamed the Certificate of Formation, and to the bylaws, which clarify the definition of affiliates and affiliate relationships. The board unanimously approved both sets of amendments.

The members' annual meeting isn't until Dec. 11, but ERCOT's legal department wants to ensure the amendments are effective for the 2019 membership year.

The directors also approved the 2019 schedule for board meetings and accepted a favorable audit report on ERCOT's employee 401(k) plan.

Board Clears 15 Change Requests

The board unanimously approved its consent agenda, which included a Nodal Protocol revision request (NPRR) it had remanded back to the Technical Advisory Committee in June.

NPRR847 incorporates an intraday weighted average fuel price into the mitigated offer cap. It unanimously cleared the TAC in May, but the board sent it back over concerns that the calculation of blended fuels was "vague and confusing." (See "Board Approves 8 Change Requests," *ERCOT Board of Directors Briefs: June 12, 2018*.)

The measure is intended to ensure resources are capped at the appropriate cost during high fuel-price events and that LMPs reflect the true incremental cost of fuel.

Director Nick Fehrenbach, who represents the commercial sub-segment within the consumer market segment, said he was satisfied with the language changes. He thanked ERCOT for taking his comments

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ERCOT NEWS

Plentiful Generation Helps ERCOT Meet Extreme Demand

By Tom Kleckner

ERCOT executives said last week that system generation overperformed during the early summer months, helping the grid operator meet demand during July's record heat and loads.

"We saw a real test of the system," CEO Bill Magness told the ISO's Board of Directors during its Aug. 7 meeting. "The fleet performed well, and everyone in the market was very aware of what was coming and what we needed to do. It was a good testament to how the participants in the market can perform and how they worked in a stressed situation."

ERCOT, which manages about 90% of the Texas grid, set a new systemwide peak of 73.3 GW on July 19, breaking the record set in August 2016 by more than 2 GW. Its new weekend demand record of 71.4 GW on July 22 also broke the old mark of 71.1 GW.

Date	Time	Peak Usage
7/19/18	4-5 p.m.	73,259
7/23/18	4-5 p.m.	73,059
7/23/18	3-4 p.m.	73,041
7/20/18	4-5 p.m.	72,926
7/20/18	5-6 p.m.	72,700
7/19/18	3-4 p.m.	72,691
7/23/18	5-7 p.m.	72,634
7/20/18	3-4 p.m.	72,300
7/18/18	4-5 p.m.	72,192
7/23/18	2-3 p.m.	72,033
7/22/18	5-6 p.m.	71,444
7/18/18	3-4 p.m.	71,438
7/23/18	6-7 p.m.	71,271
7/20/18	6-7 p.m.	71,212
8/11/16	4-5 p.m.	71,110

Top 15 ERCOT demand records | *ERCOT*

All told, demand exceeded the old record during 14 intervals over July 18-23. Demand exceeded 70 GW between July 16 and 24 as a dome of high pressure settled over the state and sent temperatures into triple digits and some heat indexes to about 110 degrees Fahrenheit.

Staff this spring projected a summer peak of 72.97 GW in August.

Having plenty of generation to call on was key, said ERCOT Senior Director of System Operations Dan Woodfin. He noted generation outages in July were "significantly lower" than what the grid operator has historically seen.

ERCOT began the summer with 78.2 GW of available capacity and added 612 MW of gas generation in July. Wind power averaged daily output of 6.6 GW in July, above pre-summer expectations of 4.1 GW, and accounted for 10.4% of all energy produced during the month, according to the ISO's latest demand and energy report.

"The peak day, the 19th, the outages were

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Board of Directors Briefs

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into consideration.

The consent agenda also included seven other NPRRs, a revision to the Nodal Operating Guide (NOGRR), two changes to the Planning Guide (PGRRs), an update to the Resource Registration Glossary (RRGRR), a system change request (SCR) and two changes to the Verifiable Cost Manual (VCMRR).

- NPRR856: Clarifies that for day-ahead make-whole settlement purposes, the "offline but available for SCED deployment" status is considered an online status and will be considered an offline status after system implementation.
- NPRR862: Incorporates a number of revisions addressing recent changes made by the PUC's rulemaking related to reliability-must-run service (Project No. 46369).
- NPRR866: Addresses two objectives related to mapping registered distributed generation and load resources to transmission loads in the network operations model by codifying the existing process for mapping a load or aggregate load resource to its appropriate load point in the model; and by outlining how to map a registered DG facility to its appropriate load point in the model.
- NPRR873: Outlines expectations for posting information pertaining to intra-hour wind power and load forecasts on the Market Information Systems public area. The NPRR also proposes two new definitions and acronyms for the intra-hour wind power and intra-hour load forecasts (IHWPF and IHLF, respectively).
- NPRR874: Changes the "net allocation to load settlement" stability report by breaking out the load-allocated CRRs monthly revenue zonal amount from the other load-allocated charges, and by providing dollars per megawatt-hour by congestion management zone.
- NPRR875: Adds clarifying language to sync the protocols with NPRR864, which modifies the reliability unit commitment engine to scale down commitment costs of fast-start resources with less than one-hour starts.
- NPRR877: Allows for use of actual metered interval data for initial settlement of an operating day for electric service identifiers that currently require BUSIDRRQ load profiles.
- NOGRR174: Harmonizes the automatic voltage regulator and power system stabilizer testing requirements with the recently approved NERC Standard MOD-026-1.
- PGRR061: Includes locations for registered DG facilities in the annual load data request process.
- PGRR062: Proposes new processes, communication and document sharing and storage requirements to be included in the new generation interconnection or change request application.
- RRGRR017: Supports NPRR866 by providing a process for mapping registered DG facilities to their appropriate load points in the network operations model.
- SCR796: Modifies the Market Manage-

Continued on page 10

ERCOT News

Plentiful Generation Helps ERCOT Meet Extreme Demand

Continued from page 9

almost 2,000 MW less than on the peak day last year. We saw that pretty consistently over that period," Woodfin said. "The cooler weather that we've had the last couple of weeks has allowed the units to regroup and fix some things."

The availability of generation helped minimize tight conditions and keep prices stable. Forward contracts for August delivery reached $239/MWh in May, but fell back to less than $75/MWh in early August.

Kenan Ogelman, ERCOT's vice president of commercial operations, said the operating reserve demand curve (ORDC) has worked as designed. The ORDC creates a real-time price adder reflecting the value of available reserves; it is meant to incentivize resources to produce more energy and reserves.

"The pricing outcomes we've seen in the market are associated with expectations," Ogelman said. "The incentives are also there to put power online, at the times they're needed."

He said congestion in the West region, driven by high load growth and combined with the way ERCOT produces load distribution factors, did lead to more than $30 million in uplift costs in June alone. "Wow!" one board member near an open mike exclaimed.

Staff shared operational data from May and June but promised additional information during the board's October meeting.

"We're pleased with how it all went, but it's only Aug. 7," Magness reminded the board. "We have a lot more August and September to go."

Below-normal temperatures and rain have helped cool things off over the last week.

"This week has sort of been a dud, and next week won't be much different," said the ISO's senior meteorologist, Chris Coleman. He said "there's always an opportunity" that extreme heat will return in the next three or four weeks.

Board of Directors Briefs

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ment System's validation rules for bids and offers to exclude resource nodes within a private-use network site as valid settlement points for day-ahead market energy-only offers and bids, and for point-to-point obligation bids.

- VCMRR021: Aligns the VCM with the language proposed in NPRR847 by removing references to make-whole payments for exceptional fuel costs. The costs will be recovered in NPRR847.
- VCMRR022: Directs ERCOT to contract a coal index price with a fuel vendor and includes a methodology for calculating the quarterly fuel adder for coal-fired and lignite-fired resources based on that index.

– Tom Kleckner

ISO-NE NEWS

Salem Harbor Operator Seeks Dismissal of 'False Offer' Case

By Rich Heidorn Jr.

Salem Harbor Power Station | *Tetra Tech*

The owners of Salem Harbor Power Station have asked FERC to dismiss allegations that the plant misled ISO-NE with supply offers it could not meet because of insufficient fuel.

FERC's Office of Enforcement filed an Order to Show Cause on June 18, saying that owners Footprint Power should forfeit more than $2 million in capacity payments Salem Harbor Unit 4 received for a period in June and July 2013 during which the plant's fuel supply prevented it from operating at its offered capacity. Enforcement also sought $4.2 million in civil penalties. (See *Salem Harbor Plant Facing FERC Action*.)

In its Aug. 2 response, Footprint's attorneys said Enforcement "overstates" what ISO-NE expected from the plant, claiming the RTO was aware that NO_x emissions limits prevented it from running at full capacity for an entire day. Enforcement also failed to consider the time it took the plant to reach full output from start-up, the attorneys wrote in a 383-page answer that includes audio recordings of conversations between plant and ISO-NE operators and a passage from Joseph Heller's "Catch-22" (IN18-7).

"The day-ahead offers reflected [the plant's fuel] limitations. And as the taped phone calls show, the operators repeatedly caveated their estimates about potential availability as uncertain," they wrote.

Footprint said Enforcement overstated the maximum amount of fuel the plant could burn by more than 82%. Enforcement staff did not interview plant operators and there is no evidence investigators talked with the RTO's operators about their expectations, Footprint said.

The company also said Enforcement's calculations understated the amount of fuel the plant had available to burn.

"Enforcement thus offers a conundrum where every option is a violation. If Salem

Continued on page 12

ISO-NE News

Salem Harbor Operator Seeks Dismissal of 'False Offer' Case

Continued from page 11

Harbor offers what it considers to be a good estimate of the projected output of Salem Harbor, that is deceptive because the projection is higher than anything empirically proven to be available in advance. If Footprint offers a lower level of output from Salem Harbor, but one that has been empirically proven to be available in advance, that is physical withholding. This is no idle, after-the-fact thought. The principals of Footprint were veterans of the business and regulatory landscape facing New England independent power producers. They understood the regulatory environment in ISO-NE as well as anyone. And they actually were concerned at the time that under-offering Salem Harbor 4 could expose them to withholding claims."

The filing acknowledges Unit 4 ran low on fuel in July 2013 but noted that the plant was then less than a year from retirement. "Fuel oil had to be bought in large amounts — a barge of oil cost over $5 million in the summer of 2013. And given that the plant historically ran very infrequently, much of that money might end up wasted." Unit 4 retired less than a year after the period in question, and it and its fuel tank have since been demolished.

Footprint said Enforcement is attempting to penalize it for running low on fuel because the plant was not hit with ISO-NE's shortage-event penalties. "If the commission wants to create greater incentives to store fuel oil on site, it obviously can do that prospectively by changing the definition of shortage events in the ISO-NE Tariff so that they occur more frequently. The commission in fact approved just such a change in late 2013. But the commission cannot lawfully change the Tariff to make shortage events more frequent looking backwards. … Viewing things from a broader perspective, the Pay-for-Performance capacity model is not going to work as intended if Enforcement gets to pile on its own chosen sanctions, above and beyond shortage-event penalties, whenever it thinks alleged performance limitations somehow have not already been sufficiently punished."

Footprint also said the case should be dismissed based on the five-year statute of limitations. It disagreed with Enforcement's prior claims that the issuance of a show cause order within five years is sufficient.

It requested a meeting with the commissioners and senior staff to discuss its defense, "with or without Enforcement present."

MISO NEWS

MISO IMM Voices Market Concerns, Commends Competitive 2017

By Amanda Durish Cook

CARMEL, Ind. — MISO's market was competitive in 2017, but the RTO should do more to address increasing congestion and low capacity prices, Independent Market Monitor David Patton told stakeholders last week.

Patton said potential economic withholding throughout the year was low, at about 0.11% of load, with market power mitigation rarely necessary.

"The offers we're getting and the market outcomes are very competitive," Patton said in a 2017 post-mortem during an Aug. 9 Market Subcommittee meeting, part of his annual State of the Market report. In late June, he recommended seven new market revisions from the report to the Board of Directors. (See *7 New Recommendations from MISO IMM*.)

Patton said MISO's 2017 peak load of about 121 GW was comparable to the nearly 120-GW peak in 2016 and below the forecasted 125-GW peak. However, congestion costs last year still rose 7% to $1.5 billion, in part because of higher natural gas costs for frequently dispatched gas units.

Patton said four key factors have increased MISO's costs of managing congestion.

Factor 1: Lack of Market-to-Market Testing

Patton faulted MISO for not requesting testing from other markets to define market-to-market (M2M) constraints for congestion management. He said his team identified almost 170 chronically binding constraints costing $240 million in 2017 that were never classified as M2M, "generally because MISO did not ask for testing."

"Most of those dollars are because MISO didn't ask for the test from either PJM or SPP," Patton said. "When you don't define market-to-market constraints with your neighbors that are impacting them, then you're basically subsidizing their flows on the constraint. You don't go through the settlement process that would bill them for the constraint."

Patton acknowledged that MISO put a tool in place in January to screen for potential constraints, but he said his team has not yet assessed the results of the new practice.

Factor 2: Keeping the Current Pseudo-tie Construct

Patton again leveled his aim at the pseudo-tie process and said PJM's dispatching of MISO resources has to date resulted in 95 new M2M constraints and $155 million in congestion on those constraints.

"It's no surprise that we think PJM's Tariff … shows a lack of understanding of how to run an electrical system," Patton said, adding that PJM cannot effectively model all constraints in the day-ahead market and is overscheduling flows on the MISO system.

Patton said MISO should deny new pseudo-tie requests, and his firm, Potomac Economics, currently has a FERC complaint pending against PJM's pseudo-tie construct. (See *PJM: MISO Monitor Lacks Standing in Pseudo-tie Complaint*.)

"We think it's unfortunate that FERC hasn't figured out how bad this is yet," Patton said, adding that there are other ways for MISO to deliver PJM's purchased capacity without giving it dispatch control over resources located in MISO. He said he hoped more MISO market participants would come out in public support of the complaint.

Factor 3: Need for Increased Outage Coordination

Patton said transmission and generation outages occurring simultaneously on the same constraint have contributed to $400 million in congestion to date — more than 30% of all of MISO's real-time congestion.

"What this points to is the need to give MISO more authority in denying or approving outages," Patton said. "In some cases, MISO is the only one that can coordinate these because of the lack of communication between generation and transmission."

Greater outage coordination is an ongoing discussion in MISO's larger effort around resource availability and need currently being discussed in its Reliability Subcommittee. (See *MISO Moving to Combat Shifting Resource Availability*.)

Factor 4: Incomplete Facility Ratings

Patton said most MISO transmission owners don't adjust their facility ratings to reflect ambient temperatures and wind speeds. He said adjusted facility ratings could have saved MISO as much as $127 million in production costs in 2017.

"If transmission owners submitted dynamic ratings to MISO, we'd have much more transmission capability," Patton said.

Capacity Auction

Patton also said MISO's capacity auction design is causing capacity prices to remain "inefficiently low." The 2018/19 auction resulted in almost all local resource zones clearing at $10/MW-day, while the 2017/18 auction resulted in a single clearing price of $1.50/MW-day. (See *MISO Clears at $10/MW-day in 2018/19 Capacity Auction*.)

Had MISO implemented a sloped demand curve design in its auction, Patton estimated that auction clearing prices would have been $115.74/MW-day in all zones in the 2017/18 planning year and $111.06/MW-day in nearly all zones for the 2018/19 planning year. He said MISO's competitive suppliers stand to benefit the most from a sloped demand curve.

Patton said MISO lost 2.6 GW of capacity on net in 2017 owing to a flawed capacity auction design, "persistent" low natural gas prices that suppress energy prices and environmental regulations "requiring costly retrofits for certain resources."

MISO Response Timed to Market Roadmap

MISO Executive Director of Market Operations Shawn McFarlane said the RTO is still preparing its required response to the Monitor's observations and recommendations.

He said this year MISO will align its written response with the release of the RTO's Market Roadmap list of market improvements to its board. MISO will publicly post a written response in October, present the response at the November Market Subcommittee meeting and discuss it with the board at the December meeting of its Markets Committee.

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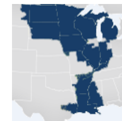
MISO NEWS



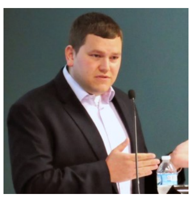
MISO Promises External Capacity Zones After FERC Rejection

By Amanda Durish Cook

CARMEL, Ind. — MISO said last week it plans to refile a plan to create external capacity resource zones with FERC by the end of the month.

And the RTO still promises to make zone determinations in time for the 2019/20 planning year capacity auction, officials say.

FERC rejected the proposal earlier this month, saying two aspects of the plan rendered it unreasonable. (See FERC Rejects MISO Plan for External Capacity Zones.) One of the rejected provisions would have allowed external resources bordering two local resource zones to choose in which zone they receive auction credits, while the other would have made holders of evergreen supply contracts eligible for excess auction revenues indefinitely.



Jacob Krouse | © RTO Insider

During an Aug. 8 Resource Adequacy Subcommittee meeting, MISO attorney Jacob Krouse noted the RTO asked FERC to view the proposal as an integrated package, making the rejection total.

"The commission, under the NRG paradigm, rejected the filing," Krouse said, referring to the July 2017 D.C. Circuit Court of Appeals ruling that FERC overstepped its authority when it suggested changes to a PJM proposal. MISO stakeholders warned last year that a rejection of the proposal was possible in light of the ruling. (See MISO Members: Court Rebuff May Reduce External Zone Chances.)

But RTO leadership appears undaunted by the rejection, planning to refile the proposal with two revisions Aug. 31.

"MISO believes that with the clear guidance we received from FERC ... we are going to be able to refile at the end of the month," Krouse said. "FERC did not note any concern with the vast majority of MISO's proposal — just those two parts."

Under proposed revisions, border resources that have participated in past Planning Resource Auctions will be assigned to the local resource zone in which they previously participated. New external resources that border two or more local resource zones will be assigned to the zone where the unit maintains the greatest electrical connection. MISO said it will measure electrical connectivity through line ratings using a contingency basis.

"MISO is proposing to assign resources to a single [local resource zone] instead of multiple zones," Krouse explained.

For evergreen supply contracts, MISO now proposes to allow units to collect excess auction revenues only until the end of the original term of the agreement or for two years, whichever is longer. Krouse said the RTO's filing will also include an option that removes the two-year extension, ending hedge eligibility as soon as the original contract expires. He said MISO intends to let FERC choose the provision it prefers.

Krouse asked for stakeholders to provide reactions to the changes by Aug. 17 and said the RASC will schedule a special Aug. 22 conference call to discuss feedback.

MISO Director of Resource Adequacy Coordination Laura Rauch said the change for border resources will apply only to a small subset of MISO resources.

Some stakeholders said the proposed treatment of evergreen contracts might violate the *Mobile-Sierra* doctrine, which holds that rates negotiated in a contract should be presumed to be just and reasonable.

"MISO is not changing the terms of the arrangement, so *Mobile-Sierra* would not apply," Krouse said, adding that the RTO is not encroaching on the terms of buying and selling power. Rather, such contracts would simply become ineligible for additional hedges from MISO after the original term of the agreement or the proposed two-year transitional period.

"We in no way intend to change or limit the terms of evergreen contracts," Rauch said. "These contracts were signed without consideration of the capacity construct."

Others commended the RTO for continuing to pursue external zone designation.

"I really appreciate MISO going in and being aggressive on this. ... We've been talking about this for half of a decade," said Coalition of Midwest Power Producers CEO Mark Volpe.

MISO IMM Voices Market Concerns, Commends Competitive 2017

Continued from page 13

"This year we will use most of the 120 days allotted by the Tariff," McFarlane said, adding that MISO has historically provided a written response within 90 days.

MISO Charts Market Improvements with Stakeholder Help

Meanwhile, MISO is continuing its Market Roadmap prioritization to determine what improvements it should undertake in 2019. Unofficial Market Roadmap rankings show that MISO and stakeholders agree that creating short-term capacity reserves is a pressing matter.

MISO melded its market improvement priorities with the Monitor's and stakeholders' rankings after a June and July voting period in which 67 stakeholders participated. (See MISO Stakeholders to Rank Market Improvement Ideas.) The preliminary results show the RTO should next year focus on creating an improved combined cycle generation model and developing a short-term capacity reserve product that can supply capacity within 30 minutes.

Three other projects earned medium priority: creating a multiday market forecast to guide generators' commitment decisions (See MISO Scales Back Multiday Market Proposal.); implementing a day-ahead market based on 15-minute intervals rather than hourly intervals as MISO replaces its market platform; and continuing work on resource availability and need exploration. (See MISO Moving to Combat Shifting Resource Availability.)

MISO market strategy adviser Lakisha Johnson said the RTO will finalize the prioritization of Market Roadmap projects through the end of the year.

MISO NEWS

MISO Energy Storage Group Seeks Expanded Role

By Amanda Durish Cook

MISO's Energy Storage Task Force is making a bid to broaden its role by seeking the authority to evaluate storage issues in addition to identifying them.

The group moved to revise its charter during a conference call last week, but any proposed changes are subject to approval by the Steering Committee at its next meeting.

The task force is currently limited to only identifying storage issues requiring MISO's attention. It then forwards its findings to the Steering Committee, which assigns the issues to larger stakeholder committees for decisions. (See *MISO Storage Task Force Defines Role, Seeks Plan*.)

But the group now wants the authority to evaluate "issues or topics that are unique to the integration or challenge the realization of benefits of energy storage," according to the revised charter. It would "also provide ongoing subject matter expertise to MISO entities regarding storage-related issues."

Task force Chair John Fernandes said the initial charter may have been too restrictive.

"That was a very unilateral, one-way mission statement," Fernandes said. "What we're saying here is that there's an opportunity for extended dialogue."

He said it can sometimes feel as if the group encounters "radio silence" after it identifies an issue taken up by a larger stakeholder committee.

Fernandes said the group will reconvene in September to discuss next steps if the Steering Committee refuses to approve the expanded charter.

Some stakeholders said the revised charter might open the door to two stakeholder groups having the same discussions about energy storage, violating the spirit of MISO's stakeholder process redesign three years ago that sought to reduce duplicative discussions across different RTO forums. (See *MISO Takes Stakeholders' Temperature on Redesign*.)

But Fernandes said there are broad storage subjects that warrant further task force discussions even if a specific issue may have been escalated to another MISO group. He cited hybrid storage facilities as an example, noting the interconnection of such plants is currently under discussion within the RTO, but the general business model requires more evaluation.

Fernandes also questioned the efficiency of stakeholder committees creating new task teams to discuss unique storage attributes when the task force could evaluate them.

He added that the task force plans to continue to stay out of developing commercial business models for storage, as recommended by the Steering Committee.

MISO Fills out Storage Capacity Plan

By Amanda Durish Cook

CARMEL, Ind. — MISO last week laid out a more detailed proposal for how it will determine the capacity accreditation of electric storage resources under FERC Order 841.

The RTO is proposing to determine electric storage resources' capacity based on two different measurements: the resource's power output capability and its energy storage capacity as measured by MISO's generator verification test capacity (GVTC).

Speaking at an Aug. 8 Resource Adequacy Subcommittee meeting, Senior Adviser of Capacity Market Administration Rick Kim said the rule will ensure both a megawatt and megawatt-hour measurement of a storage resource's capability.

Kim said for storage resources under 10 MW or that have fewer than 12 months of operational data, MISO will apply a 5% default equivalent forced outage rate in its unforced capacity calculation. Other storage resources will be assigned a forced outage rate based on their quarterly data inputs to MISO's generating availability data system (GADS). GADS reporting is required for storage resources 10 MW and above and optional for those under 10 MW.

Rick Kim | © *RTO Insider*

Because NERC hasn't yet addressed unit reporting for storage resources, Kim said resource operators should use the "miscellaneous" unit type option when reporting unit data.

"It's going to be another year before we see registration of energy storage resources," he added.

Kim also said storage resources connected to the transmission system will require either network resource interconnection service or firm transmission service with MISO to ensure capacity deliverability. If resources are connected at the distribution level, MISO will ensure deliverability with the distribution provider and transmission owner on a "case-by-case" basis, he said.

MISO has said that when storage resources are connected at the distribution level, market participants "must have sufficient metering or accounting for non-wholesale transactions to prevent double counting of energy."

The RTO in June said it would accommodate Order 841 by dividing storage bid parameters into four operating modes: discharging, charging, continuous operations and offline. Market participants will be left to choose a mode for individual dispatch intervals and will also be responsible for managing the state of charge of their storage units. (See *MISO Weighing Feedback to Storage Proposal*.)

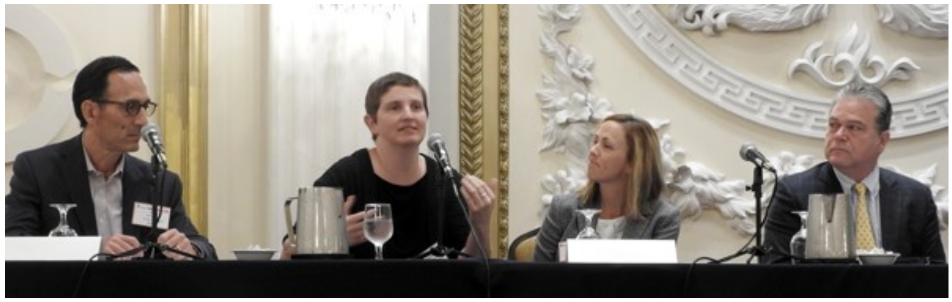
Storage resources will be able to set prices under MISO's extended LMP.

MISO and stakeholders will continue to discuss storage capacity accreditation at the September RASC meeting, with draft Tariff language targeted for October. November will be used to finalize the full Order 841 compliance filing before FERC's early December filing deadline.

Infocast New York Energy Market Summit

New York Energy Market Summit Tackles DERs

By Michael Kuser



Left to right: Stuart Nachmias, Con Ed; Melissa Kemp, Cypress Creek Renewables; Emilie Nelson, NYISO; and Paul A. DeCotis, West Monroe Partners. | *© RTO Insider*

NEW YORK — New York is charting its own course for integrating distributed energy resources into its grid, different from the path trod by states with already high rates of penetration, industry experts said last week.

"California and Hawaii had to be reactive to distributed generation, but New York is taking a more proactive approach in trying to incent greater penetration of clean energy resources," ScottMadden's **Chris Sturgill** said at the New York Energy Market Summit held Aug. 6-8.

Sturgill noted the New York Public Service Commission this spring approved new DER measures as part of the state's Reforming the Energy Vision initiative, which has enabled market participation for non-wires alternatives and the expansion of energy efficiency, demand response programs and demonstration projects. (See NYPSC OKs Con Ed EV Charging Program, REV Initiatives.)

"It's easier to bring DER onto the grid now, thanks in part to informed dialogue between the utilities and DER owners," Sturgill said.

"New York is pursuing aggressive policies to promote renewable energy, preserve competitive markets and resolve regulatory uncertainty," said Paul A. DeCotis, senior director of West Monroe Partners.

Data First

Conference panelists pointed out that the growth of DERs and electric vehicles is changing once predictable load patterns. Utilities need to ensure continued reliability, recognizing that regulators are not as close to the system as they are, they said.

"I would start with data," said Stuart Nachmias, Consolidated Edison vice president for energy policy and regulatory affairs. "We continue to support implementation of smart meters, and also the communications infrastructure to make them usable … but price signals are important to get generation closer to load … which is how New England evolved their locational pricing."

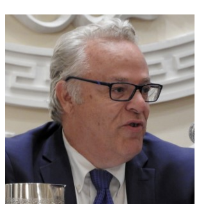
Con Ed subsidiary Orange and Rockland Utilities, which serves customers in southeastern New York and northern New Jersey, has "seen a lot of solar proposals, which is not where the demand is," Nachmias said.

Melissa Kemp, Northeast policy director for Cypress Creek Renewables, said New York must have a larger conversation about how to compensate solar projects.

"Initial costs may avoid later costs, such as avoided transmission spending, and a project may have positive health benefits, and those positive attributes should be accounted for, if not compensated," Kemp said.

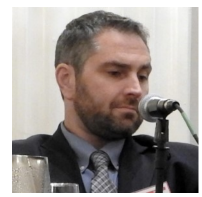
She also pointed to the importance of maintaining the low-income customer perspective and protecting against unnecessary rate increases. She added that those customers would also bear any extraordinary costs in the future, which could be avoided by increased spending now.

New Business Model?

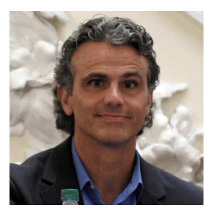


Ross Kiddie, director at West Monroe Partners, noted that New York utilities submitted their second Distributed System Implementation Plans (DSIP) to the PSC a week earlier (Case No. 14-M-0101) and asked what are the must-have technologies to deal with DERs.

If people had controllable toasters, the utility or aggregator could preset a million of them and stagger their times to avoid spikes, said **James Pigeon**, NYISO manager of distributed resources integration.



"As we move forward, and the aggregators have the ability to control these assets, things will change," Pigeon said. "The NYISO is not looking to change the business model and apply unique programs to every node on the grid. … We want to apply one model and have those resources respond to NYISO direction, whether for demand management or price signal."



Damian Sciano, Con Ed director of distribution planning, said the electric system is moving from dozens of large generators to thousands of small-scale residential units, which could go into the millions when every customer's appliances are connected to the grid.

"NYISO looks at New York City as just Zone J, but to us it's a bunch of distribution lines that have thermal limits and voltage concerns," Sciano said. "So when an aggregator puts together a bid for say 10 MW, it may completely satisfy what the NYISO is looking for, but it may be 10 MW on a part of the grid where we can only tolerate 2 MW at any given point."

It goes back to the DER management system, even if someone else is aggregating something for the utility, he said. "We want

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Infocast New York Energy Market Summit

New York Energy Market Summit Tackles DERs

Continued from page 16

to know exactly what's being generated, very much preferably real-time, and understand how it's affecting our system," Sciano said.

Emilie Nelson, NYISO vice president for market operations, said she is focused on administering capacity and pricing at the wholesale level.

"If you rewind 15 years, the expectation for natural gas prices was not what they are today, so expectations can shift; reality can shift. A functioning market allows for third parties to bring in new solutions," Nelson said.

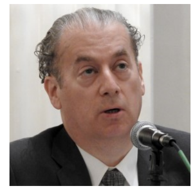
| © RTO Insider

Storage Issues

Sturgill asked how the ISO will consider proposals for energy storage resources in the wholesale market, particularly for those that are dual participation or trying to collect multiple pieces of the value stack. (See NY Releases 'Roadmap' for 1,500-MW Storage Goal.)

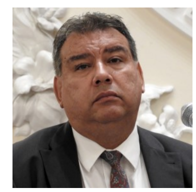
New York City is dedicated to working with utilities and others to value new DER technologies properly, including storage, said **Susanne DesRoches**, Mayor Bill de Blasio's deputy director for infrastructure and energy.

"We see storage being able to support transmission and support the local network ... for the complex picture in New York City, which is a bunch of islands with a unique power supply," DesRoches said. "Storage should be valued properly for the attributes it provides for the system, and also we need clear permitting."



Storage needs to be treated fairly on the system, said **Peter Mandelstam**, executive director for GRID Alternatives Tri-State, the largest solar energy nonprofit in the U.S.

"Having been involved in a lot of regulatory battles over the decades, both at the state and federal level, the most important thing is to get the rules right," Mandelstam said. "Storage is now here, is now integral to the complete decarbonization of our electric system ... the digital age now allows for the metering."



Illinois Commerce Commissioner **John Rosales**, also vice chair for electricity at the National Association of Regulatory Utility Commissioners, said smart metering "is the catalyst" to put together a microgrid or adopt new technologies such as energy storage.

As a regulator, "you'll never make everyone happy; there will be winners and losers, and they'll be so unhappy that they will sue you," Rosales said. "However, it's important to remember that not making a decision is a decision."

Infocast New York Energy Market Summit

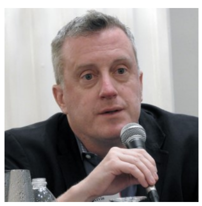
Overheard

NEW YORK — NYISO CEO Brad Jones likely summed up the sentiments of the dozens of industry experts attending Infocast's New York Energy Market Summit last week to learn more about the state's rapidly evolving grid and changing policy landscape.

"All of us seem so thankful to be in this industry at this time," Jones said. "There's so much change going on, so much opportunity to do new things and create new things."

Here's more of what we heard at the summit.

Tx Development 'Eats Its Own Young'



Kevin Sheen, vice president of business development at Terra-Gen, said New York began falling behind other states in renewable development despite having started a 10-year renewable energy credit (REC) program in 2004 that managed to incent about 1,400 MW of wind over the past decade or so.

Realizing it needed to do more, the state last year began offering 20-year REC contracts, Sheen noted. He said that the state's commitment to improve transmission signals to developers that New York is worthy of their investment and time. The ISO's Congestion Assessment and Resource Integration Study process identifies the top congestion elements on the system and indicates where developers ought to be thinking in terms of building additional transmission. (See *NYISO Study Identifies Key Areas of Tx Congestion*.)

"Delays are part of development — they happen in every market — but I think New York has done the best they can to try to address that," Sheen said.

Transmission developers cited permitting and interconnection costs as the two biggest risks for new project development.

"We recently saw Deepwater Wind narrowly get through the East Hampton town board process by a 3-2 vote, so five individuals held the fate of that 90-MW cable" connecting the offshore project to land, Anbaric Development Partners project

manager **Bryan Sanderson** said.

Bringing 2,400 MW into NYISO Zones J and K is going to be hard because the ISO's study process takes three to five years, Sanderson said, leaving companies to bid today on costs they will not know until 2022.

"Imagine New York procuring its first offshore wind farm and the interconnection costs come in $500 million more than projected," he said. "That would be a huge embarrassment. Just ask Massachusetts about their Northern Pass experience.

"One problem with transmission development is that it eats its own young, so you solve the problem like congestion and the price arbitrage disappears," Sanderson continued. "How do you pay for your line when your mere existence eliminates your profit stream?"

John Douglas, CEO of transmission developer oneGRID, noted there's been talk of developing a national backbone grid to optimize renewables, but no one has resolved the problem of who will pay for it and how all the RTOs would interact.

"It's unfortunate, because we're going to end up with all these regional, Band-Aid optimizations when there could be something national," Douglas said.

Public Policy Challenge

Jones addressed the conflict between state policies and RTO market principles, pointing out that both ISO-NE and PJM went to FERC with solutions to what they saw as state interventions that could undermine their wholesale markets.

"When New England brought CASPR [Competitive Auctions with Sponsored Policy Resources] to the commission, they said, 'We want to address it in this way,' essentially to change the capacity market structure, which would arguably eliminate the impact of state subsidies on new resources," Jones said.

"The FERC agreed with them, but in a decision which I never knew was possible. They approved 3-2," Jones said. "Clearly the FERC was torn; they struggled with that decision." (See *Split FERC Approves ISO-NE CASPR Plan*.)

Jones said the commission saw ISO-NE's solution as being different from PJM's rejected solution in that the former was dealing only with new assets that were being subsidized, while the latter was dealing with both new and existing assets, primarily nuclear and coal units.

"New York looks very similar to PJM, with assets that have been retained, plus new assets, but FERC has not decided to take any action on New York," Jones said. "I think the commission is waiting to see where the NYISO gets on its work to price carbon directly into the wholesale market." (See *Stakeholders Annoyed by NYISO Carbon Price Draft*.)

Off the Grid

Douglas said he realized how most large industrial customers are looking for change when he heard that a survey by one of the nation's largest utilities found that its top 15 customers all want to get off the grid.

"Imagine you're an integrated, investor-owned utility and your top customers are all saying they don't want to have anything to do with you," Douglas said.

oneGRID is planning the 1,000-MW HVDC Empire Connector project to move energy from upstate into New York City via the Gowanus Substation in Brooklyn. The project is now in the second phase of its solicitation, aggregating wind, solar and biomass supply offers to sell into the city.

Contracted merchant power "is a forgotten pathway to transmission development," and customers in New York want it, Douglas said.

"We found out how important physical delivery is to customers in New York City for both reliability, and probably more importantly, for resilience," Douglas said. "HVDC is so controllable that it actually counts as in-city generation, so it's a tremendous advantage."

While renewable energy resources are known for changing the direction of power flow on the grid as smaller generators along the line feed their excess electricity back onto the grid, New York City has so far been unaffected by that phenomenon, said Damian Sciano, Consolidated Edison director of distributed resource integration.

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Infocast New York Energy Market Summit

Overheard

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"We're in a dense urban area … so even when someone puts a fairly large solar installation in, or CHP [combined heat and power] — those are the two big things we see in our service territory — it's pretty much consumed very close to where it's generated," Sciano said. "We don't typically have backfeed on the substations."

Valuing Offshore Wind

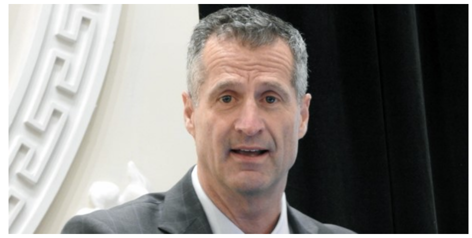
Lawrence Berkeley National Laboratory research scientist **Andrew Mills** said a team at the lab compared the levelized cost of energy estimates with value estimates and found that the most attractive U.S. sites for offshore wind are located off New England, while the least attractive are far offshore of Florida and Georgia, where the water is deeper and the wind speeds are lower.

Wind energy off the southeast coast is worth about $160/MWh less than the best sites up north, he said.

"We were very interested in questions about the seasonal and diurnal profiles of offshore wind and how much that might be driving differences in the value across these sites," Mills said. "If you were to just have a flat block of power, which is constant across all hours, we wouldn't be far off in the estimates we came up with … within 5% or so."

Differences in average energy and REC prices primarily drive locational variations, not differences in diurnal and seasonal wind generation profiles, he said. The market value of offshore wind was lowest in the most recent year evaluated, 2016, falling roughly 50% from 2007.

The marginal total market value of offshore wind — considering energy, capacity and RECs — varies significantly by project location and is highest for sites off of New York, Connecticut, Rhode Island and Massachusetts. The median, 2007-2016 market value is highest in ISO-NE (around



NYISO CEO Brad Jones | © *RTO Insider*

$110/MWh), in part because of higher REC prices. The energy and capacity value is higher for NYISO, particularly Long Island.

If you look south, the median value is "significantly lower, down in the $55/MW range in the non-ISO region south of PJM," Mills said.

The capacity value can be up to 50% different from that calculated based on a flat block of power, but capacity value is only a small component of overall value, Mills said. The capacity credit of offshore wind in the NYISO and ISO-NE markets is significantly higher in winter than in summer, with offshore wind in these regions benefiting from having capacity credit assessed in both seasons.

PJM NEWS

OC Briefs

What Does it All Mean?

VALLEY FORGE, Pa. — PJM is hoping to simplify its communication of items that require stakeholder action through a new "stakeholder impact slide" in appropriate presentations, PJM's Rebecca Carroll told members at last week's Operating Committee meeting.

The slide will identify what action is needed, the deadline and which stakeholders it impacts.

"It will spell out very clearly what the action is that is required for the stakeholder," Carroll said.

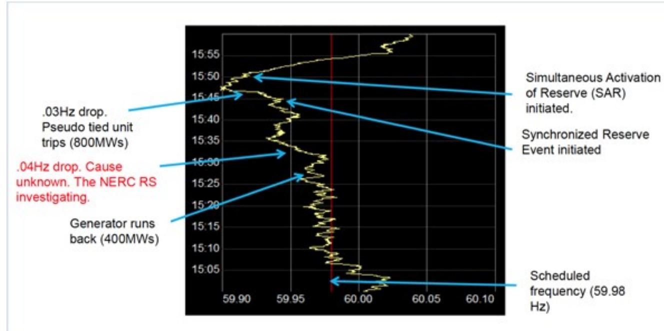
The concept will be piloted in the OC and the Tech Change Forum before it's rolled out elsewhere, she said.

Low Frequency

Grid operators handled an unusual number and variety of issues in July, staff explained.

Chief among them was a low-frequency event on July 10 between 3 and 4 p.m. Operators had been targeting a frequency of 59.98 Hz to account for a "time error correction," but it fell to 59.903 Hz by 3:45 p.m. The event occurred in two frequency drops, and staff are puzzled over what caused the first one.

In the five minutes after 3:30 p.m., the frequency gradually dropped by 0.04 Hz, and PJM staff are working with NERC's Resource Subcommittee to determine why. PJM's Chris Pilong said the analysis is "not to point fingers" and that RTO tools intended to determine the cause of such issues "right now … aren't pointing to anything."



A timeline of the July 10 low-frequency event with brief analysis of several events. | *PJM*

"It's going to be outside the PJM system," he said. "We're thinking there may be some data errors in there somewhere."

A second 0.03-Hz drop that began around 3:40 p.m. was caused by an 800-MW pseudo-tied unit tripping, Pilong said. Just before the drop, PJM initiated a synchronized reserve event, which deployed all the RTO's synchronized reserves. PJM's pseudo-tie error was roughly 900 MW under its target leading into the reserve event, and it dropped further down to 1,800 MW at the frequency's lowest point.

PJM called a "simultaneous activation of reserve" (SAR) with the Northeast Power Coordinating Council at 3:50 p.m., about five minutes after the second frequency drop. The frequency rebounded to above its target level within five minutes.

Staff said the event isn't normal but does happen every three years in the Eastern Interconnection. While this was the lowest they'd seen, it would have had to fall another 0.1 Hz for operators to call for a load action.

The puzzle for staff is what caused the initial drop, which drifted down rather than dropping immediately in a way indicative of a unit tripping.

"We drifted low. It wasn't a step function low," PJM's Glen Boyle said.

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Spinning Events

Grid operators also dealt with "obviously a higher volume of spinning events" than usual during July, Pilong said. The cause was multiple generators tripping, he said, but initial analysis indicates they were all unrelated. He said staff would analyze whether the system is experiencing more generators tripping or if there are any other takeaways.

"This could have just been a fluke month, or it could be a trend of something more," Pilong said.

Load Shed

Staff confirmed that the load shed ordered July 18 was dissimilar to the load shed that occurred just months earlier in the same transmission zone.

The July 18 event occurred in the Lonesome Pine area on the border of Virginia and West Virginia after tripped equipment caused low voltage in the area. The events in American Electric Power's zone were the first since PJM implemented Capacity Performance and its financial penalties and bonuses for generator performance during reliability events such as load sheds, though neither event triggered those calculations. (See *2nd Load Shed of PJM's CP Era Follows Closely on 1st*.)

Staff said the events differed in that the Lonesome Pine event was in response to actual system conditions while the previous Twin Branch event was based on concerns identified through simulations.

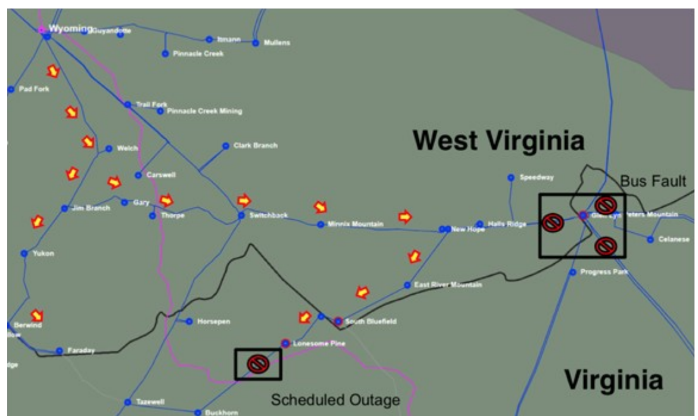
"That was a little more complex," Pilong said. "This one was a little more straightforward."

Citigroup's Barry Trayers asked if PJM would develop additional CP event categories for situations like this with no financial repercussions. Staff confirmed the Lonesome Pine event did not create a balancing ratio since no generators were involved.

User Interface Fuel Security Changes

PJM's Brian Fitzpatrick announced "voluntary" gas usage data requests, but stakeholders were skeptical whether the requests would be implemented that way.

Fitzpatrick said PJM is asking gas-fired generators to report through its Markets Gateway online interface all gas nominations made to the appropriate city gate. PJM is attempting to correlate the amount of gas requested at a location with its ongoing study of gas pipeline contingency plans.



A diagram of the area around the July 18 load shed. | *PJM*

"We're not looking for what the [local distribution company] is nominating," Fitzpatrick explained. "We're looking for what the generators are nominating to the LDC."

PJM's Dave Souder confirmed that "it's not a mandatory field" that must be completed for a generator's energy market bid to be accepted, "but it is information we're asking for" and staff will be contacting those who don't comply to help them become "comfortable" with providing the information.

"It's voluntary to the extent that if you don't enter it, we won't reject your bid … but this is information that we want so that we can move this gas contingency process forward," Souder said.

— Rory D. Sweeney

PJM Seeks to Delay 2019 Capacity Auction to August

PJM last week asked FERC to delay next year's Base Residual Auction to Aug. 14 to provide the RTO more time to respond to the commission's June 29 order requiring changes to capacity market rules.

The commission ordered PJM to expand its minimum offer price rule (MOPR), which now covers only new gas-fired units, to all new and existing capacity receiving out-of-market payments. The commission's ruling, which rejected PJM's April "jump ball" capacity filing (ER18-1314) and partially granted a 2016 complaint led by Calpine (EL16-49), initiated a Section 206 proceeding in a new docket (EL18-178). (See *FERC Orders PJM Capacity Market Revamp*.)

PJM requested the delay in an Aug. 9 filing supporting the Organization of PJM States Inc.'s (OPSI) motion to extend to Oct. 11 the deadline for filing testimony, evidence or arguments in response to the FERC order (EL16-49, *et al.*).

The RTO asked the commission to issue an initial order directing a compliance filing by Jan. 15 and a final order on compliance by March 15. "This proposed schedule will provide PJM and capacity market sellers with approximately five months to undertake the Tariff imposed obligations in advance of the delayed BRA," PJM said.

PJM, OPSI and more than a dozen other parties also have requested rehearing of the commission's ruling, including industrial customers, the American Public Power Association, Exelon, Old Dominion Electric Cooperative, Dominion Energy, FirstEnergy Services, and regulators from Illinois, New Jersey and Maryland.

— Rich Heidorn Jr.

PJM News

PJM Reeling from Major FTR Default

By Rory D. Sweeney

VALLEY FORGE, Pa. — PJM staff are still working on how to respond to GreenHat Energy's default in the financial transmission rights market, CFO Suzanne Daugherty told stakeholders at last week's Market Implementation Committee meeting.

Daugherty announced at the June meeting of the Markets and Reliability Committee that GreenHat was likely to default on payments for a sizable FTR portfolio that was proving unprofitable. After the company defaulted, PJM staff realized that their current rules for attempting to mitigate the financial burden to members might instead exacerbate the situation and requested a waiver from FERC to find a more effective solution (ER18-2068).

The Tariff requires PJM to liquidate the FTRs of a defaulted member by offering for sale "all" current planning period FTR positions in the next monthly balance of planning period FTR auction "at an offer price designed to maximize the likelihood of liquidation of those positions."

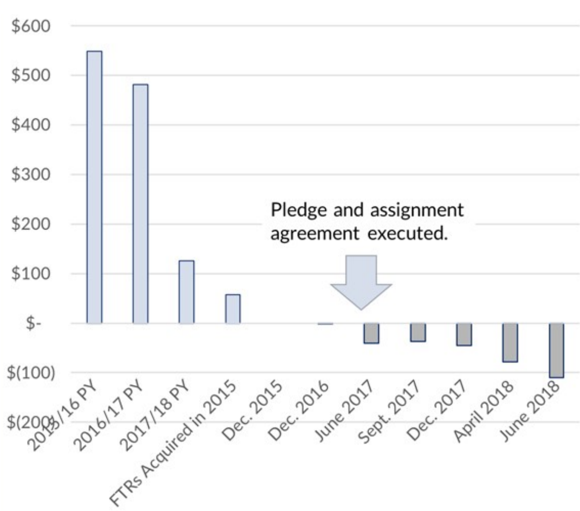
PJM said a waiver is required "given the market impact by the liquidation of GreenHat's large FTR portfolio and observed low levels of market liquidity more than one month forward (i.e., non-prompt months)." Staff found that the bids offered to take the portfolio's positions would have been approximately four times the pre-default auction clearing prices on the affected paths. Instead of being forced to liquidate the entire portfolio at once and potentially suppress the holdings' return in an illiquid market, PJM asked FERC on July 26 to allow it to not liquidate each FTR position until the month it becomes due in the market. FERC has not yet responded. (See " Default Details," *PJM MRC/MC Briefs: July 26, 2018*.)

At the same time, PJM also requested a waiver of its requirement to return collateral posted by Orange Avenue, another FTR market participant that is affiliated with GreenHat (ER18-1972). Orange has challenged that request, but PJM argued that it may become necessary to sue Andrew Kittell, who oversees both firms, and that Orange's collateral would be included among Kittell's assets.

When GreenHat acquired most of its positions starting in 2015 long-term FTR auctions, both historical congestion and the FTR auction clearing prices indicated that the portfolio would be profitable, so it had a low credit requirement. However, by April 2017, PJM staff realized the portfolio, consisting primarily of prevailing-flow FTRs, were on paths where transmission upgrades were expected to reduce future congestion.

According to PJM, GreenHat's portfolio was estimated at $57 million based on the auction clearing prices when the positions were taken. In the 2015-16 planning year, the same portfolio would have netted $548 million. It dropped slightly in the next planning year to $481 million. However, the following year the value dropped precipitously to $126 million and continued falling in subsequent auctions. By June 2018's auction, the portfolio would have lost $110 million.

After realizing GreenHat's exposure, staff approached Kittell, who offered to mitigate some of the potential risk by signing over what he told PJM were the rights to receive $62 million in proceeds from several bilateral FTR contracts.



Estimated value of GreenHat FTR portfolio ($ millions) | *PJM*

PJM accepted the agreement in June 2017 and opened a bank account for the expected proceeds, but the other company in the contract, whose name was redacted from the public filings in the docket, says it paid what it owed to GreenHat well before Kittell signed the agreement with PJM. The RTO wants FERC to allow it to keep the collateral from Orange while it investigates "whether Mr. Kittell and GreenHat fraudulently induced PJM to enter into the pledge agreement." FERC hasn't responded to that request yet either. Kittell did not respond to a request for comment.

His attorney, David Gerger, also declined to comment but pointed to Orange's July 27 protest, in which it told PJM it "was not making any representations or warranties about the value of the additional collateral … and that PJM must make its own valuation."

Orange said "PJM was uniquely poised to [establish the value of the collateral] because the [$62 million] number came from applying the PJM Tariff to amounts entered into PJM's FTRCenter System."

In the wake of the GreenHat default, PJM received stakeholder endorsement to enhance its credit policy for FTR traders. The new rules, to be implemented on Sept. 3, will institute a 10-cent/MWh minimum monthly credit requirement for FTR bids submitted in auctions and cleared positions held in FTR portfolios. (See "Credit Requirements," *PJM Market Implementation Committee Briefs: July 11, 2018*.)

However, Daugherty confirmed at the MIC meeting that GreenHat remained compliant with the credit requirements existing at the time until it failed to post a collateral call in April. Stakeholders grilled her on why PJM hadn't previously attempted any regulatory action or policy changes if it knew about the concern nearly a year and a half ago.

"There was nothing specific in the credit policy that would have allowed PJM to make a collateral call" sooner, she said, noting that the agreement with Kittell was signed in June 2017.

Additionally, staff said that FERC lacked a quorum of commissioners at the time and that stakeholders had not yet agreed on revisions on how to analyze predicted congestion. Daugherty said staff made a "good faith effort" to bring GreenHat and

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PJM NEWS

MIC Briefs

Balancing Ratio

VALLEY FORGE, Pa. — Stakeholders at last week's Market Implementation Committee meeting overwhelmingly endorsed PJM's proposal for revising how it calculates balancing ratios while also rejecting several competing proposals.

PJM's proposal received 0.88 in favor, surpassing a 0.5 threshold in the sector-weighted vote. Stakeholders also preferred it to the status quo, voting 0.69 in favor of the new proposal.

The proposal, known as Package A, would calculate the balancing ratio used in the default market seller offer cap (MSOC) and nonperformance charge rate (PPR) formulas by averaging the balancing ratios from the three delivery years that immediately preceded the capacity auction. For years that don't have at least 30 hours of performance assessment intervals (PAIs), the actual number of PAIs would be supplemented with estimated balancing ratios calculated during the intervals of the highest RTO peak loads that do not overlap a PAI. PAIs are five minutes apiece.

Some stakeholders like the proposal because it is straightforward and maintains the same number of PAIs used in either the MSOC or the PPR. However, others argue the calculation overestimates the likely number of PAIs, which leads to an artificially high MSOC. Such conditions led Independent Market Monitor Joe Bowring to conclude last week that the clearing prices in May's Base Residual Auction were higher than they should have been. (See related story, *IMM: PJM 2018 Capacity Auction was 'Not Competitive'*.)

"This all turns on your belief that 30 hours is a reasonable number [for PAIs]. I don't believe that. … I would say it's pretty clearly not a reasonable number," Bowring said.

"We don't have any technology that can solve that problem [of accurately predicting the number of PAIs], so we're left with what is a reasonable number to put in there," PJM's Adam Keech said.

"The 30 hours is definitely an issue for the consumer advocate offices I've talked to," said Greg Poulos, executive director of the Consumer Advocates of the PJM States.

Stakeholders have been debating the issue for months. (See "Balancing Ratio," *PJM Market Implementation Committee Briefs: July 11, 2018*.)

PJM's Pat Bruno announced that staff planned to abandon a second proposal, Package B, unless a stakeholder offered to sponsor it. Dave Mabry, representing the PJM Industrial Customer Coalition, agreed to do so. The proposal would calculate the balancing ratio in the same manner as Package A but would also estimate an expected number of PAIs for the delivery year using data from the prior three years. That estimate would be inserted into the MSOC and PPR formulas.

Each formula would include a floor of PAIs, but they would differ: five hours for the MSOC and 15 hours for the PPR. That difference concerns stakeholders, who argue the numbers need to be the same for the formulas to maintain their mathematical relationship.

"We don't share PJM's thoughts that they

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PJM Reeling from Major FTR Default

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Kittell to heel.

Several stakeholders pushed PJM to provide even a rough estimate of the expected losses. One, Vitol's Joe Wadsworth, said he used recent market results to determine that it could be upward of $145 million.

"It is getting worse," he said.

If accurate, the result would be almost triple the $52 million credit default by Tower Research Capital's Power Edge hedge fund in 2007, which also triggered credit policy revisions. (See *PJM Credit Adder Fails upon Heightened Review*.)

Daugherty resisted the requests, saying that it would be impossible to accurately predict.

"We will not know the dollars until they play out or they are liquidated because we may have to pay to liquidate them," Daugherty said.

"There's urgency here. We can't just let this ride on the market," Wadsworth said. He said engaging with GreenHat once the risk was identified was "clearly the right thing to do," but he asked why the company was allowed to continue participating in the auctions.

"These numbers are kind of scary. We're trying to find out … how big this is going to be," Old Dominion Electric Cooperative's Adrien Ford said. "I'd appreciate some sort of take on it so I can go back to the home office and say 'roughly we think it's about this size.'"

"I don't think you should expect that PJM's going to project a number," Daugherty said.

Stakeholders also debated the best strategy for how to liquidate the portfolio if FERC approves PJM's waiver request. Some, including Wadsworth, called for immediate action, as auction results have shown a continuing downward trend. Others, including Direct Energy's Marji Philips, argued it might be better to wait to see if something materializes that's better than the current guaranteed loss.

"Do you liquidate today and have a fixed number, or do you want to not liquidate today, and the number might come in lower," she said.

PJM is working with its members to agree upon a strategy at the August MRC meeting and targeting a final approval vote at the September MRC meeting.

According to PJM's rules, all members will be on the hook for at least some of the losses. Of the final amount, 10% will be allocated on a per capita basis to the 992 members, including affiliates, as of June 21. The per capita assessments are capped at $10,000 per year, though Daugherty confirmed the rule's intention was for the cap to count per default event and that the language may need to be clarified.

The remaining losses will be allocated according to each member's gross PJM activity over the three months preceding

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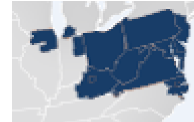
PJM NEWS



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| © RTO Insider

have some problems at FERC with the" formulas, Mabry said in sponsoring the proposal. American Municipal Power's Steve Lieberman seconded it, and it received 0.09 in favor.

Additional proposals from Exelon and Calpine differed with PJM on the PAI calculations for the formulas. Calpine's would floor both at 10 hours and calculate a number based on the past 10 years of data. Exelon's would use a probabilistic model to look forward. Both would keep constant the number of PAIs used in the two formulas.

"We think it's illogical to have different assumptions for those calculations," Exelon's Jason Barker said.

"The heart of our proposal was to get the expected amount of performance assessment [intervals] to match. It didn't make sense to us [to have them not match], and I don't think it would make sense to FERC," Calpine's David "Scarp" Scarpignato said.

Scarp withdrew his proposal in favor of PJM's Package A. Exelon's received 0.36 in favor.

"I am more in favor of fixing the immediate problem of the" balancing ratio, Scarp said.

"You can't fix [the balancing ratio] without addressing the problem on a consistent basis," Bowring said.

A proposal from the Monitor, which mirrored Package B except that it had floors of just five hours for either formula, received 0.02 in favor.

Quadrennial Review of VRR Curve

Stakeholders endorsed a proposal from Scarp on revisions for PJM's quadrennial review of the variable resource requirement (VRR) curve in its Reliability Pricing Model capacity market construct. Several other proposals, including one endorsed by PJM, were rejected by stakeholders.

Despite the result, all four proposals will be up for consideration at the August meeting of the Markets and Reliability Committee meeting. Stakeholders had made that request long before the vote in an attempt to overcome the influence of companies with multiple affiliates, which can each vote separately at lower committees.

Scarp's proposal largely mirrored PJM's, except that it maintains the current combustion turbine configuration as the curve's reference technology; the RTO had planned to change it to a newer model. It also maintained the curve's current calculation, while PJM and the other two proposals would have shifted it 1% left. The shift was part of revisions recommended by the Brattle Group, who were hired by PJM

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PJM Reeling from Major FTR Default

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the default. The RTO said the total activity for the period was $24 billion.

So far, PJM has sent, or plans to send, bills for $42.5 million, about 18% of GreenHat's portfolio.

Daugherty confirmed "there is no other situation like [GreenHat's exposure] related to credit requirements." She said PJM is working with external consultants from trading exchanges, clearing houses, other consultants and its Independent Market Monitor "to review factors that can affect future congestion levels and [perform a] gap analysis against how FTR credit requirements would address those factors." The talks are excluding members to avoid potential conflicts of interest.

DC Energy's Bruce Bleiweis said the incident was not a failure of the FTR market or structure but "clearly a significant failure of the credit policy."

However, he expressed concern that PJM's presentation indicated staff might agree with the IMM's position that the benefits of long-term FTRs are outweighed by their risks.

In June, stakeholders endorsed changes to the long-term FTR auction construct to prohibit participants from obtaining the rights to congestion on transmission paths before the owners of the underlying auction revenue rights. The Monitor has said the revisions are improvements but don't go far enough. (See "Long-term FTRs Undercut Annual FTRs," *PJM Market Implementation Committee Briefs: June 6, 2018*.)

Kittell worked as an energy trader for JPMorgan Venture Energy Corp. when FERC fined the company $285 million and ordered it to disgorge $125 million for "manipulative bidding strategies" from September 2010 through November 2012. Kittell and two other employees named by the commission were not charged.

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to analyze the curve. (See "VRR Curve Update," *PJM Market Implementation Committee Briefs: July 11, 2018*.)

PJM's proposal received 0.39 in favor.

David "Scarp" Scarpignato | © *RTO Insider*

A proposal from the Monitor agreed with PJM on updating the reference technology, but it differed on several other factors. That proposal received 0.1 in favor.

A proposal from the D.C. Office of the People's Counsel sought to use a combined cycle unit for the reference technology and otherwise largely mirrored the Monitor's proposal. It received 0.1 in favor, as well.

Fuel Cost Policy

John Rohrbach of ACES, representing the Southern Maryland Electric Cooperative, presented a proposed problem statement and issue charge to review the first year's performance of the new fuel-cost policy rules and determine if any improvements can be made.

The proposal was also endorsed by Old Dominion Electric Cooperative and Panda Power Funds. The group hopes to have any potential revisions to the current policy identified by April 19 to target a June filing at FERC. Any potential alternatives to the current policy that are identified would need to be ready for consideration by the fall to target a FERC filing in the fourth quarter.

TCPF

PJM and its Monitor have developed a joint proposal to revise how the transmission constraint penalty factor is utilized. PJM's Angelo Marcino explained that the current process uses "constraint relaxation" so that the penalty factor doesn't set shadow prices. This "masks" transmission shortages in the market. The proposal would remove constraint relaxation and allow the $2,000/MWh penalty factor to set prices as appropriate.

The proposal received so little reaction that PJM suggested canceling the next meeting of the group overseeing the issue, which stakeholders approved.

After the meeting, PJM posted online an analysis from the Monitor on the potential impact of the proposed revisions. The Monitor found that in 2017 the revisions would have increased the balancing market in the aggregate by $10 million.

— Rory D. Sweeney

IMM: PJM 2018 Capacity Auction was 'Not Competitive'

Continued from page 1

nues from the auction would have been only $6.57 billion had all identified non-competitive offers been capped at their net avoidable cost rate (ACR). The analysis said offers exceeding net ACR, while permitted by current rules, amounted to "economic withholding" and boosted total auction revenue by 41.5% to $9.3 billion.

Capping at net ACR would have reduced the RTO clearing price from $140/MW-day to $90.47/MW-day. "All binding constraints would have remained the same except that the ComEd import constraint would not have been binding and the DEOK import constraint would have been binding," the analysis said.

It singled out nuclear units, saying more nuclear capacity was offered at higher sell offer prices and fewer nuclear megawatts cleared than in 2017.

Although the IMM has regularly cited structural market power in the capacity market, 2018 was the first time that mitigation efforts failed and market prices were inflated, said Joe Bowring, president of Monitoring Analytics, which serves as PJM's independent Market Monitoring Unit (MMU).

"I think it's significant," Bowring said in an interview. "It's the result of the fact that the offer cap in the rules is mis-specified and needs to be fixed. We've been making that point for a while. But that issue resulted in an impact on this auction."

PJM issued a statement Friday disagreeing with the Monitor's conclusions.

"While PJM respects the Market Monitor's opinion, the facts regarding the 2021/2022 Base Residual Auction are clear. The auction was conducted in accordance with all Tariff-specified requirements and rules, including those rules related to the application of offer caps, and the offers were in concurrence with those rules. The Market Monitor expresses an opinion of what the offer cap should be; the proper forum for such concerns about competitiveness of offers is the Federal Energy Regulatory Commission."

Grades

For the 2018 BRA, the Monitor gave "not competitive" grades to the aggregate and local market structures, as well as market performance and participant behavior. Market design was judged "mixed." The Monitor gave the 2017 BRA the same grades for market design and structures but rated both participant behavior and market performance as competitive.

The IMM said this year's auction failed the competitive test because of the way PJM sets the offer cap under Capacity Performance rules.

"Some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of net CONE [cost of new entry] times B [balancing ratio]. But net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's Capacity Performance filing, is net ACR. That

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is the way in which most market participants offered in this and prior Capacity Performance auctions."

Because net CONE times B exceeds the competitive level in the absence of performance assessment hours (PAHs) — periods requiring urgent actions, such as the dispatch of emergency or pre-emergency demand response — it should be re-evaluated for each BRA, the report said.

Repeating a recommendation it first made in 2017, the Monitor said PJM should develop forward-looking estimates for both B and the expected number of PAHs used in calculating rates for nonperformance charges.

The Monitor said CP rules, which increased penalties for nonperformance, "have significantly improved the capacity market and addressed many of the issues" it previously identified.

But it also said the CP Tariff language is overly rigid. "If the Tariff had defined the offer cap consistent with PJM's filing in the Capacity Performance matter, the offer cap would have been net ACR rather than net CONE times B," the report said.

"The bottom line is net CONE times B is way too high, especially when the performance assessment hours are less than 30," Bowring said.

Of the 1,132 generation resources that submitted CP offers for delivery year 2021/22, 953 (84%) used the net CONE times B offer cap, while 129 (11%) were price takers.

Only eight generation resources (0.7%) requested the Monitor calculate unit-specific ACR-based offer caps. "The fact that so few resources requested unit-specific offer caps is further evidence that the net CONE times B offer cap exceeds competitive offers," the Monitor said.

Delivery Area	Actual Capacity Price ($/MW-day)	Capacity Prices Capped at Net ACR ($/MW-day)	% Change
RTO	$140.00	$90.47	-35%
ATSI	$171.33	$169.65	-1%
Eastern MAAC	$165.73	$155.93	-6%
PSE&G	$204.29	$204.29	0%
BGE	$200.30	$162.74	-19%
ComEd	$195.55	$90.47	-54%
DEOK	$140.00	$128.47	-8%

| PJM, Monitoring Analytics

PJM Disputes

PJM noted that market sellers must declare whether they will use net ACR or the net CONE times B offer cap 120 days before the auction.

"During the weeks where actual offers are submitted and the auction is cleared, the IMM has full visibility into all data relevant to the auction, including resource offers. If the IMM believed that economic withholding was taking place based on submitted offers and preliminary auction clearing results, the IMM could have consulted with the asset owner during that time period," PJM said.

"If the IMM believes that economic withholding took place, the proper course of action is for the IMM to refer the market seller responsible for such offers to FERC for further investigation. If the IMM believes that the current rules regarding the default offer cap allow for economic withholding, the IMM, like any other stakeholder, can bring forward a problem statement and issue charge to be discussed by the PJM stakeholder body."

Bowring noted that the issue of the balancing ratio is before the Market Implementation Committee. (See related story, "Balancing Ratio," *PJM Market Implementation Committee Briefs: Aug. 8, 2018*.)

PJM also questioned the IMM's simulation results for nuclear units offering at their ACR. "They are based upon hypothetical offers that could have been submitted on the basis of the IMM's anticipation of potential performance assessment hours, as well as the IMM's determination of the appropriate value of ACR to use for certain resources as opposed to their actual going-forward costs," PJM said. "Given these errors in the assumptions, the simulations bear no direct relevance to any hypothetical auction outcome had different offer-capping rules been in place for this auction."

PJM spokesman Jeff Shields said the RTO does not agree that there is a problem with the current offer cap. "PJM is supporting stakeholder consideration of proposals that could result in adjustments to the default offer cap, but it is unclear whether a proposal that results in such an adjustment will be approved," he said.

Should the proper offer cap be net ACR? "No. This assertion is dependent upon an expectation of performance assessment hours," Shields said. "Whether a given submitted offer was above the competitive level, even though it was within the rules, is a matter for FERC."

Comparison with 2017

The Monitor's quarterly report also repeated its concerns over generation subsidies, saying they "threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall." The Monitor wants to extend the minimum offer price rule (MOPR) to include existing units as well as new resources.

Although the Monitor found the capacity market problematic, it said PJM's energy markets produced competitive results in 2018. Compared with the first half of 2017, PJM saw the following in the first six months of 2018:

- Energy prices and fuel prices were higher and more volatile, resulting in higher margins for generation types. Average energy market net revenues increased by 160% for a new combustion turbine; 63% for combined cycle plants; 525% for coal plants; 44% for nuclear units; 10% for wind; and 20% for solar.
- Total energy uplift nearly tripled from \$49.7 million to \$146.4 million.
- Payments for DR programs increased 13.7% to \$271.7 million.
- Congestion costs increased by 214% to \$896.6 million. Auction revenue rights

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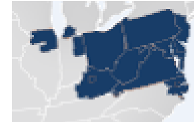

PC/TEAC Briefs

Manual 14F Changes

VALLEY FORGE, Pa. — Opponents and advocates of new rules to increase the importance of cost containment in transmission project proposals found themselves in uncommon agreement at last week's PJM Planning Committee meeting.

Both shared concerns over the RTO's plan to delay inserting some language for the new rules into Manual 14F.

Staff explained that it was a last-second decision meant to avoid confusion for those reading the manuals, and while stakeholders didn't fully support the explanation, they eventually agreed to endorse some of the modified manual revisions but defer voting on the cost-containment language.

The wide-ranging changes include revisions to PJM's processes for selecting "market efficiency" transmission projects and prequalification for submitting proposals. But stakeholders were focused on how PJM plans to implement the cost containment rules, which were endorsed earlier this year following a controversial stakeholder process. (See Cost Containment Clears MC Vote Despite PJM Plea.)

While some of the changes could be implemented immediately, two frameworks for comparing projects are being developed by PJM and its Independent Market Monitor. The first framework on construction costs is expected to be ready for use in December, while the second comparing return on equity and capital structures is expected by May. Because they aren't ready for use, staff decided to keep language revisions related to frameworks out of the public version of the manual. They are being maintained in an internal version that will be brought for stakeholder endorsement once the frameworks are finalized.

Jason Shoemaker | © RTO Insider

"The manual is a reflection of what's in effect today, and the comparative process is not a part of that today," PJM's Jason Shoemaker explained.

LS Power's Sharon Segner, who led the campaign to get the cost containment language endorsed, said PJM would be "picking and choosing" which parts of the approved revisions it's implementing.

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and financial transmission rights revenues offset only 50.7% of total congestion costs for the 2017/18 period, the first in which new rules required the allocation of balancing congestion to load instead of FTR holders. ARR and FTR revenues offset 98.1% of congestion costs for load during the 2016/17 planning period.

New Recommendation: FTR Liquidations

The report includes two new recommendations. The Monitor said PJM should set a high priority on reviewing how it liquidates FTR holdings, a recommendation prompted by GreenHat Energy's default in June, when it failed to pay a weekly invoice of $1.2 million. PJM has asked FERC to approve a waiver of rules that require immediate liquidation of a defaulting member's FTR portfolio (ER18-2068). (See related story, *PJM Reeling from Major FTR Default*, p.??.)

Bowring said he supports a change in the rules that allows PJM to liquidate the portfolio over a longer period. "These are long-term" positions, he noted.

New Recommendation: REC Transparency

The Monitor also said states with renewable portfolio standards should make the data on renewable energy credits (RECs) more transparent. D.C. and all but five of the 13 states in PJM have a mandatory RPS. Virginia and Indiana have voluntary standards, while Kentucky and Tennessee have no renewable targets. West Virginia repealed its voluntary standard in 2015.

Although FERC has determined that RECs are not regulated under the Federal Power Act unless they are sold in a bundled transaction that includes a wholesale sale of electric energy, RECs affect market prices and the mix of clearing resources, the report said. "Some resources are not economic except for the ability to purchase or sell RECs."

But data on REC prices, clearing quantities and markets are not publicly available for all states. In addition, RECs do not need to be consumed during the year of production, resulting in multiple prices for a REC based on the year of origination, the Monitor said.

"RECs markets are, as an economic fact, integrated with PJM markets, including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by PJM that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices, and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data."

The Monitor said the CO_2 price implied by REC prices ranges from $4.74/metric ton in D.C. to $35.41/ton in Pennsylvania, while solar RECs' implied prices range from $18.07/ton in Pennsylvania to $861.52/ton in D.C.

Those contrast with the 2018 average clearing price of $4.31/ton in the Regional Greenhouse Gas Initiative and the social cost of carbon, which is estimated at about $40/ton. "The impact on the cost of generation from a new combined cycle unit of an $800/ton carbon price would be $283.56/MWh. The impact of a $40/ton carbon price would be $14.18/MWh," the Monitor said. "This wide range of implied carbon prices is not consistent with an efficient, competitive, least-cost approach to the reduction of emissions."

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"This is kind of different than what was communicated to me just a few days ago as far as the approach, so I'm just concerned," she said.

Alex Stern of Public Service Electric and Gas, who largely opposed Segner throughout the cost containment battle, joined her in expressing concern because staff was not being clear with exactly what changes it was proposing from what was presented at the first reading last month and its meeting materials did not reflect the changes or represent the statements being made. His concern stemmed particularly from PJM's representation that it was removing language from the manual that had received stakeholder endorsement. Withholding the language related to the frameworks from the revisions up for endorsement wasn't clearly spelled out in the issue presentation PJM posted online prior to the meeting, and Stern questioned whether an endorsement should move forward when significant changes were being unclearly communicated immediately before the requested endorsement vote.

"This is a change also from my point of view," he said. "I'm not clear as to why you're carving it out."

PJM's Sue Glatz assured stakeholders that the withholding was limited to one section in the manual and a note would be included explaining that the material will be added later "so it's not being lost." She pointed out it would also be captured in the meeting's minutes.

PJM's Steve Herling said it wasn't the first time staff had used this tactic, so he didn't understand the "nervousness." Including it now wouldn't impact whether — or how quickly — the frameworks are completed, he said, and "it's highly likely" that additional manual language beyond what has already been approved will be needed to comprehensively detail the process.

"We can't post language … [that] will cause confusion if it's not ready to be implemented. People will be reading the manuals," he said. "When it is ready to be implemented, it will be posted."

"I think taking out the note causes more confusion than it helps," Stern said. "I'm actually confused the other direction how it helps to carve this out when there is the confusion. … I'm really not sure what people are concerned about."

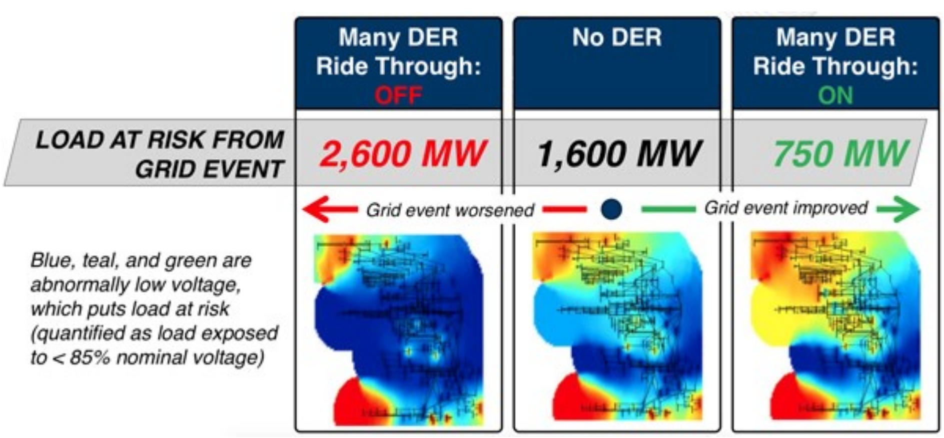
Once the situation was explained, Tonja Wicks of Duquesne Light said she was supportive of PJM's plan. American Municipal Power's Steve Lieberman said he was "sensitive" to Herling's points.

PJM eventually offered to remove the cost-containment language from the endorsement vote proceeding, with the Manual 14F changes focused on market efficiency procedures.

Following additional debate, Segner eventually decided to trust the process.

"I'm still a little confused, but I think we're on the right path, and I'm going to support this today," she said.

PJM's Mark Sims reviewed staff's planned timeline for implementing the cost containment measures. He explained that the comparative frameworks will help staff put proposals into a fuller context that includes constructability and financial data, along with risk evaluations.



A PJM analysis shows how DERs not using ride-through worsens system reliability, while using it improves reliability. | *PJM*

DER Ride-through

Staff are asking stakeholders for the opportunity to investigate whether certain operating parameters for inverter-based generators create a reliability risk for the grid.

PJM's Andrew Levitt presented a proposed problem statement and issue charge to determine whether the "ride-through" settings for distributed energy resources like residential wind and solar might create low-voltage risks. For safety and other reasons, DERs are configured to trip off within two seconds if they experience under- or over-voltage. As the amount of DERs grows, all of them tripping during such an event could exacerbate the situation. A new industry standard would address that issue by requiring DER to ride through certain system fluctuations.

Levitt had previously approached the Operating Committee in March about transmission owners taking the lead in implementing the new Institute of Electrical and Electronics Engineers standard. (See "Implementing DER Ride Through," *PJM Operating Committee Briefs: March 6, 2018*.)

Normal conditions wouldn't cause an issue, Levitt said, but "our relay clearing logic doesn't always work correctly" and could exceed the two-second threshold.

"Really, we would need to change our planning criteria under that kind of a scenario," he said. "Ride-through is good; lack of ride-through is bad."

Stakeholders noted several challenges that would have to be addressed, including the safety of utility workers working on lines, engineering and regulatory differences between the transmission and distribution systems, and the appropriateness of focusing on one technology type.

PJM will be hosting a technical workshop on the issue Oct. 1-2, Levitt said.

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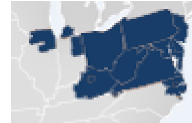

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CIRs

Staff announced that stakeholders impacted by planned revisions to how PJM calculates the output of generating units will have more than six years to prepare for the changes.

Changes planned for Manual 21 would revise and add detail to how PJM would test a generator's output and determine its net capability each year. Among the changes, the capacity factors for wind and solar units would be calculated using the median factors instead of the average. Throughout the year, PJM's Jerry Bell has been presenting analysis showing that the median more closely predicts actual performance than the average. (See "Skepticism of Gen Capability Changes Continues," *PJM Operating Committee Briefs: June 5, 2018*.)

However, the changes would mean that affected wind and solar units would have their capacity injection rights (CIRs) reduced. The potential reductions have concerned stakeholders because they have to pay for the CIRs. Bell has said the CIRs could be reallocated to other projects, but they would be constrained to projects on the same transmission line.

In an attempt to placate the concerns, Bell announced that the changes won't go into effect until the 2025 delivery year. Stakeholders will be alerted to CIR reductions by Aug. 1, 2024, and have to identify where they plan to move the CIRs by Jan. 1, 2025. They will then have until the end of that year to utilize them elsewhere. Any unused CIRs won't technically be lost until June 1, 2026.

"When it comes to incorporating intermittent resources … this has always been a work in progress," PJM's Tom Falin said. "This is just a further refinement in that area as we have accumulated more data."

The longer lead time seemed to have its intended effect.

"These changes are certainly much improved from the initial proposal," Dayton Power and Light's John Horstmann said.

TO Supplementals Discussion

PPL's Frank "Chip" Richardson announced that TOs will be hosting an online conference on Aug. 28 to discuss additional details of their plan to implement FERC's order from earlier this year requiring TOs to increase stakeholder engagement in the development of supplemental projects.

Supplemental projects are transmission construction initiated by TOs to address their own planning criteria and aren't in response to any wider planning criteria. FERC determined that PJM TOs' processes for developing those projects weren't in compliance with Order 890, sending reverberations through several stakeholder initiatives that most recently culminated in

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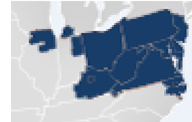

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the termination at July's Markets and Reliability Committee meeting of a task force focused on end-of-life supplemental projects. (See *PJM Stakeholders End Tx Replacement Task Force*.)

ARR Analysis Finds Infeasible Facilities

PJM's Xu Xu announced at last week's Transmission Expansion Advisory Committee meeting that the annual analysis of stage 1A auction revenue rights found one violation within PJM's territory and eight across flowgates to MISO. The analysis assesses the simultaneous feasibility of the ARRs' paths for a 10-year period.

The internal violation is expected to be addressed through a project that should be in service in 2020. Proposals to address the others are being considered in interregional planning with MISO.

Cost of Dominion's Haymarket Line Triples with Undergrounding

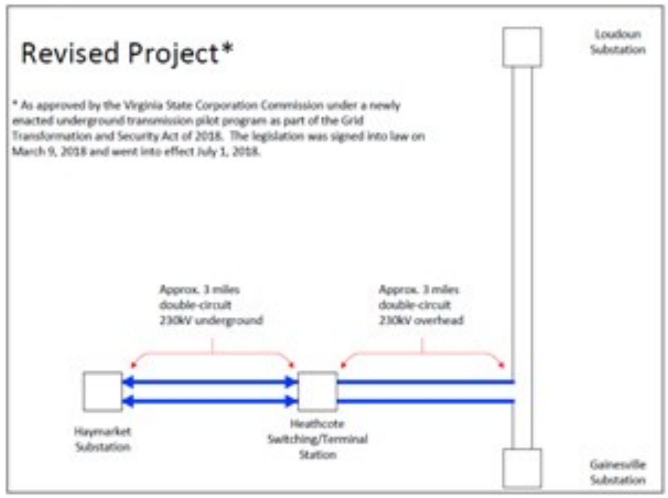
A decision by Virginia regulators to settle a controversy over a transmission line planned through a historical community through partial undergrounding will triple the cost of the line, staff confirmed.

A 6-mile 230-kV line planned for the area of Haymarket, Va., to feed new data centers received national attention after protesters raised concerns about Dominion Energy's plan to site it through a historically African-American community inhabited by descendants of emancipated slaves. The Virginia State Corporation Commission stepped in to approve project revisions under a newly enacted underground transmission pilot program as part of the Grid Transformation and Security Act of 2018, which went into effect July 1.

The revisions will underground roughly half the project, increasing costs from an initial estimate of between $45 million and $57 million to the new estimate of $174 million.

Because the proposal was a supplemental project initiated by Dominion, PJM confirmed that the entirety of the cost will be billed back to customers in Dominion's zone. However, that might change after the D.C. Circuit Court of Appeals rejected earlier this month PJM's cost allocation rules for supplemental projects that involve high-voltage lines. The rule, which had prohibited cost sharing for all supplementals, was remanded back to FERC for revision. (See *DC Circuit Rejects PJM Tx Cost Allocation Rule*.)

— Rory D. Sweeney



Dominion's supplemental project around Haymarket, Va. | *PJM*

SPP NEWS

3rd Time's a Charm for SPP Resource Adequacy Proposal

FERC last week approved Tariff revisions that will finally allow SPP to implement a resource adequacy requirement (RAR), reducing its planning reserve margin from 13.6% to 12% (ER18-1268).

The commission found the revisions will help ensure that sufficient capacity and planned reserves are maintained to meet SPP's balancing authority load requirements. The proposal also clarifies the types of authorities that may impose rules considered *force majeure* events, defined as "any curtailment order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities."

SPP revised its filing after FERC rejected a previous submission in September 2017, the second time its RAR proposal was found to be deficient last year. (See *FERC Again Rejects SPP's Resource Adequacy Revision*.)

The grid operator said its new Tariff Attachment AA includes all the terms and conditions relevant to the establishment, compliance and enforcement of the requirement that each load-responsible entity (LRE) in the SPP BA area maintain sufficient capacity and planning reserves to serve its forecasted load.

The RAR change will require LREs without sufficient generation to participate in bilateral capacity markets. FERC noted SPP's current market is "relatively net long" compared to the planning reserve margin, and that "likely many sellers of capacity are available to meet LREs' net peak demand and planning reserve margin."

The commission said it "continue[s] to encourage SPP and its stakeholders to consider the potential for the exercise of market power in the market for bilateral capacity as the overall reserve margin potentially shrinks in the future."

FERC suggested last year the proposal could be "more fully develop[ed]." It provided guidance that SPP require all power purchase agreements be backed by verifiable capacity; that the proposed treatment of firm power purchases and sales in the determination of net peak demand was unduly discriminatory; and that the RTO was unable to support its proposal to post publicly a list of all LREs unable to meet their RAR.

Tulsa Power Station | *Public Service Company of Oklahoma*

Westar Energy protested the most recent filing, separately and with Kansas Power Pool and Missouri Joint Municipal Electric Utility Commission. FERC sided with SPP in each of the arguments.

The RAR proposal is effective July 1, 2018. SPP said this would allow LREs to participate in a full cycle of the annual process before being exposed to a deficiency payment.

SPP's Board of Directors and stakeholders approved a package of policies in January 2017 that included reducing the RTO's planning reserve margin to 12%, which translates to a 10.7% capacity margin. LREs with resource mixes that are at least 75% hydro-based are allowed a planning reserve margin of 9.89%.

A stakeholder task force spent more than two years developing the package, which was projected to reduce SPP's capacity needs by about 900 MW and save members $1.35 billion over 40 years. (See "Stakeholders Endorse 12% Planning Reserve Margin, Policies," *SPP Markets and Operations Policy Committee Briefs*.)

SPP said it intends to recalculate the planning reserve margin every two years, "based on a probabilistic analysis using a loss-of-load expectation study." Any future changes to the planning reserve margin must go through the RTO's Regional State Committee, composed of state regulators, for approval.

Commission Rejects PMU Proposal over Cost Concerns

The commission rejected without prejudice to SPP a second Tariff change that would have required phasor measurement units (PMU) at new generator interconnections, saying the proposal's language is unclear (ER18-1078).

The American Wind Energy Association argued against the Tariff proposal, questioning the extent to which transmission owners should be required to fund PMU installations. AWEA raised concerns that SPP did not address funding obligations and said that, as drafted, the proposal would have allowed TOs to exercise market power and force interconnection customers to fund installations.

FERC found the revision's proposal to allow TOs the option to fund PMU installations only when their interconnection customers are affiliates "could result in affiliated interconnection customers having lower costs than non-affiliated interconnection customers." That would give affiliates an undue competitive edge, the commission said.

The agency said SPP did not address how TOs would account for the costs of the installations for their own generators or those of affiliated interconnection customers, and how the costs would be treated under the transmission formula rates in order to prevent unreasonable and/or unduly discriminatory rates.

The commission said any subsequent SPP proposal should clarify how TOs will treat PMU installation costs to avoid including them in transmission rates. Doing so, it said, could effectively result in non-affiliate customers subsidizing installations for generators belonging to TOs and/or their affiliated interconnection customers.

FERC also said SPP should develop Tariff language regarding responsibility for ongoing PMU communication and operation and maintenance expenses, and clarify

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SPP News

Task Force Begins Work on Admin Fee Changes

SPP's Schedule 1A Task Force last week kicked off an expected monthslong effort to develop an alternative rate structure to the RTO's current method for recovering its administrative costs.

The Finance Committee and SPP staff have both discussed changing the fee's billing units from transmission metrics to energy metrics by charging market transactions. The administrative fee, currently 42.9 cents/MWh, is collected under Schedule 1A of SPP's Tariff on contracts between transmission providers and customers. (See *SPP Stakeholders to Study Admin Fee Changes*.)

"From an SPP standpoint, what we have now works fine," CFO Tom Dunn told the group Aug. 8. "From a members' standpoint, feedback indicates it's not necessarily fine." He said transmission customers have complained of difficulty recovering the charges "through their rate base process."

While SPP's costs have increased with the addition of the Integrated Marketplace, "the number of folks paying [the costs] is not necessarily growing," Dunn said.

The task force discussed Dunn's July presentation to the Markets and Operations Policy Committee, which led to the group's creation. Members also took a first look at other grid operators' recovery mechanism.

The task force is scheduled to present a recommendation to SPP's Board of Directors and Members Committee in January.

SPP, MISO to Discuss Seams Transmission with Stakeholders

SPP and MISO are bringing stakeholders into the conversation as they continue efforts to improve transmission service along their seam.

The RTOs have agreed to remove their $5 million cost threshold and joint modeling requirement for transmission projects, two barriers that have prevented them from agreeing on interregional projects. (See *MISO, SPP Loosen Interregional Project Requirements*.)

The Interregional Planning Stakeholder Advisory Committee has scheduled a conference call on Aug. 27 to review with stakeholders the proposed changes to the interregional planning process.

Adam Bell, SPP's interregional coordinator, told the Seams Steering Committee on Aug. 8 that feedback to the changes has been "somewhat split," but staff are working to address stakeholder concerns.

"We need to move the conversation in a direction that everybody is happy with," Bell said. He said the grid operators plan to file the revised process this year so they can begin a new study in 2019.

The RTOs are also working to schedule a meeting this fall with staff and stakeholders to further explain the January "Big Chill" and actions being taken to prevent a reoccurrence. Colder-than-normal weather and generation shortfalls in MISO South on Jan. 17 led to MISO exceeding its regional dispatch limit on transfers between its northern and southern footprints across SPP's system.

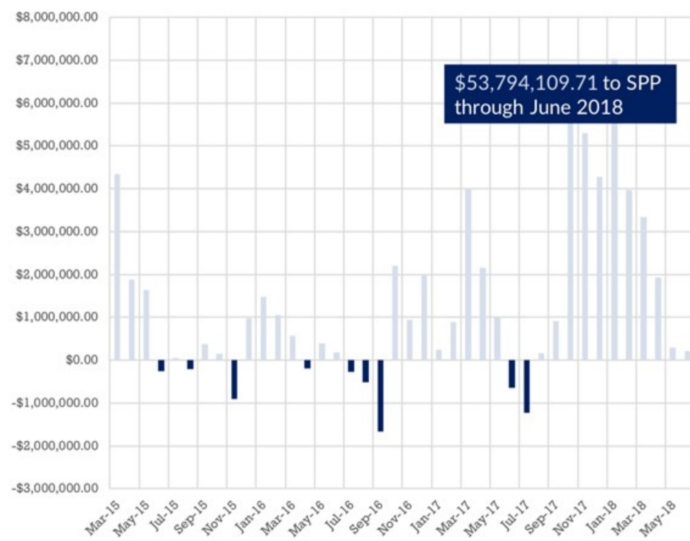
MISO Adds $213,189 in M2M Payments to SPP

June's market-to-market (M2M) payments between SPP and MISO came in at $213,189 in SPP's favor. While the amount was the lowest since last August, June was also the 11th straight month and 19th of the last 21 in which the payments have been in SPP's favor.

The RTO has recorded $53.8 million in M2M payments from MISO since the two began the process in March 2015.

Flowgates were binding for 713 hours in June.

— Tom Kleckner



M2M settlements (positive values are payments to SPP from MISO, and vice versa) | *SPP*

3rd Time's a Charm for SPP Resource Adequacy Proposal

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the extent to which the interconnection customer can use existing equipment, such as relays or digital fault recorders with phasor measurement capabilities, or provide data from PMUs already deployed and/or sited on the generator side of the interconnection point.

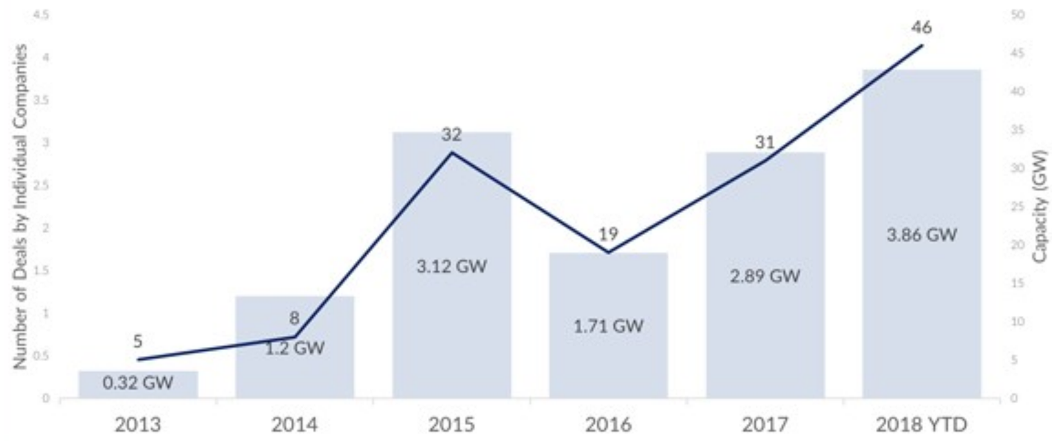
PMUs are devices that measure the voltage, frequency and angle of the grid's electrical waves, using a common time source for synchronization. The devices can take samples hundreds of times a second, while the standard supervisory control and data acquisition systems can have scan rates of 10 to 30 seconds.

The proposal cleared SPP's board and stakeholder groups in January.

— Tom Kleckner

Corporate Buyers Ink Record 3.5 GW in Renewables

By Rich Heidorn Jr.



Corporate renewable deals | *Rocky Mountain Institute*

Nonutility buyers have contracted for more than 3.5 GW of renewable energy thus far in 2018, breaking the annual record of 3.12 GW set in 2015, the Rocky Mountain Institute's Business Renewables Center (BRC) reported.

The 46 deals so far this year also best the 31 deals totaling 2.89 GW in 2017.

In total, U.S. corporate purchases of renewables have totaled 13.52 GW since 2008, according to the BRC, which says its member companies have been responsible for most nonutility transactions for renewable energy in the country.

The center says almost 60 companies have participated to date, up from four companies in 2013.

Facebook, which was one of the original four, pushed 2018's total to the record with its July 18 announcement that it will buy 437 MW of solar power from six projects for its Prineville, Ore., data centers.

Facebook is among 140 companies that pledged to transition to 100% renewables. Other large purchases this year came from AT&T, Walmart, Microsoft and Apple.

"We are bearing witness to unprecedented growth in this market, which is critical to achieving the goal of a clean, prosperous and secure low-carbon economy," said Jon Creyts, managing director at RMI.

The BRC, which launched in 2015 with about two dozen members, now has 250.

It helps simplify renewable purchases, offering procurement templates, primers and a Market Analysis Platform to identify the most attractive regions for wind or solar projects. BRC's Marketplace allows corporate buyers to search wind and solar power projects available for off-take and gives developers a way to market their projects and collect information from potential buyers.

BRC's goal is to facilitate procurement of 60 GW of renewables by 2030.

In addition to providing a way to enhance their green credentials, corporations increasingly see renewables as cost-effective. For example, storage and information management company Iron Mountain signed a 15-year power purchase agreement for wind in 2016 that it says will save it up to $500,000 in power costs annually. (See *Cost Trends Favor Renewables Despite Coming Policy Shifts*.)

In 2015, corporations passed utilities as the top purchaser of wind power.

However, some corporate buyers have complained their efforts have been hamstrung by insufficient transmission to move Midwest wind. (See *Is RTO Tx Planning Hampering Green Corporate Goals?*)

OGE Earnings Up, but Fall Short of Expectations

Oklahoma City-based OGE Energy said last week that a strong regional economy and positive regulatory developments led to an improved second quarter for the company, which reported earnings of $110 million ($0.55/share), compared to $105 million ($0.52/share) the year prior.

Earnings just missed Zacks Investment Research's consensus estimate of 57 cents/share.

CEO Sean Trauschke said Oklahoma Gas & Electric continues to add customers near its historical average of 1%, the state's unemployment numbers are at or under the national average and tax revenues are "now growing solidly again."

"We are seeing growth on our system driven by our low rates and quality service. I'm very proud of our team's work to deliver this competitive advantage to the communities we serve," Trauschke told financial analysts during an Aug. 9 conference call.

"Our core is solid, our employees are doing a great job, and we're effectively executing on our plans across every area of the company," he said.

OGE in June reached a $64 million settlement with the Oklahoma Corporation Commission that provides full recovery of its investment in the newly converted Mustang Energy Center. The plant's seven gas-fired combustion turbines have had more than 1,200 starts this year, Trauschke said.

OGE Energy Holdings, which includes OGE&'s 25.6% limited partner interest and 50% general partner interest in Enable Midstream Partners, contributed 11 cents/share to earnings and $35 million in cash distributions.

"Enable continues to perform very well and their financial metrics are strong," Trauschke said. He told analysts OGE has not changed its thinking around how the petroleum-gathering company is organized.

— Tom Kleckner

COMPANY BRIEFS

Northern Pass Appeals Denial to NH Supreme Court

Northern Pass Transmission on Aug. 10 filed an appeal with the New Hampshire Supreme Court challenging the state Site Evaluation Committee's recent decision denying it a permit for its proposed transmission project.

The Eversource Energy subsidiary said proponents of the project think a favorable ruling by the court will enable it to return to the SEC next year for additional evaluation.

More: *Northern Pass*

SCE&G Asks 4th Circuit To Halt Rate Cut

South Carolina Electric and Gas on Aug. 8 asked the 4th U.S. Circuit Court of Appeals for an emergency order to stop a temporary 15% cut to its electric rates that went into effect Aug. 7, pending its appeal of a lower court's ruling against it.

The court said the motion by the SCANA subsidiary will be assigned to a three-judge panel and responses to it are due Aug. 15.

The rate cut is the result of a law passed by the South Carolina General Assembly aimed at stopping SCE&G from charging customers for its share of the failed $9 billion attempt by it and Santee Cooper to expand the V.C. Summer Nuclear Station.

More: *The Charlotte Observer*

FERC Reinstates Invenergy Solar Farm to PJM Queue

FERC on Aug. 7 restored a proposed Ohio solar facility's position in PJM's interconnection queue, granting the developer a waiver for an accounting error that caused it to miss a milestone payment.

Invenergy Solar Development North America requested the waiver after PJM notified the company June 21 that it had removed the 170-MW facility in Hardin County from the queue because of its failure to make an $85,000 system impact study deposit. Invenergy said it wired PJM the money the day it was notified and that it had otherwise met all its obligations in the interconnection process.

The commission's order approving the waiver, which reinstated Invenergy in queue position AD1-130, noted that PJM "sees no potential adverse impacts" from the reinstatement.

More: *ER18-1985*

PJM Signs New Deal With Monitoring Analytics

The PJM Board of Managers has approved a new market monitoring contract with Monitoring Analytics, PJM CEO Andy Ott announced Aug. 8. The new contract, which must be approved by FERC, extends a pact signed in 2013 that expires in December 2019.

PJM said it would provide stakeholders with details on the agreement at the Aug. 23 Markets and Reliability Committee meeting.

Monitoring Analytics President Joe Bowring has served as PJM's Market Monitor since 1999. He formed the independent company after leaving PJM's staff following a 2007 dispute, when he accused then-PJM President Phil Harris of attempting to muzzle him and cutting his budget.

More: *PJM, Monitoring Analytics Sign New Contract*

SC Senate Sues McMaster Over Utility Board

The South Carolina Senate sued Gov. Henry McMaster on Aug. 7, challenging his unilateral appointment of former Attorney General Charlie Condon as chairman of state-owned utility Santee Cooper's board of directors.

The Senate failed to confirm Condon, nominated by McMaster in March, before the legislative session ended in June. The governor said the position can't remain vacant, though William Finn currently serves as acting chairman.

The lawsuit asks the state Supreme Court to take the case directly and settle it as quickly as possible.

More: *The Post & Courier*; *The State*

Dominion: SCANA Merger To Close in December

A Dominion Energy spokesperson Aug. 6 said the company expects its proposed merger with SCANA to close by the end of the year.

The South Carolina Public Service Commission will begin hearings on the deal in November, and the North Carolina Utilities Commission will begin reviewing it sometime in fall, Dominion said. The companies have already received approvals from the Georgia Public Service Commission, FERC and the Federal Trade Commission.

Also on Aug. 6, SCANA subsidiary South Carolina Electric and Gas announced that customers would see a 15% rate decrease in their bills beginning Aug. 7.

More: *Journal Scene*

Murray Funding Oppo To Freshwater Wind Farm

Murray Energy has been funding opposition to the Icebreaker Wind project, a wind farm in Lake Erie off Ohio that if built would be the first freshwater offshore wind project in North America.

Documents show that developer Lake Erie Energy Development Corp. presented evidence to the Ohio Power Siting Board, which is considering the project, that Murray paid a consultant to produce a report about the economic viability of the project, as well as the legal fees for two residents of the lakeside village of Bratenahl who are challenging the project before the board.

LEEDCo did not allege Murray broke any laws. A Murray spokesperson confirmed the company's activities to *The Plain Dealer*.

More: *Greentech Media*; *The Plain Dealer*

Evergy to Close Fossil Units Earlier than Expected

The newly merged company Evergy will close units at three of its fossil fuel-fired plants in Kansas in the next four months, years earlier than originally expected.

Evergy will close the two units at the coal-fired Tecumseh Energy Center; two of the Gordon Evans Energy Center's gas-fired units; and two gas-fired units at the Murray Gill Energy Center.

The merger of Westar Energy and Great Plains Energy "gave us the opportunity to move the retirement up a little bit sooner than we had originally planned," an Evergy spokesperson said.

More: *Topeka Capital-Journal*

Federal Briefs

Renewables Topped Nuclear in US Generation in First Five Months

Renewable generation produced 20.17% of U.S. electricity in the first five months of the year, slightly more than nuclear generation's 20.14%, according to Energy Information Administration data compiled by Ken Bossong of the Sun Day Campaign.

Renewables also provided a larger share of U.S. power than nuclear generation in the first three months of last year. Additionally, they provide more power than nuclear generation in more than half the states, according to Sun Day.

More: *Greentech Media*

Politico: Trump to Nominate DOE Official to FERC

Citing three sources, *Politico* reported Aug. 8 that President Trump intends to nominate Bernard McNamee, executive director of the Energy Department's Office of Policy, to fill the vacancy left by departing Commissioner Robert Powelson at FERC.

McNamee has been with the Texas Public Policy Foundation and served as aides to Texas Attorney General Ken Paxton and Sen. Ted Cruz (R-Texas).

The vetting process for McNamee is still ongoing, *Politico* said.

More: *Politico*

Documents Show Trump Admin Edited Lab Report

The Trump administration pushed the authors of a report to highlight outages of natural gas-fired generation during extreme weather events to tout the value of coal-fired plants, newly released documents show.

Correspondence obtained by the Sierra Club shows Energy Department officials hoping for more cold snaps like the so-called "bomb cyclone" that hit the Northeast in January. They told researchers at the department's National Energy Technology Laboratory that such events show "the need for system planners to more strongly consider generator performance during extreme weather events, particularly for natural-gas fired units."

The report was cited by FirstEnergy Solutions in its request under Federal Power Act Section 202c that the department issue an emergency order that PJM to compensate coal-fired and nuclear power plants that have 25 days of onsite fuel. (See *FES Seeks Bankruptcy, DOE Emergency Order*.)

More: *Bloomberg*

Senators Urge Caution on Nuke Decommissioning Rule

Four senators wrote to the Nuclear Regulatory Commission on Aug. 3, expressing concern over a proposed rule that would, among other things, eliminate the need for nuclear plant operators to send requests for exemptions from certain decommissioning requirements.

"The proposed rule, as presented by NRC staff, would not establish the proper checks to ensure the safety and security of these plants as they move through the full decommissioning process," the senators wrote.

Sens. Ed Markey (D-Mass.), Kirsten Gillibrand (D-N.Y.), Bernie Sanders (I-Vt.) and Kamala Harris (D-Calif.) signed the letter.

USDA Awards $345.5M In Loans for Rural Tx

The Department of Agriculture on Aug. 6 announced it has awarded $345.5 million in loans for 20 transmission projects to improve electric service in rural areas.

The department granted the loans through its Electric Infrastructure Loan Program, which finances projects in communities with less than 10,000 residents.

The loans include $7.75 million to Goodhue County Electric Cooperative Association in Minnesota to build 28 miles of transmission and improve 72 miles of existing line. They also include a total of $7.9 million for smart grid technology that the department said would improve reliability and efficiency.

More: *USDA*

Puerto Rico Nearly Back to Full Service

Energy Information Administration data show that commercial and industrial electricity sales on Puerto Rico are back to pre-Hurricane Maria levels, while residential sales are still lagging slightly behind.

The Puerto Rico Electric Power Authority on Aug. 3 reported that only 104 customers remain without power. The island territory's blackout of more than 10 months constitutes the longest in U.S. history.

More: *Greentech Media*

State Briefs

MARYLAND

Hogan to PJM: Stop Transource Project

Gov. Larry Hogan wrote to PJM last month asking it to halt Transource Energy's Independence Energy Connection transmission project.

The project includes two segments, in Washington and Harford counties, that run for 45 miles total across the Pennsylvania border. "As currently designed, the project will take prime agricultural land out of production, including land that is in permanent agriculture easements," Hogan wrote.

Hogan's office on Aug. 8 said it has yet to receive a response from PJM, which included the project in its Regional Transmission Expansion Plan in 2016 as a market efficiency project. It has yet to be approved by the Public Service Commission.

More: *Herald-Mail Media*

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STATE BRIEFS

Continued from page 35

MINNESOTA

PUC Gives Xcel Customers $134M of Company's Tax Savings

The Public Utilities Commission voted 5-0 on Aug. 9 to distribute all but $2 million of the $136 million that Xcel Energy will save as a result of the Tax Cuts and Jobs Act to the utility's customers.

The decision means an average residential electric customer of Xcel's, who pays $85 to $90 per month, will get a one-time bill credit of about $45.

The $2 million not refunded to Xcel customers will go to Power On, a program that provides low-income residents with assistance on their electric bills.

More: *Star Tribune*

NEW JERSEY

CPV Seeking to Add Gas Plant In Woodbridge Township

CPV's existing Woodbridge Energy Center

Competitive Power Ventures is seeking approval from the Woodbridge Township Planning Board to build a natural gas-fired power plant next to the 725-MW one it already operates in the township.

The proposed plant is the fourth natural gas-fired power plant for which approvals are being sought in the state. The other three are in Cape May, North Bergen and Holland Township.

CPV is seeking to build the plants despite Gov. Phil Murphy's declaration that he wants all power sold in the state to come from renewable sources by 2050.

More: *NJ Spotlight*

NEW YORK

NYISO to Help in State's Offshore Wind Study

NYISO and several state entities have signed a memorandum of understanding to conduct a study on successful offshore wind transmission models, with a focus on those in Europe, Gov. Andrew Cuomo announced Aug. 8.

The New York Power Authority will lead the study, which aims to learn from European infrastructure design, best practices in interconnecting wind facilities and successes in reducing the cost of delivering wind energy to consumers. Joining it, along with the ISO, are Consolidated Edison, the New York State Energy Research and Development Authority, and the Long Island Power Authority.

"The NYISO is pleased to partner with the New York Power Authority and the other key energy stakeholders on this important study, which will help the state establish the best course of action in the pursuit of offshore wind energy investments," ISO CEO Brad Jones said in a statement.

More: *Andrew Cuomo*

RHODE ISLAND

Green Industry Jobs Growth Continues Decline

While cleantech jobs in the state are still growing, that growth has slowed considerably, a new report shows.

According to the state's 2018 Clean Energy Industry Report, 561 jobs were added last year, an increase of 3.6%. That continues a downward trend, from 40% in 2015 and 11% in 2016. As of the end of 2017, the industry employs 15,866 in green transportation, renewable energy, renewable heating and cooling, and energy efficiency.

The report, published jointly by the Office of Energy Resources and the Rhode Island Commerce Corp., points to the national drop in solar industry jobs. It cites a report by The Solar Foundation that blames this decline on a surge in solar installations in 2016 and the Trump administration's tariffs on solar module manufacturers.

More: *ecoRI News*

SOUTH DAKOTA

County Considering Zoning Amid Con Ed Wind Proposal

The Campbell County Commission has hired a contractor to draft ordinance and zoning regulations after Consolidated Edison proposed expanding an existing wind farm.

Commission Chairman Scott Rau said the measure isn't intended to be "just wind-oriented." But, he said, "We want to have zoning ordinances in place so they can't just put it wherever they want to. We have no regulations at all."

More: *The Associated Press*

TEXAS

Community Solar Project Builder Faces Tax Liability

The Bexar County Appraisal District has ruled that the owners of the individual panels in a community solar project will not be assessed property taxes on them.

Instead, the district said, Clean Energy Collective, which built the project, will have to pay property taxes on the equipment it owns that moves power from the project to the grid.

A spokesman for Clean Energy Collective said the Louisville, Colo., company thinks its equipment also is exempt from property taxes.

More: *Rivard Report*

VIRGINIA

Dominion, Orsted File Offshore Wind Proposal

Dominion Energy and Orsted have filed a proposal with the State Corporation Commission to build two 6-MW offshore wind turbines. They would be located approximately 43 km off the coast of Virginia Beach.

"The announcement represents a significant step toward harnessing Virginia's offshore wind energy resource and the many important economic benefits that this industry will bring to our commonwealth," Gov. Ralph Northam said.

More: *Offshore Wind Journal*