

Full PJM Study Makes Case for Fuel Security Payments

By Rory D. Sweeney

The full [report](#) on fuel security in PJM's footprint that CEO Andy Ott teased during a D.C. press conference on Nov. 1 shows that the grid is reliable in all but extreme scenarios and will remain so — as long as resources are compensated for being fuel-secure.



PJM CEO Andy Ott | © RTO Insider

"This analysis demonstrates that the PJM

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PJM Moving Quickly to Make Board's Price Formation Deadline

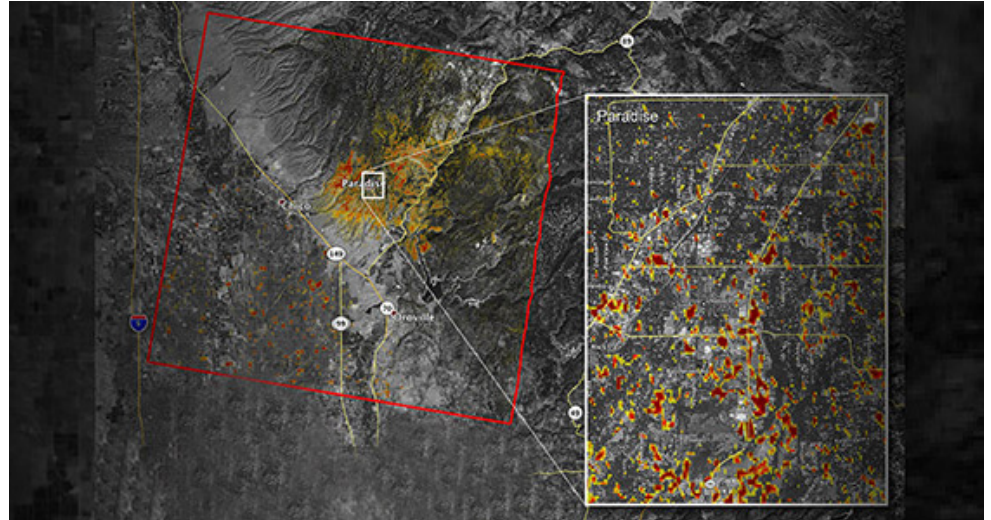
(p.21)

State Regulators Still Frustrated with PJM

(p.28)



Bernard McNamee was sworn in as FERC commissioner on Dec. 11, five days after he was confirmed 50-49 by the Senate. McNamee, who replaced Robert Powelson, will attend his first open meeting on Thursday. | [FERC](#)



PG&E Grapples with Line Safety After Camp Fire

NASA mapped damage to Paradise, Calif., from the Camp Fire, the deadliest wildfire in state history. The color variation from yellow to red indicates increasingly more significant changes in the ground surface. (p.5) | [NASA/JPL-Caltech](#)

Calif. Regulators to Scrutinize De-energization

(p.4)

Mass. Offshore Lease Auction Nets Record \$405 Million

By Michael Kuser

Offshore wind in the U.S. hit a new milestone Friday when the eighth federal lease auction brought in \$405 million for three sites — about six times the revenue from all previous auctions combined.

Eleven companies participated in 32 rounds of bidding. The winners were Equinor, a Norwegian state-controlled company formerly known as Statoil; Mayflower Wind Energy, a joint venture of Shell and EDP Renewables; and Vineyard Wind, a joint venture by Iberdrola and Copenhagen Infrastructure Partners.

The three lease areas are located 19.8 nautical miles from Martha's Vineyard and 16.7 nautical miles from Nantucket. The areas total 388,569 acres and, if fully developed, could support 4.1 GW of wind generation, or enough electricity to power about 1.5 million homes.

"Wow ... we are truly blown away by this result," Walter Cruickshank, acting director

of the Bureau of Ocean Energy Management, which conducted the auction, [said](#) on a press call.

"The intense competition we've seen in this

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OMS Names New Executive Director

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FERC Rejects SPP Confidentiality over NERC Fine

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FERC Clears Cleco to Buy NRG Plants in MISO South

(p.31)

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CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

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

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

Art Director
Mitchell Parizer 718-613-9388

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

Associate Editor
Shawn McFarland 570-856-6738

CAISO/West Correspondent
Hudson Sangree 916-747-3595

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

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Rory D. Sweeney 717-679-1638

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

Subscriptions

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

Account Executive
Marge Gold 240-750-9423

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

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Correction

A story in the Dec. 11 edition of RTO Insider, [MISO, Stakeholders at Odds over Resource Availability Filings](#), incorrectly listed Jim Dauphinais' affiliation and misnamed the Coalition of MISO Transmission Customers. Dauphinais is a consultant with Brubaker and Associates Inc.

STAKEHOLDER SOAPBOX

Large Buyers: Don't Stop Our Renewable Purchases

By Jeff Dennis and Caitlin Marquis



Jeff Dennis



Caitlin Marquis

In response to FERC's directive to address the impacts of state policies on capacity prices, PJM has proposed a sweeping approach that could put at risk a broad set of transactions for renewable energy that have nothing to do with any state policy or mandate. On behalf of the Advanced Energy Buyers Group, a collection of large companies ranging from technology to retail to manufacturing, we urge FERC to avoid disrupting the voluntary market for renewable energy by rejecting PJM's approach.

Companies involved in the Advanced Energy Buyers Group are committed to increasing their use of advanced energy, with many entering into contracts to develop renewable energy projects to meet their own business needs, completely independent of state mandates or incentives. We are concerned that PJM's proposal, if adopted by FERC, would unfairly apply to some of these voluntary transactions the same measures intended to "correct" a market distortion supposedly caused by so-called "material subsidies" provided by states. This could threaten the continued growth of the quickly expanding voluntary market for renewable energy in the PJM footprint, and the jobs and other economic benefits that growth brings to states and communities in the region even as it gives companies the clean energy they seek.

According to FERC, generating resources that receive revenue as a result of state renewable portfolio standards or zero-emissions credit (ZEC) programs are able to submit offers in PJM's capacity auctions at a lower price than they would otherwise. FERC claims that these offers result in "artificially" lower prices, harming other suppliers that do not receive such revenue. To address this alleged price suppression, FERC ordered PJM to expand its minimum offer price rule (MOPR) — which requires capacity suppliers to make offers at

or above a predetermined minimum value — to apply to any capacity resource receiving revenues from state policy programs.

To its credit, PJM correctly acknowledged that voluntary renewable energy purchases should be exempted from the expanded MOPR because any revenue received from such purchases aren't the result of any state mandate or policy. PJM goes on, however, to state that any renewable energy certificates (RECs) purchased through brokers or intermediaries will be assumed to be serving state policy needs rather than meeting voluntary market demand. This means that only those RECs that are purchased by voluntary buyers through direct, bilateral transactions would be exempt from MOPR requirements. Other renewable energy transactions that use different structures would face the possibility that they could be subject to the MOPR. That matters because application of the MOPR could force certain renewable energy projects out of the capacity market, depriving them of legitimate revenue.

Applying the MOPR in such a broad fashion would fail to satisfy FERC's legal obligation to narrowly tailor such mitigation to the market harm it identified, i.e., the supposed price-suppressive impacts of state-directed revenues. Equally important, it would fail to account for how the voluntary market actually works, especially the variety of transaction structures and market actors, including REC brokers and intermediaries, that support voluntary renewable energy purchases.

Direct REC purchases from renewable energy projects are an important segment of the voluntary market, to be sure. But so too are "unbundled" RECs purchased through brokers or intermediaries. Renewable energy buyers range from residential consumers to small businesses to large international corporations. Many of these buyers rely on unbundled RECs to some degree, and in 2017 unbundled REC sales accounted for nearly half (46%) of all voluntary market sales of renewable energy. The voluntary purchase of these unbundled RECs by buyers who (unlike utilities and other electricity suppliers) have no state-imposed obligation to purchase renewable energy does not contribute to the state's RPS or other policy mandate. These RECs are effectively retired, rather than used for

Advanced Energy Buyers Group Membership



Some of the members of the Advanced Energy Buyers Group | [Advanced Energy Buyers Group](#)

compliance with state requirements — which is why they can be counted toward corporate sustainability goals.

Even for large companies that pursue direct contracts with renewable energy projects, unbundled RECs purchased from brokers or other intermediaries can play an important part in an overall renewable energy strategy. Unbundled RECs allow companies to purchase renewable energy without a long-term, large-scale commitment to a single project, as part of a diversified renewable energy portfolio. Unbundled RECs also allow companies to meet renewable energy goals while they pursue direct renewable energy contracts, which takes time.

Many companies and other renewable energy buyers rely heavily on RECs purchased through brokers or intermediaries — to the tune of 51 million MWh across the country last year. These RECs have contributed to a rapid expansion of voluntary corporate renewable energy deals in the PJM region in just the past few years. One voluntary REC getting swept up in mitigation that is, by the terms of FERC's directive, supposed to be narrowly focused on material subsidies provided by states is one too many, and PJM's approach could sweep up nearly half the market.

Accordingly, we urge the commission to ensure that any changes to PJM's capacity market do not, even inadvertently, unfairly cripple the voluntary market for renewable energy. ■

Caitlin Marquis is manager of federal and state policy for the Advanced Energy Buyers Group, a business-led coalition of large energy users engaging on policies to expand opportunities to procure advanced energy to meet their operational needs.

Jeff Dennis is general counsel, regulatory affairs, for Advanced Energy Economy, a national association of businesses making the energy we use secure, clean, and affordable. AEE facilitates and supports the work of the Advanced Energy Buyers Group.

CAISO/WECC NEWS



Calif. Regulators to Scrutinize De-energization

By Robert Mullin

The California Public Utilities Commission on Thursday voted to examine its rules allowing the state's investor-owned utilities to de-energize power lines in cases of dangerous wildfire conditions "that threaten life or property."

The practice of de-energization will get a dedicated *proceeding*, separate from another rulemaking effort set out in Senate Bill 901 to address utility wildfire mitigation. De-energization will be discussed in the SB901 proceeding as one of a broader set of fire prevention measures.

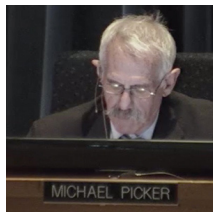


Carla Peterman

"We can't not act" on the de-energization issue, Commissioner Carla Peterman said during the Thursday voting meeting, her last with the commission. De-energization "is an option we don't want to exercise often, but we do want the option to exercise."

Commissioner Cliff Rechtschaffen said the issue was "worthy" of its own proceeding because de-energizing a line is a "significant event [with] significant consequences."

"I support having this as a separate proceeding. ... It is a requirement as part of the wildfire mitigation plans that the utilities now have to submit yearly that they include their de-energization protocols," Rechtschaffen said. "[CPUC] President [Michael] Picker and I are the assigned commissioners partnered on the wildfire safety plans, and we're committed to making sure that this proceeding is closely coordinated with that proceeding as we go forward."



Michael Picker

Proactive

The CPUC adopted the de-energization rules in July in response to the growing threat of

wildfires throughout the state, especially in the expansive Pacific Gas and Electric and Southern California Edison service areas. Regulations around "proactive" shutoffs had previously applied only to San Diego Gas & Electric, which serves a historically highly fire-prone area.

"Since then, the topic of proactive power shutoff has reached a lot of people and has become a [hot] point of discussion," CPUC Director of Safety and Enforcement Elizaveta Malashenko told the commission.

Among other mandates, the July rules require all IOUs to notify customers before de-energizing facilities and report to the commission after the fact (Res ERSB-8).

But Malashenko noted that industry stakeholders and members of the public have raised "a range of concerns" about the program and that utilities are increasingly "proactively de-energizing" their lines. (See [Fire Season Becomes Blackout Time in California](#).)

"In my mind, the type of issues that would come up in [this] rulemaking as related to de-energization is how much the utilities should be using that as a tool, as opposed to mitigating wildfires in other ways, such as introducing coated conductors or undergrounding lines, or increasing their ability to detect faults faster, and things like that," she said.

A CPUC staff report on the new rulemaking indicates the proceeding will focus on:

- Examining conditions under which planned de-energization is practiced;
- Developing best practices and ensuring an orderly and effective set of criteria for evaluating de-energization programs;
- Ensuring electric utilities coordinate with state and local level first responders and align their systems with the Standardized Emergency Management System framework;
- Reducing the impact of de-energization on vulnerable populations;
- Examining ways to reduce the need for de-energization;
- Ensuring effective notice to affected stakeholders of possible de-energization and follow-up notice of actual de-energization; and
- Ensuring consistency in notices of and re-



Elizaveta Malashenko

porting of de-energization events.

Digitize the Landscape

During the meeting, Picker emphasized the importance of learning from SDG&E's experience from de-energization — without leaning too heavily on it.

"Utilities have always de-energized," Picker said. "We have so far required them to plan a little ahead and to provide notification, but what could we learn from San Diego? What should be applied elsewhere? And how do we know what will work in other parts of the state?"

Picker pointed out that in order to avoid de-energizing lines, SDG&E "digitized the landscape" in its service territory.

"They put sensors in a number of places," he continued. "They put weather monitors, wind monitors, moisture monitors and cameras in places you wouldn't expect to see that. They began to collect information. They began to look carefully at very granular conditions in specific parts of their service territory at a much finer level than has ever been modeled before."

Picker said SDG&E over time developed "a much finer sense of where and when to de-energize, and what were the consequences." But he also acknowledged that SDG&E has a much smaller service territory than either PG&E and SCE.

"When you begin to look at the service territories of the other regulated utilities ... we may be able to expedite their processes, but they're still going to have to go through that data-monitoring, data collection, analysis, modeling and eventual testing process," Picker said.

"I want to be honest about what we'll be able to achieve. I don't think we'll have a perfect set of rules right away." ■



PG&E Grapples with Line Safety After Camp Fire

By Hudson Sangree

PG&E last week reported additional problems with its transmission lines prior to the deadly Camp Fire, vowed to enhance its grid safety and asked state regulators to approve a more than \$1 billion rate hike, largely to help it harden its grid against wildfires.

"We are acting decisively now to address these real and growing threats, and we are committed to working together with our regulators, state leaders and customers to consider what additional wildfire safety efforts we can all take to make our communities safer," company CEO Geisha Williams said in a news release.

PG&E filed a supplemental report Dec. 11 with the California Public Utilities Commission, detailing problems with its lines near the Camp Fire on the morning the fire started. It also released the [report](#) to the public.

The Camp Fire killed 85 people and leveled the town of Paradise, Calif., making it by far the deadliest wildfire in state history. It started at 6:33 a.m. on Nov. 8 near Tower :27/222 on PG&E's Caribou-Palermo 115 kV transmission line, the California Department of Forestry and Fire Protection (CAL FIRE) and PG&E [reported](#).

For the first time publicly, PG&E in its report provided detailed information about the problems it experienced on that line and in other areas of rural Butte County preceding the Camp Fire.

"On Nov. 8, 2018, at approximately 6:15 a.m., the PG&E Caribou-Palermo 115-kV transmission line relayed and de-energized," the company told the PUC. "At approximately 6:30 a.m., a PG&E employee observed fire in the vicinity of Tower :27/222, and this observation was reported to 911 by PG&E employees.

"In the afternoon of Nov. 8, PG&E observed damage on the line at Tower :27/222 located near Camp Creek and Pulga Roads, near the town of Pulga. Specifically, an aerial patrol identified that on Tower :27/222, a suspension insulator supporting a transposition jumper had separated from an arm on the tower. The suspension insulator and the transposition jumper remained suspended above the ground."

State fire investigators denied PG&E access to the site for a week but eventually requested the company's help collecting evidence from Tower :27/222 and the adjacent Tower



PG&E outlined its efforts to deal with wildfire threats in a report to the CPUC. | PG&E

:27/221, with PUC staff observing, the utility said.

"At the time of the collection at Tower :27/222, PG&E observed a broken C-hook attached to the separated suspension insulator that had connected the suspension insulator to a tower arm, along with wear at the connection point," PG&E wrote. "In addition, PG&E observed a flash mark on Tower :27/222 near where the transposition jumper was suspended and damage to the transposition jumper and suspension insulator.

"At Tower :27/221, there was an insulator hold-down anchor that had become disconnected. The insulator hold-down anchor is not an energized piece of equipment. After the evidence collection, CAL FIRE released the site. PG&E has not yet made repairs at either tower or restored service."

Another incident occurred nearby on Nov. 8 at 6:45 a.m., when "the PG&E Big Bend 1101 12-kV circuit experienced an outage. Four customers on Flea Mountain were affected by the distribution outage," the company said. The next day, a PG&E employee "observed that the pole and other equipment was on the ground with bullets and bullet holes at the break point of the pole and on the equipment."

After the Camp Fire tore through Paradise in a single day, there was speculation that the Flea Mountain site or another site may have been a second ignition point for the Camp Fire, but so far those reports remain unverified.

PG&E said it's continuing to investigate the Pulga Road and Flea Mountain incidents and two other reported problems with its equipment in the week following the Camp Fire.

"The cause of these incidents has not been determined and may not be fully understood

until additional information becomes available, including information that can only be obtained through examination and testing of the equipment retained by CAL FIRE," the utility said. "PG&E is cooperating with CAL FIRE."

In the meantime, PG&E said it would implement additional safety measures to decrease fire risks to threatened communities. The measures include inspections of more than 5,550 miles of transmission lines and 50,000 transmission poles and towers in risk-prone areas, increased vegetation management along its lines and more real-time monitoring of fire conditions.

By 2022, the company said, it will add 1,300 new weather stations, with one every 20 miles in high-risk areas, and install 600 high-definition cameras. The proposed steps align with measures already undertaken by San Diego Gas & Electric to prevent fires and avoid pre-emptive shutoffs of transmission lines in its service area. PUC President Michael Picker praised SDG&E's long-term efforts Thursday and touted them as a model for the state's other investor-owned utilities ahead of a commission vote to examine the practice of de-energizing lines in fire-prone conditions. (See [Calif. Regulators to Scrutinize Line De-energization](#).)

PG&E is facing a snowballing number of lawsuits for the Camp Fire, billions of dollars in financial exposure for its role in 2017's devastating wine country fires and talk of the state stepping in and breaking up the IOU and making its pieces public. (See [Camp Fire Prompts Talk of PG&E Bailout or Breakup](#).) It watched its stock price plummet in November before recovering some ground. (See [Destructive Fire Drives Down PG&E Stock](#).)

Continued on page 6

CAISO/WECC NEWS



CAISO Rev Requirement Shrinks in 2019, Despite RC Role

By Hudson Sangree

FOLSOM, Calif. — CAISO's 2019 revenue requirement will be less than this year's, despite hiring and costs associated with its planned new role as reliability coordinator for most of the West, staff members told the ISO's Board of Governors on Thursday.

The ISO's proposed revenue requirement for 2019 is \$193.5 million — \$3.7 million less than in 2018. That's within "the tight range that the ISO has maintained over the past 13 budget cycles and beneath the FERC-approved cap of \$202 million," CFO Ryan Seghesio wrote in a memo to the board.

Total outlays will grow to \$230.9 million from \$217.4 million in 2018, but new revenues from the RC business as well as increased gains from the Western Energy Imbalance Market will offset that spending rise by \$7.2 million. A \$13.5 million operating cost reserve adjustment for overcollection this year will provide an additional offset.



April Gordon | © RTO Insider

Operations and maintenance costs will rise by \$10.5 million, April Gordon, director of financial planning and procurement, said at the board meeting. CAISO CEO Stephen Berberich added that the additional spending was primarily from "adding headcount" for the ISO's new RC component.

The ISO is set to take over RC services from Peak Reliability for the bulk of Western Interconnection states, starting in California in July. (See [RC Transition Fraught With Pitfalls, WECC Hears.](#))

The PUC said recently it would expand its probe into PG&E's safety practices following the Camp Fire. That investigation started after the fatal explosion of a PG&E gas line in San Bruno, Calif., in 2010. (See [CPUC Expands Probe into PG&E Practices After Deadly Fire.](#))

On Thursday, the company asked the PUC to approve a \$1.1 billion rate hike to help pay for those additions and other upgrades as part of its [2020 General Rate Case](#) before the commission.

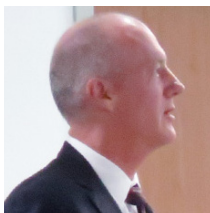


CAISO's Board of Governors met Thursday in Folsom, Calif., to vote on the 2019 budget and to hear updates on next year's policy initiatives. | © RTO Insider

CAISO's telecommunication, outsourcing and contract costs also will increase in 2019 because of the RC transition, Gordon told the board.

Another cost driver is the expansion of the EIM, with new entities joining the market and increasing administrative expenses, Gordon said. Powerex and Idaho Power began trading in the EIM this year, and the Sacramento Municipal Utility District will join in April 2019, she noted.

(See [Idaho, Powerex Began Trading in Western EIM.](#))



Greg Cook | © RTO Insider

The board unanimously passed the ISO's 2019 budget proposal. It also heard about 2019's policy initiatives from Greg Cook, CAISO's director of market and infrastructure policy.

A major effort involves proposed changes to the day-ahead market, including 15-minute scheduling and flexible ramping.

"We're looking at significant enhancements to our day-ahead markets," Cook said.

CAISO Governor Angelina Galiteva asked Cook whether ISO staff were aligning their

policy initiatives with outside developments, particularly California's adoption of a rule requiring all new homes to have rooftop solar panels starting in 2020. The state Building Standards Commission approved the rule, the first of its kind in the U.S., on Dec. 5.

"It may catch up with us before we even know what's going on," Galiteva said.

In addition to solar panels, many households will eventually get in-home electricity storage units for the power they produce, she said. "My sense is people are going to start installing storage and a lot of it," she said.

Berberich responded, "Governor, I think you're probably appropriately worried." He said behind-the-meter storage, linked to home solar panels, would complicate CAISO's forecasting.

"Storage is going to be the biggest issue for us to sort out," the CEO said. Policies may be needed to govern the charging and discharging of storage units, including financial incentives for homeowners, he said.

"I'm not suggesting we send real-time prices to retail customers," he said. "I'm not sure that works."

But policymakers may need to "signal to the retail level as best we can," he said. "Then you can shape the behavior and usage. ■"

Continued from page 5

"PG&E is asking for a \$1.1 billion increase over currently adopted revenues for 2019" (\$8.506 billion), the company said on its website. "More than half of PG&E's proposed increase would be directly related to wildfire prevention, risk reduction and additional safety enhancements."

Part of its Community Wildfire Safety Plan, the changes would include installing stronger poles and covered power lines across 2,000 miles of high-risk fire areas.

"As noted, this rate case calls for \$1.1 billion in 2020, \$454 million in 2021 and \$486 million in 2022, respectively, to capture inflation and other cost escalation," PG&E wrote. "If approved by the CPUC, this proposal would increase a typical residential customer bill by 6.4% or \$10.57/month (\$8.73 for electric service and \$1.84 for gas service)."

The proposal doesn't cover potential liability for the wine country fires or the Camp Fire, PG&E said. ■

CAISO/WECC NEWS



CAISO Q4 CRR Revenues Falling Short After Summer Surplus

By Hudson Sangree

FOLSOM, Calif. — CAISO’s efforts to rein in congestion revenue rights insufficiencies seemed to show progress this summer and early fall but fell short in the last months of 2018, the ISO reported Dec. 11 during its quarterly Market Performance and Planning Forum.

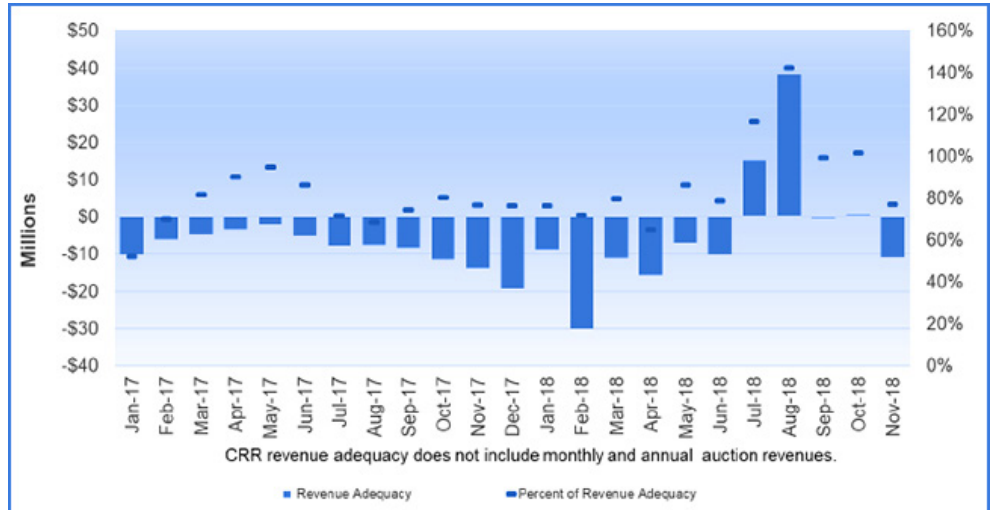
Historically CRR revenues have been inadequate to meet payouts, Guillermo Bautista Alderete, CAISO’s director of market analysis and forecasting, told meeting attendees at ISO headquarters.

That changed in the middle of this year because of high levels of summer congestion, he said.

“From July to October we actually flipped the condition, especially in July and August,” when there were significant surpluses, Bautista Alderete said. A graph he displayed showed a surplus in July of about \$15 million and close to \$40 million in August, which amounted to about 140% of revenue adequacy. Those figures did not include auction revenues.

The good news turned grim in November, when “we had insufficiency in the range of 80%,” he said. “Even if we account for auction revenues, we were still marginally short.”

The chronic shortfall in CRR revenues, leaving ratepayers footing the bill, has been an ongoing problem for CAISO. This year the ISO sought FERC’s approval for changes it hoped would help in 2019, but the commission was



The congestion revenue rights market saw an inadequacy in November compared to surpluses this summer, CAISO said. | CAISO

loath to give it everything it wanted.

In September, FERC rejected a CAISO plan to eliminate full funding of CRRs and instead scale payouts to align with revenue collected through the day-ahead market and congestion charges. (See [FERC Rejects CAISO Congestion Revenue Scaling Plan](#).)

In October, the ISO asked FERC for expedited review of a [revised proposal](#) to protect electricity ratepayers from funding shortfalls. (See [CAISO Modifies CRR Plan, Seeks Quick Approval](#).)

CAISO noted in its filing that CRR revenue shortfalls have continued into this year, and it urged the commission to quickly approve the

revised plan to relieve ratepayers from paying costs for fully funding CRRs in 2019.

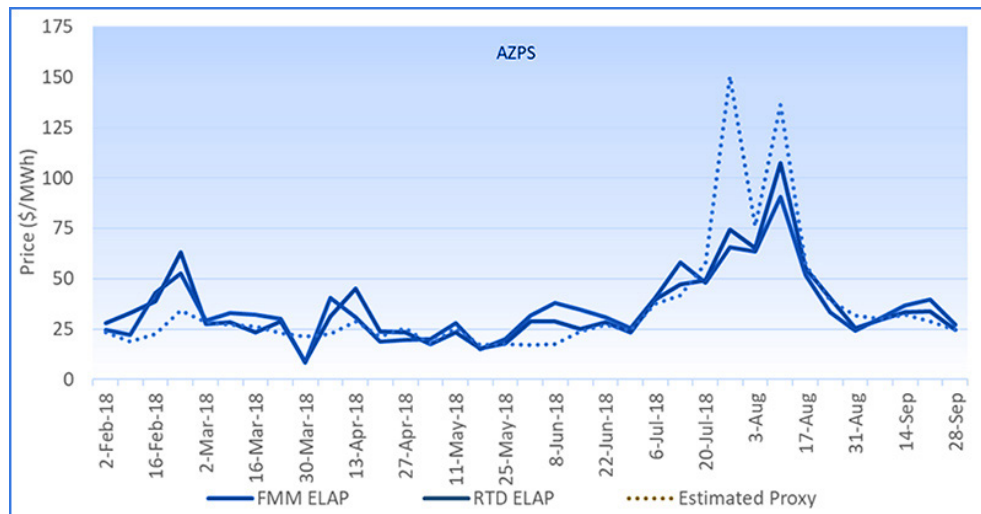
The ISO’s Department of Market Monitoring has estimated that CRR revenue shortfalls, which are allocated based on power consumption, cost California ratepayers about \$100 million a year.

In November, FERC accepted CAISO’s revised proposal, providing for CRR holders to be paid for their entitlements “only to the extent the CAISO collects sufficient revenue through day-ahead market congestion revenues and other sources to fund those entitlements,” the commission said. (See [FERC OKs CAISO Plan to Deal with CRR Shortfalls](#).)

“We agree with CAISO that the proposal reasonably distributes the burden resulting from congestion revenue insufficiency and will help improve the revenue insufficiency and auction revenue shortfall,” FERC said. “Rather than relying solely on [load-serving entities] to make whole CRR holders in the event those obligations are revenue insufficient, CAISO’s proposal distributes the burden to all CRR holders.”

Other results reported at last week’s meeting included a stabilization in Western Energy Imbalance Market prices after a big spike at the end of July caused by high summer demand.

“As we have passed those summer months, the prices are generally stable,” Rahul Kalaskar, CAISO manager of market validation analysis, told those gathered and on the phone. ■



EIM prices were stable in the fourth quarter after spikes over the summer. | CAISO



ERCOT Board of Directors/Annual Meeting Briefs

Staff Revisiting 2018 Playbook in Planning for 2019's Slim Reserve Margins

AUSTIN, Texas — ERCOT is repeating many of the preparations it took before last summer — and adding others — as it looks ahead to even tighter reserve margins in 2019.

CEO Bill Magness told the Board of Directors on Dec. 11 that meetings have already begun with stakeholders as the grid operator begins preparations to take on summer load with an 8.1% reserve margin. Staff and stakeholders collaborated similarly last year to minimize generation downtime and ensure the availability of resources during the high-demand periods.

ERCOT's 2017 year-end capacity, demand and reserves [report](#) revealed a 9.3% reserve margin. A 525-MW increase in generation capacity helped improve that margin to 11% before the summer season began. The grid operator met 14 new demand peaks above the previous record without resorting to emergency measures.

"As we did last summer, and with tight reserves expected, we're going in and talking with all of you ... on the things we can be doing and the things we can be doing together to make sure that we're ready for a tight summer," Magness said.

DeAnn Walker, chair of the Texas Public Utility Commission, has already coordinated meetings between the electric sector and gas pipelines.

Separately, ERCOT has made distributed energy resources and switchable units — interconnected to other regions but available to ERCOT — a point of emphasis. The board's recently approved Nodal Protocol revision request ([NPRR869](#)) requires certain behind-the-meter generators over 1 MW to provide modeling information. Staff has also been working to clarify operating agreements with SPP and MISO over the use of switchable units.

"It's incredibly important that your model reflect what is on your system when you have tight conditions, and you really need to know what to expect," Magness said.

Another measure, [NPRR901](#), part of the board's consent agenda last week, adds a new resource status code for switchable resour-



Board Chair Craven Crowell opens ERCOT's annual meeting. | © RTO Insider

es operating in a non-ERCOT control area. Magness said a staff proposal, [NPRR912](#), which is currently before the Protocol Revision Subcommittee, "will address the compensation issue for when units move back and forth."

"That discussion has begun," Magness said.

Addressing the shrinking reserve margin, Magness said there were no major retirements akin to 2017's 4-GW loss of coal-fired capacity. He said a change in the calculation of emergency response reserve service, capacity deratings and delayed renewable and gas projects accounted for 2.5 percentage points of the 2.9-point drop in the reserve margin.

A 564-MW increase in the load forecast for the Far West Texas weather zone, fueled by oil and gas production in the reserves-heavy Permian Basin, represented almost a percentage point decrease in the reserve margin.

The growth has been fueled by the Permian Basin's rich petroleum reserves, the largest in the U.S. Production has nearly doubled in the last three years, to 3.4 million barrels/day.

"We've been talking about Far West Texas load at every board meeting for at least a year, because we continue to see accelerating load growth in that area, an area with very little load until recently," Magness said.

He noted the board has approved transmission projects in recent years to meet the growing demand. (See [ERCOT Board Approves \\$53.3M Economic Tx Project](#), and "\$327M in Tx Projects will Meet Permian Basin's Load Growth," [ERCOT Board of Directors Briefs: June 12, 2018](#).)

Revenues Up

ERCOT is looking at a \$26.1 million favorable variance in net revenues, Magness said, mostly because of an \$11 million gain in interest income and a \$7.5 million jump in system administration fees.

"I wish I could credit that to our financial wizardry, but it is more that revenues have increased substantially over what was originally budgeted," Magness said.

Staff used an interest rate of about 0.37% when they drafted the biennial 2018-19 budget. Magness noted rates have increased to a "shocking" 1.73% since then.

"That's something, as we budget for 2020, we see ourselves correcting as we align that more with current interest rates," he said.

New World of Gas Prices for Market



Potomac Economics' Beth Garza | © RTO Insider

Beth Garza, executive director of ERCOT's Independent Market Monitor, warned stakeholders that the market is "heading into a very different natural gas world."

"We're starting to see some very different gas prices than we've seen the last few years," she said during her regular board [report](#).

The Monitor uses Houston Ship Channel prices as its underlying index price. Garza said

ERCOT NEWS



the index's November prices are at \$4.10/MMBtu after almost two years in the \$2/MMBtu range.

The increase in gas prices has resulted in an accompanying 24% increase in average real-time energy prices, to \$35.90/MWh through October. Prices were at \$29/MWh a year ago, on their way to finishing 2017 at \$28.30/MWh.

Forward prices for summer 2019 are also on the rise, Garza said, with \$173/MWh prices for August as of Nov. 23.

"That's not as high as we saw heading into July and August of last [summer], but we're in December," she said.

ERCOT Staff Share 5-Year Strategic Plan

Staff delivered an overview of the 2019-2023 [strategic plan](#), telling the board and stakeholders that ERCOT's leadership is setting up the organization to "quickly adapt to those changes that may come to us."



ERCOT's Kristi Hobbs |
© RTO Insider

"What we are required to do as an organization has not changed, but we must proactively change how we do things so that we can keep up with those things that are happening to us," said Kristi Hobbs, ERCOT's director of enterprise

risk management and strategic analysis, who led the team.

The team solicited feedback from 200 stakeholders in drafting a plan that lists four objectives:

- Enhancing operating capabilities to maintain reliability in an increasingly complex system;
- Improving information exchange to facilitate collaboration;
- Advancing competitive solutions to industry changes; and
- Optimizing the use of ERCOT resources to "continuously provide high-value services."

In an opening message, Magness wrote that there is no magic to the five-year time horizon, but that it "does require us to think far enough into the future to consider potential technological, economic and policy changes."

2019 Board Members, TAC Reps Approved

Members approved and confirmed directors



ERCOT CEO Bill Magness before the Board of Directors | © RTO Insider

and segment alternates to the board for 2019 during ERCOT's 48th Annual Membership Meeting.

Exelon's Bill Berg and Direct Energy's Ned Ross will join the board as segment alternates in the Independent Generator and Independent Retail Electric Provider segments, respectively. Berg replaces Luminant's Amanda Frazier, and Ross steps in for VEH's Mohsin Hassan.

Two board positions are vacant. The Consumer-Texas Office of Public Utility Counsel position is empty, following the recent departure of Tonya Baer, who has become the deputy director for the Texas Commission on Environmental Quality's Office of Air.

The board also has a vacancy in the Unaffiliated segment.

The board previously confirmed the Technical Advisory Committee's [members for 2019](#).

The TAC will welcome Brandon Whittle (Calpine), Marty Downey (Electranet Power) and David Kee (CPS Energy) as new members. They replace Thresa Allen (Avangrid Renewables), Read Comstock (Source Power & Gas) and John Bonnin (CPS), respectively.

TAC will hold its meetings on the fourth Wednesday of the month next year, a switch from Thursdays.

Board Approves Staff Recs, 31 Change Requests

The board unanimously approved ERCOT's key performance indicators for 2019 staff compensation and Schellman & Co.'s 2018 system and organization control audit report, which found no exceptions. It also approved

two TAC-endorsed staff recommendations: an increase from 5% to 7.5% of the boundary threshold used in calculating load forecasts for Far West Texas, and removing a 1,375-MW floor on non-spinning reserves, part of the annual review of ERCOT's methodology for determining ancillary service requirements. (See [ERCOT Technical Advisory Committee Briefs: Nov. 29, 2018](#).)

The board also unanimously passed a consent agenda that included 14 NPRRs, a Load Profiling Guide revision request (LPGRR), two changes to the Nodal Operating Guide (NOGRRs), three Other Binding Document revisions (OBDRRs), four changes to the Planning Guide (PGRRs), a Retail Market Guide change (RMGRR), two revisions to the Resource Registration Glossary (RRGRR) and a system change request (SCR):

- **NPRR878:** Emergency response service obligation report for transmission and/or distribution service providers.
- **NPRR879:** Security-constrained economic dispatch base point, base point deviation and performance evaluation changes for intermittent renewable resources (IRRs) that carry ancillary services.
- **NPRR881:** Reduces the residential validations requirements from an annual process to a triennial market event.
- **NPRR882:** Procedures for wind and solar equipment change. (Related to PGRR067.)
- **NPRR884:** Introduces systems changes needed to manage cases when ERCOT issues a reliability unit commitment instruction to a combined cycle resource that is already a qualified scheduling entity committed for an

ERCOT NEWS

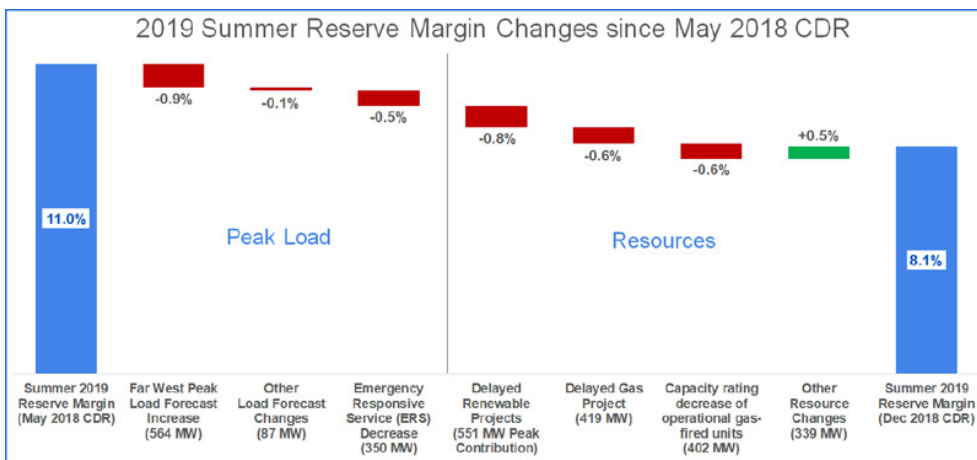


hour. The resource will operate in a configuration with greater capacity for that same hour.

- **NPRR887:** Creates a new market information system certified area posting that provides insight into the potential risk associated with each counterparty's default uplift charges.
- **NPRR892:** Places a \$75/MWh floor on energy for units carrying non-spinning reserve and responsive reserves and/or regulation up service concurrently to ensure the non-spin capacity is priced above the floor.
- **NPRR893:** Clarification of fuel index price and incorporation of systemwide offer cap and scarcity pricing mechanism *methodology* into protocols.
- **NPRR894:** Corrects the formula for allocating unaccounted for energy (UFE) to UFE categories by removing obsolete components.
- **NPRR895:** Removes the current exclusion for IRRs that are not wind-powered in calculating the real-time ancillary services imbalance payment or charge. Photovoltaic generation resources are currently excluded in both the methodology for implementing the operating reserve demand curve to calculate the real-time reserve price adder and the process for settling the real-time ancillary services imbalance payment or charge.
- **NPRR897:** Adjusts the black start service procurement and testing process timeline, adds a weather limitation disclosure form and aligns the load-carrying test procedure with actual practice.
- **NPRR898:** Allows the electronic return of ERCOT-polled settlement metering site certification documents to the transmission and/or distribution service provider.
- **NPRR899:** Creates a new process by which qualified market participants can opt out of receiving digital certificates and having to appoint a user security administrator (USA); clarifies ambiguous requirements certificate



Board Vice Chair Judy Walsh and Chair Craven Crowell | © RTO Insider



ERCOT

holders must meet to receive and continue to hold digital certificates; and clarifies that a USA may be responsible for managing access to certain ERCOT computer systems that do not require digital certificates.

- **NPRR901:** Proposes a new resource status code ("EMRSWGR") for switchable generation resources operating in a non-ERCOT control area to provide additional transparency for operations and reporting.
- **LPGRR065:** Related to NPRR881, this change reduces the residential validations requirements from an annual process to a triennial market event and removes unnecessary load profile model approval process language.
- **NOGRR178:** Clarifies language relating to automatic load shedding.
- **NOGRR182:** Harmonizes the transmission operator emergency operations plan submittals with *NERC reliability standard EOP-011-1* by clarifying that TOP plans should be received by Feb. 15 as part of the annual effort to review them within 30 days.
- **OBDRR006:** Aligns language with NPRR884's changes.
- **OBDRR007:** Changes the ORDC's methodology to consider curtailed PV resources in determining the ORDC price adders.
- **OBDRR009:** Revises the online and offline capacity reserves for ERCOT out-of-market actions related to DC ties.
- **PGRR065:** Documents and clarifies existing processes by including transmission project information and tracking report and data requirements.
- **PGRR066:** Creates an inactive status generation interconnection or change request (GINR) projects that won't be listed in ERCOT's monthly generation interconnection status report but will retain the interconnection request numbers. Also defines a process that can be used to cancel interconnection requests that have failed to meet requirements.
- **PGRR067:** Describes how wind and solar facility equipment changes are treated throughout the generation interconnection process and clarifies language for GINR-related fees.
- **PGRR068:** Lays out the process for adding a DC tie to ERCOT's planning models and associated requirements; related to the Texas PUC's directive to determine how to model the proposed Southern Cross DC tie in its planning cases (Project **46304**). (See "Staff's Determination on DC Tie Flows, Pricing Gets OK," *ERCOT Board of Directors Briefs: Oct. 9, 2018*.)
- **RMGRR155:** Related to NPRR889, the change uses the new term, settlement-only distribution generator (SOG), to replace references to non-modeled generator and registered distributed generation.
- **RRGRR018:** Also related to NPRR889, uses the SOG term to replace glossary references to non-modeled generator.
- **RRGRR019:** Adds a modeling designation for switchable generation resources (SWGRs) to the resource asset registration form, indicating that SWGRs can potentially operate in another control area.
- **SCR797:** Allows ERCOT to automatically share current operating plans with a transmission service provider upon request by that provider. ■

— Tom Kleckner

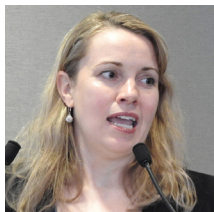
ISO-NE NEWS



New England Talks Solar, Storage and Public Policy

By Michael Kuser

BOSTON — Growing solar generation will be able to meet a third of peak load in Massachusetts in a few years, but as the grid is reaching the saturation point in certain areas, policy-makers are looking to energy storage to help address some of the challenges.



Judith Judson | © RTO Insider

“The grid was not initially designed for this much distributed energy ... and we never envisioned 90,000 power plants out there,” Commissioner Judith Judson of the Massachusetts Department of Energy Resources said Friday at the 160th

New England Electricity Restructuring Roundtable run by Raab Associates.

Judson *said* the state now has more than 89,000 installed solar projects totaling more than 2,300 MW in each of its 351 cities and towns.

On Nov. 26, it launched the Solar Massachusetts Renewable Target (SMART) program, which provides incentives for projects on brownfields, landfills, parking lots and rooftops. “SMART provides a fixed revenue stream to reduce the cost of the program, and we are the first state in the nation to have a solar-plus-storage incentive,” Judson said.

It took the state a long time to launch the program because “we have a regulatory process in DOER and in the Department of Public Utilities, plus heavy stakeholder engagement,” Judson said. “But we’ve had over 2,850 applications for 650 MW in capacity submitted so far and \$4.7 billion in cost savings to ratepayers compared to earlier solar programs, so I think it’s made for a better program.”

On Dec. 12, the state issued its Comprehensive Energy Plan (CEP), including a provision for the state’s utilities to procure a combined 200 MWh of energy storage by 2020. (See [Massachusetts Deploys Utility-Scale Energy Storage](#).)

Transition in Connecticut

“The grid modernization proceeding [Case 17-2-03] in Connecticut is a really promising opportunity,” said Mary Sotos, deputy commissioner of the state’s Department of Energy



The 160th New England Electricity Restructuring Roundtable drew a standing-room-only crowd in Boston on Dec. 14. | © RTO Insider



Mary Sotos | © RTO Insider

and Environmental Protection.

“I think it’s the first time utilities have laid out for the public ... how they’re doing manual, back-end system work for stuff they want automated at scale,” Sotos said. “It’s not just

the cost of the meters for them; the concern is managing the data ... putting it in the right format, which is all part of this broader shift in information availability.” (See [Connecticut Explores its Energy Future at CPES Event](#).)

Sotos highlighted “opportunities to align policy objectives, customer objectives and developer objectives.”

Connecticut’s solar programs are all in transition, including ones that limit virtual net metering for state, municipal and aggregation customers by capping the amount that could be reflected into rates, she said.

Connecticut last spring passed a bill that doubles the amount of renewable energy utilities must use to serve load — 40% by 2030 — while also revoking net metering guarantees that ensured rooftop solar owners earn retail prices for their excess electricity. (See [Connecticut Energy Bill Draws Mixed Reviews](#).)

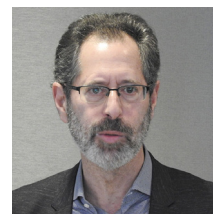
“Net metering was available to all these customers in the past on the energy side to compensate solar energy ... and each of those solar

programs had a statutory spending cap, but we found that municipalities were reaching that cap very quickly,” Sotos said. “For each of these groups we also had a separate program to help facilitate the deployment of behind-the-meter solar by focusing on the RECs [renewable energy credits].”

The state’s Green Bank ran “an incredibly successful” residential solar investment program to focus on the RECs from installations with storage, she said.

“However, under the current monthly net metering model, there isn’t an obvious incentive for customers to do storage, because any energy that is excess or used in real time, it’s all valued at the same level,” Sotos said. “From our perspective, to really value storage for dynamic peak reduction or other benefits ... there needs to be an additional financial signal, whether that’s a time-of-use rate or some other type of adder.”

Field Experience



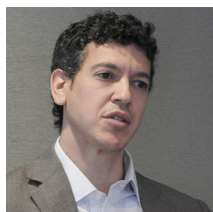
Jonathan Raab | © RTO Insider

Jonathan Raab of Raab Associates, who has been convening the roundtables since 1995, said he was lucky in his selection of two of last week’s panelists: Evan Dube, senior director of policy at SunRun, represented the most megawatts bid in the under-25-kW category in the SMART

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Evan Dube | © RTO Insider

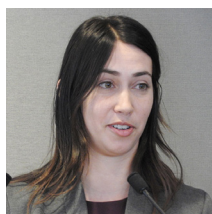


Ilan Gutherz | © RTO Insider

transmission investment,” Gutherz said.

New York’s Value of DER tariff that large-scale solar and other resources are now on has been testing value-based compensation as opposed to cost-based compensation alone, he said.

“New York’s an interesting experiment; in our opinion, they went a little bit too fast, so if you watch the recent filings from the commission there, you’ll see there’s been a lot of back-pedaling on certain aspects of that tariff,” Gutherz said.



Juliana Mandell | © RTO Insider

“Solar plus storage is a game-changer,” said Juliana Mandell, director of market development and policy at ENGIE Storage. “You’re transforming solar into a dispatchable, reliable renewable energy resource that’s no longer time-constrained, and that fundamentally shifts the conversation.”

Energy storage can flatten load and generation, be used to reduce peak demand, or to shift generation and load depending on grid system needs and economic signals, she said.

“And you can use storage to mitigate locational constraints and congestion [and] improve capacity supply, and storage can participate at a high level in the wholesale market,” Mandell said. “You can see that coming out of the recent FERC orders if you’re looking [at] how do we pay fairly for resources that provide a

different level of performance.”

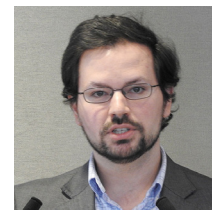


Jesse Jenkins | © RTO Insider

“The questions is not why solar, but why distributed solar?” said Jesse Jenkins, postdoctoral fellow at Harvard’s Kennedy School and one of the contributors to the MIT Utility of the Future study.

“Solar and storage are technologies and means that deliver value, so what we need to focus on is the ends that we have in mind and the value that we want to capture. ... Solar and storage are not the only ways to deliver any of the values we’re talking about.”

Mark LeBel, an attorney with Acadia Center, said that solar, peaking in summer, has to be balanced with winter-peaking wind, but that balance is also needed to value societal concerns.



Mark LeBel | © RTO Insider

Rooftops almost certainly have to be part of the answer for solar, because there are little or no siting issues, he said.

“Where are we going to put 20 GW of solar?” LeBel said. “Does New England want to pave over paradise?” ■

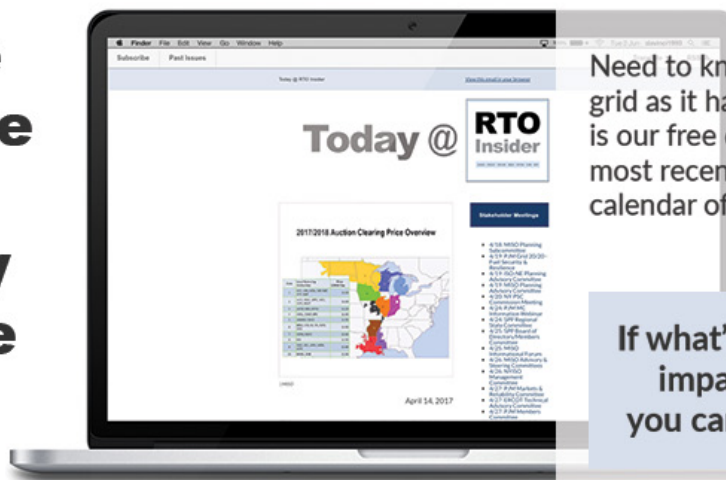
program, while Ilan Gutherz, senior director of strategy and policy at Borrego Solar, represented the most megawatts bid in the over-25-KW category.

“Having a robust [distributed energy resources] market, both behind-the-meter and in front, is going to be critical for sustaining the grid in the future,” Dube said. “We hear an awful lot about how rate design must be sustainable ... but in so doing, we have to keep in mind the benefits that building out these resources will have in the long term, and how that’s going to make us more sustainable in the future.”

More granular rate design such as time-of-use rates is preferable because it is fairer to customers, but that rate structure is contingent on penetration levels and their location, which affect the price of electricity, Dube said. The availability of metering infrastructure and data also influence how exact electric power billing can get.

The future of compensation for zero-marginal-cost resources like wind and solar depends on getting regulators to “think about how PV and batteries can avoid the need for long-term

If You're not at the Table, You May be on the Menu



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Mass. Offshore Lease Auction Nets Record \$405 Million

Continued from page 1

offshore wind lease auction is completely unprecedented,” said Nancy Sopko, director of offshore wind for the American Wind Energy Association.

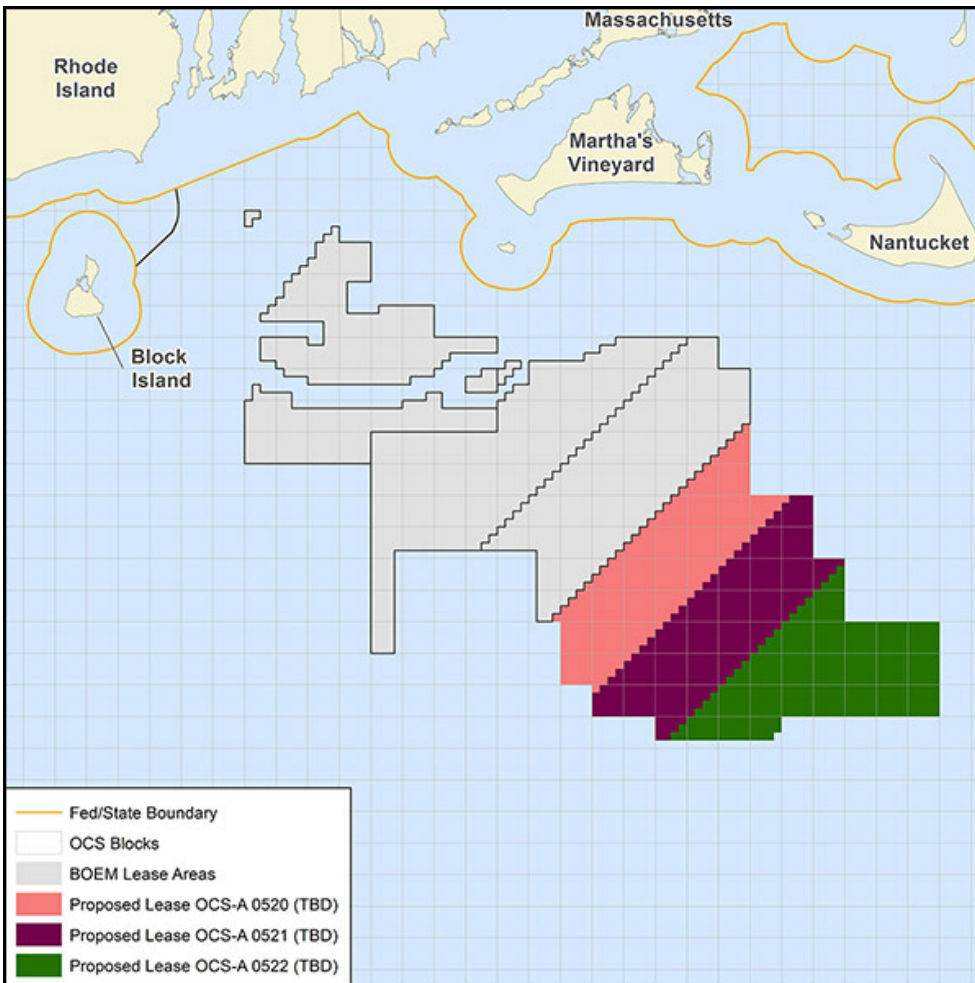
“To anyone who doubted that our ambitious vision for energy dominance would not include renewables, today we put that rumor to rest,” Interior Secretary Ryan Zinke said.

To illustrate the pace of the bidding, a BOEM [webpage](#) shows the winning bids – each \$135 million – at more than 500 times the size of the opening bids, which started at less than \$260,000.

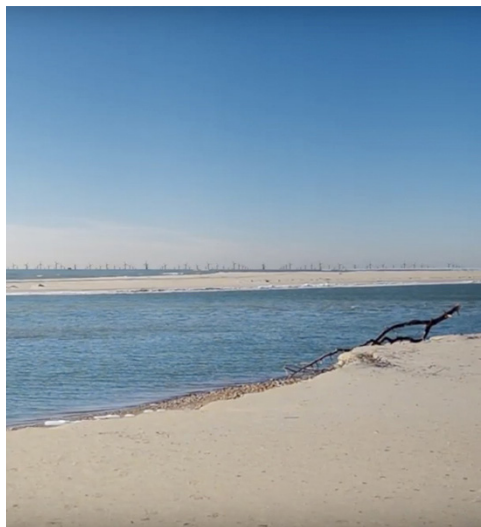
The new industry has gained momentum on the East Coast this year. Massachusetts and Rhode Island in May awarded 1,200 MW of offshore wind energy contracts. Vineyard Wind will supply Massachusetts with 800 MW, while Deepwater Wind won the contract to supply Rhode Island with 400 MW, which Connecticut expanded soon after with a 200-MW award. (See [Mass., R.I. Pick 1,200 MW in Offshore Wind Bids.](#))

New Jersey committed in May to build 3,500 MW, and New York in July authorized procurement of at least 800 MW or more in offshore wind energy, the first part of a two-phase plan to develop 2,400 MW by 2030.

The U.S. Department of Energy in June



BOEM map shows the leases won Dec. 14 by three developers: Equinor Wind US in pink; Mayflower Wind Energy in purple; and Vineyard Wind in green. | BOEM



A BOEM simulation of what the offshore wind turbines might look like from Wasque Point on Martha's Vineyard. | BOEM

awarded an \$18.5 million [grant](#) to the New York State Energy Research and Development Authority to lead a nationwide research and development consortium for the offshore wind industry, with the state to match the federal funds. (See [NYPSC: Offshore Wind 'Ready for Prime Time.'](#))

Massachusetts officials hope to develop supply chains for the nascent industry in the Port of New Bedford, where they have funded a terminal, but are also working to avoid interfering with fishing operations there, the No. 1 fishing port in the U.S. (See [Overheard at ISO-NE Consumer Liaison Group Meeting.](#))

BOEM said it now has 15 active wind leases for nearly 2 million acres in federal waters.

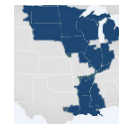
Before the Dec. 14 lease sale, the highest price for an offshore wind lease was slightly more

than \$42 million paid by Statoil two years ago for an area in the New York Bight. New York is expected to issue its first offshore request for proposals this month.

The U.S. Department of Justice and Federal Trade Commission will conduct a competitiveness review of the auction, and the provisional winner will be required to pay the winning bid and provide financial assurance to BOEM.

Upon BOEM approval of a site assessment plan in a lease's first year, the developer then has four and a half years to submit a construction and operations plan (COP).

After the bureau receives a COP, it will conduct an environmental review, with public input, and if BOEM approves the plan, the developer will then have 33 years to build and operate its project. ■



MISO to Evaluate Storage in Transmission Planning

By Amanda Durish Cook



Edin Habibovic | © RTO Insider

CARMEL, Ind. — MISO officials are still hashing out how they can best model and analyze energy storage-as-transmission in the RTO's transmission planning process.

During a Dec. 10 Reliability Subcommittee

meeting, MISO Senior Manager of Expansion Planning Edin Habibovic said planning for storage-as-transmission boils down to four key modeling factors:

- Determining the voltage, thermal or stability need;
- Asking if storage is the most effective, efficient and economical solution;
- Examining what level of megawatt or megavolt-amperes of injection is needed to resolve the issue; and
- Investigating how long the reliability issue usually lasts.

Habibovic said MISO also must study how frequently a storage asset would have to operate to resolve a reliability issue and how that cycling may impact the operational life of the asset. He also said MISO will need to look into seasonal load levels to estimate how often the asset may be dispatched in scenarios under the RTO's annual Transmis-

sion Expansion Plan (MTEP).

Storage solutions would also be evaluated to make sure charging and discharging don't cause harm either to the MISO transmission system or to generation projects in the definitive planning phase in the interconnection queue, Habibovic said.

"Just like any other reliability project, it can't solve one problem and cause another," he said.

But storage could be dispatched to minimize transmission system upgrade needs from generation projects in the definitive planning phase of the interconnection queue, he said. The result would be more flexibility in modeling the definitive planning phase.

WPPI Energy's Steve Leovy asked if MISO would employ a storage-as-a-transmission-asset (SATA) study process on solutions submitted for MTEP 19. Habibovic said MISO would study storage projects and might provide additional MISO assessments and discussions about the study results and feasibility of such projects. MISO already has at least one proposed storage project lined up for study under Appendix A of MTEP 19.

So far, MISO is only proposing a model for storage to act as a transmission reliability solution, solving thermal, voltage or stability issues. The RTO is leaving more complex SATA issues for later rules. (See [Few Clear Lines in MISO Storage as Tx Plan.](#))

MISO is accepting stakeholder comment on the challenges and benefits of incorporating

transmission-level storage in reliability planning through Jan. 7.

Inverter Projects to Prove Stability

MISO has added an option for owners of inverter-based generation to prove the system won't suffer degraded reliability because of their projects.

MISO in October said it was mulling requiring owners of inverter-based resources to supply their short-circuit ratios at the point of interconnection before completing an application to enter the queue. (See [MISO Moving to Head off Inverter-based Instability.](#))

Interconnection customers with an inverter-based project can now demonstrate a stable interconnection later in the queue process using one of two demonstration methods.

According to MISO interconnection engineer Warren Hess, project owners can either submit an Electromagnetic Transients Program (EMTP) study report confirming stable operation or, by the first decision point about 120 days into the queue, submit a short-circuit ratio at the point of interconnection and a manufacturer's letter stating the equipment operates reliably.

As with the first proposal, any project owner unable to prove stable operation must either add equipment to raise the short-circuit ratio or reduce the size of the project.

MISO is accepting another round of feedback on the proposal through Jan. 2. ■

OMS Names New Executive Director

The Organization of MISO States announced Monday that its board of directors has promoted Marcus Hawkins to head the organization, replacing outgoing Executive Director Tanya Paslawski next year.

Hawkins, formerly an engineer with the Wisconsin Public Service Commission, joined OMS in 2016 as its director of member services and advocacy. (See [Former Wisconsin PSC Engineer Marcus Hawkins Joins OMS Staff.](#))

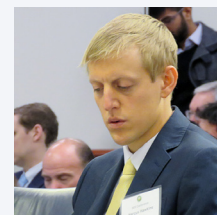
Paslawski, who has headed OMS since 2015, will leave effective Dec. 31 to become president of the Michigan Gas and Electric Association. (See [OMS Executive Director to Exit.](#))

"OMS commissioners know and have great respect for Marcus Hawkins' work as OMS director of member services and advocacy. We

look forward to working with him in his new role," said OMS board President Ted Thomas, chairman of the Arkansas Public Service Commission.

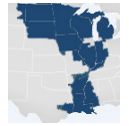
Hawkins said he is excited to lead OMS during "rapid change in the electric industry."

In addition to his role at the Wisconsin PSC, Hawkins has also worked at Wisconsin Energy Conservation Corp. and PA Consulting Group. Hawkins has a master's in mechanical engineering and a bachelor's in nuclear engineering, both from the University of Wisconsin-Madison. ■



Marcus Hawkins | © RTO Insider

— Amanda Durish Cook



MISO to Continue Resource Adequacy Talks in 2019

By Amanda Durish Cook

MISO will enter discussions with stakeholders in 2019 on long-term fixes to improve resource availability.

RTO staff said last week that the Resource Adequacy Subcommittee will focus on improvements to the Planning Resource Auction, loss-of-load expectation (LOLE) study and resource accreditation, including the possibility of seasonal resources. Since 2017, resource availability and need solutions have been discussed only in the Reliability Subcommittee. Now, MISO is ready for the RASC's ideas on increasing generator availability as the baseload fleet ages and more renewable resources come online.

The discussions will be aimed at making available resources in addition to the 5 to 10 GW of supply MISO hopes to free up with a trio of near-term FERC filings.

Speaking during a Dec. 13 RASC conference call, MISO Director of Resource Adequacy Coordination Laura Rauch said the RTO and stakeholders may examine how it calculates the planning reserve margin. Stakeholders asked if MISO would consider using something other than the summertime peak for the annual LOLE study, as the most recent emergencies and maximum generation events have occurred in shoulder months.

"That's a good point. ... We're starting to see these max gen emergencies in non-peak time frames. What changes could we make to inputs to the PRA and the LOLE study to mitigate those risks?" MISO planning adviser Davey Lopez asked stakeholders.

Lopez said MISO will begin talking about improvements to the LOLE study next month. He said any changes to the study need to take place before June 2019, when the study kicks off for the 2020/21 PRA.

RASC Chair Chris Plante said MISO may need to coordinate discussion between the RASC and the LOLE Working Group — charged with reviewing and recommending changes to the LOLE study methodology — so stakeholders don't suggest infeasible changes to the LOLE study process.

Customized Energy Solutions' Ted Kuhn said MISO should issue a report that shows when it has fallen below 10 GW in reserves during recent emergencies, saying it would help stake-



Laura Rauch | © RTO Insider

holders make suggestions for longer-term Tariff filings.

Lopez asked for stakeholder feedback and suggested adjustments to LOLE studies, capacity accreditation and PRA structure by Jan. 4.

MISO staff asked stakeholders to comment on changing the modeling of outages in LOLE studies, the modeling and accreditation of LMRs in the PRA, and whether the RTO should validate generator submissions to the Generating Availability Data System.

Near-term Filings

Talk also turned to MISO's three near-term filings.

Earlier in December, stakeholders criticized MISO's short-term solutions, which include requiring more data from certain load-modifying resources (LMRs) and imposing stricter notification times for planned outages. (See [MISO, Stakeholders at Odds over Resource Availability Filings](#).) MISO's LMR and outage filings are aimed at obtaining an additional 5 to 10 GW in resources during the spring maintenance season. MISO expects a large spring

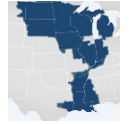
maintenance season and [said](#) that available spots for planned outages are going fast.

In all, MISO will make three Tariff filings aimed at short-term fixes: for demand response capability testing, LMR seasonal availability documentation and a new 120-day notice time for planned outages.

Rauch said some stakeholders have balked at MISO's 120-day requirement, which would prohibit scheduling changes unless they don't pose increased reliability risks. As a result, Rauch said MISO will defer the outage filing until no later than Jan. 31, still in time for a transition to the new rules in spring. The other two filings are expected to be submitted to FERC this week.

But Consumers Energy's Jeff Beattie said the LMR filing still needs work. He said while MISO is proposing a two-year transition period for new testing for LMRs operating under non-retail tariff contracts, the RTO should also allow the same two years for Public Utility Regulatory Policies Act contracts. He said such PURPA contracts should be held harmless from the new rules until they expire. Staff said they would consider the request. ■

MISO NEWS



MISO Prepping for Growth in Dynamic Line Ratings

By Amanda Durish Cook

MISO staff are considering how to respond to transmission owners' adoption of dynamic line ratings, acknowledging that changes in systems and operations would likely be necessary with widespread use.

Acting on a recommendation from the RTO's Independent Market Monitor, staff broached the topic with a [presentation](#) during a Dec. 13 conference call of the Market Subcommittee.

Operations engineering manager Jay Dondeti said MISO already allows TOs to submit dynamic line ratings, though most don't. Dynamic line rating technology provides real-time data on environmental conditions near transmission lines, including ambient temperature, solar radiation and wind speed, allowing lines more capacity in cooler conditions.

Currently, TOs can provide line ratings to MISO through one of four ways: a seasonal ratings table with ratings for up to four seasons; a ratings lookup table based on temperatures; supplying specific ratings through the Inter-Control Center Communications Protocol; and submitting hourly and current day ratings through direct data files.

MISO staff and systems would not be able to process dynamic line ratings if every TO in its network decided to use them, and it's unclear how much dynamic data the RTO can handle.

Widespread use is a long way off. Dondeti said about 93% of MISO TOs currently use seasonal ratings, with the "vast majority" of them providing ratings for two seasons, not four. He said less than 1% of line segments in the Midwest use some form of temperature-based ratings. In MISO South, however — where Entergy has adopted some temperature-based ratings using the filing approach — the percentage goes up to 5%.

Some stakeholders are echoing the Monitor's calls to adopt dynamic line ratings. (See "Dynamic Line Ratings," [MISO Market Subcommittee Briefs: Oct. 11, 2018](#).)

"We see the transmission system as underutilized in the day-ahead and real-time markets because of static line ratings," WEC Energy Group's Chris Plante said.

Kevin Murray, representing the Coalition of MISO Transmission Customers, said dynamic line ratings might have helped the RTO mitigate some of its recent maximum generation events by transporting additional capacity

stranded by static line ratings.

Entergy's Mark McCulla [said](#) his company provides temperature-adjusted line ratings using historical and forecasted weather conditions near a facility to help increase the carrying capability of static line ratings. The company does not factor wind speeds into its more detailed ratings, instead using a 2-feet/second estimate. Entergy provides dynamic ratings to MISO on an hourly, daily and two-day-ahead basis.

"There can be a large swing in ambient temperatures in the Entergy region regardless of season. As a result, Entergy does not use seasonal ratings but instead uses the more granular temperature-adjusted ratings," McCulla said.

Of Entergy's more than 2,300 69-kV and above transmission facilities, 978 are in Entergy's temperature-adjusted ratings database and 140 have short-term emergency ratings.

Entergy said it has experienced a 11% average increase over base facilities ratings when using temperature-adjusted ratings and a further 13% rating increase when coupled with short-term emergency ratings.

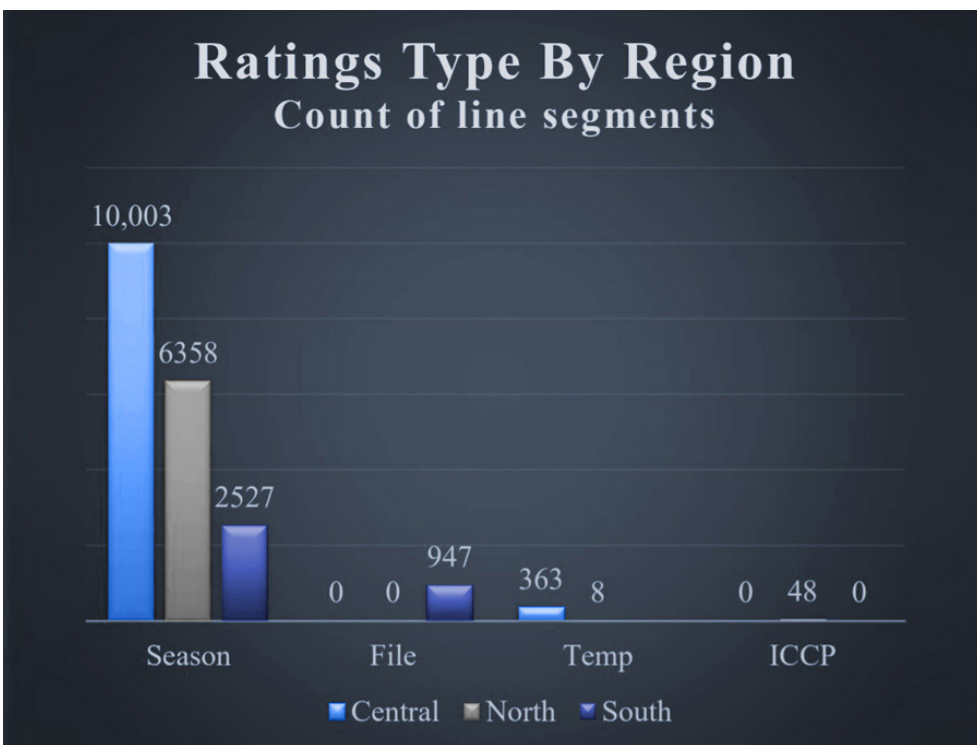
Plante asked if Entergy has experienced reliability risks since using the ratings. Entergy representatives said they have yet to experience an overload.

IMM staffer Michael Wander said the Monitor supports using temperature-adjusted ratings, saying MISO's static line ratings are often conservative.

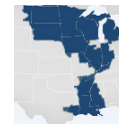
Wander agreed to appear at future MSC meetings to discuss the economic benefits of dynamic line ratings. He said the Monitor is not advocating a "one-size-fits-all" approach to ratings, but an RTO review process.

Dondeti said MISO will likely have to assess how it would handle the volume of ratings adjustments if dynamic line ratings become routine among TOs. He said it would need to figure out how often line ratings would be changed and how many staffers would need to process them.

RTO officials said they would report on the benefits and potential cost of processing dynamic line ratings in the first half of 2019. MSC Chair Megan Wisersky told stakeholders to expect discussion on the topic at upcoming subcommittee meetings. ■



MISO line ratings types | MISO



FERC Seeks More Details on Pleasant Prairie Recovery

By Amanda Durish Cook

FERC last week ordered a closer look into whether We Energies accurately estimated customer savings stemming from the retirement of the Pleasant Prairie coal plant in southeastern Wisconsin.

The commission's Dec. 11 ruling accepted, then suspended, We Energies subsidiary Wisconsin Electric Power Co.'s new wholesale tariff that includes the remaining costs on the plant, setting the rate for hearing and settlement judge procedures over the company's claims of ratepayer savings related to the shutdown ([ER19-103](#)).

We Energies in April permanently [closed](#) the 1,190-MW coal plant, which entered service in 1980.

At retirement, Pleasant Prairie had an unamortized plant balance of approximately \$665 million, which We Energies sought to amortize over about 23 years through an adjustment to its rate base. The company contended the recovery is just and reasonable, citing FERC's 1996 decision to allow Yankee Atomic Electric Co. to recover from ratepayers 100% of its remaining unamortized investment in its nuclear plant after a study showed the plant's operating costs exceeded the value of its output.

Between 2003 and 2007, We Energies invested \$365 million worth of capital, environmental and reliability investments into Pleasant Prairie, all which were approved by the Public Service Commission of Wisconsin.



Pleasant Prairie Power Plant | We Energies

"Although Pleasant Prairie has reliably served Wisconsin Electric's customers for nearly 38 years, its value to customers began to decrease significantly after 2008 due to a significant loss of industrial load following the recession in 2007-2008 and improvements in energy efficiency; declining energy prices in MISO as a result of increased competition from natural gas and renewable energy resources; and a corresponding reduction in Pleasant Prairie's dispatch in MISO markets," the company told FERC.

We Energies says Pleasant Prairie's retirement will save retail and wholesale customers anywhere from \$2 billion to \$3.2 billion.

But wholesale customer Great Lakes Utilities challenged the customer savings estimates, arguing that We Energies' assumptions of a hypothetical carbon tax imposed in 2028 and other pricey environmental regulations on the coal plant are "not sufficiently supported."

The commission agreed that the cost-savings assumptions could use more evaluation.

FERC said it "cannot determine on the record before us whether the third prong of the test set forth in Yankee Atomic has been satisfied such that there will be substantial savings for customers as a result of Pleasant Prairie's retirement."

In the Yankee Atomic decision, FERC said a 100% recovery of a prematurely retired plant's unamortized balance is warranted when three criteria are met: the investment and retirement decisions are prudent, the plant has already provided years of beneficial service to customers and the retirement results in "substantial cost savings to customers."

While FERC said We Energies demonstrated prudent investment and retirement decisions, and that Pleasant Prairie was beneficial to customers over its nearly four decades of reliable operation, it could not definitively answer without further proceedings whether the company would achieve substantial customer cost savings from retirement of the plant. ■



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NYPSC Expands Storage, Energy Efficiency Programs Targets 3,000 MW of Energy Storage by 2030

By Michael Kuser

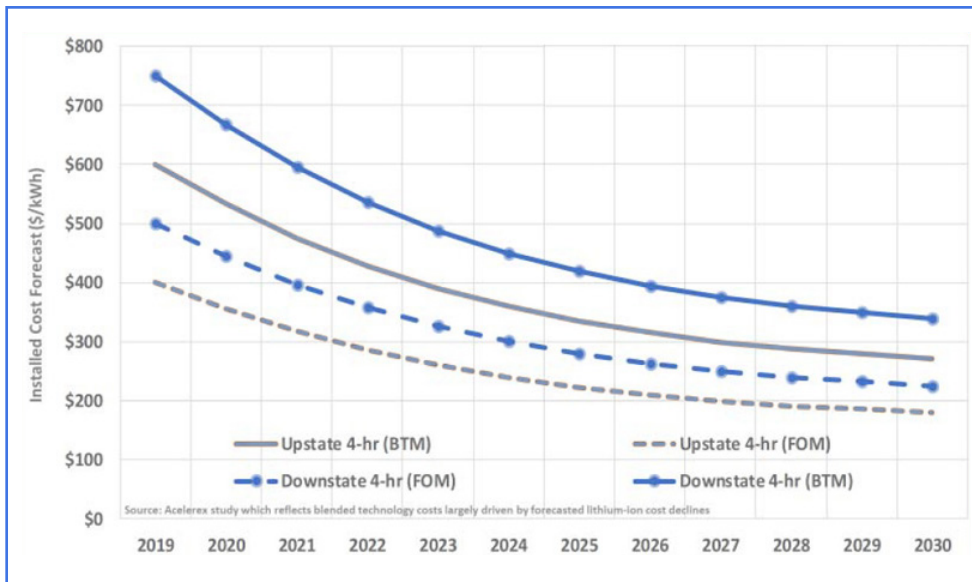
New York regulators on Thursday approved measures that will sharply increase the state's energy storage and efficiency targets.

The rulings by the Public Service Commission will double New York's existing 2025 storage goal to 3,000 MW by 2030 and require the state's utilities to reduce building energy use by an additional 31 trillion British thermal units (TBtu) to meet an energy efficiency target of 185 TBtu by 2025.

"As the federal government continues to ignore the real and imminent dangers of climate change, New York is aggressively pursuing clean energy alternatives to protect our environment and conserve resources," Gov. Andrew Cuomo said in a statement. "These unprecedented energy efficiency and energy storage targets will set a standard for the rest of the nation to follow, while supporting and creating jobs in these cutting-edge renewable industries."

The commission's Dec. 13 storage order (Case [18-E-0130](#)) accepted with modifications the state's six major utilities' proposed "hybrid tariff" for storage systems paired with eligible electric generating equipment, directing each utility to distinguish between renewable and non-renewable energy injected into the grid.

The PSC's March 2017 Value of Distributed Energy Resources Phase I order (Case



Blended energy storage cost forecasts for behind-the-meter storage site with load and front-of-the-meter storage connected at the distribution or bulk transmission level. | NYSERDA

[15-E-0751](#)) directed utilities to compensate distributed energy resources through the "value stack," a methodology that bases compensation on benefits provided. (See [NYPSC Adopts 'Value Stack' Rate Structure for DER.](#))

The investor-owned utilities (Central Hudson Gas & Electric, Consolidated Edison, New York State Electric and Gas, Niagara Mohawk Power, Orange and Rockland Utilities, and Rochester Gas and Electric) now must file

tariff amendments incorporating the value stack compensation for a hybrid facility and explaining how they will manage appropriate metering and controls under four potential usage models.

The commission said that "non-renewable energy is only eligible for compensation for energy value, demand reduction value, locational system relief value" and other capacity value, "while renewable energy is also eligible

NYISO Forecasts Adequate Capacity for Winter

By Michael Kuser

its forecasted peak demand of 24,269 MW for the 2018/19 winter season, well under last winter's peak of 25,081 MW.

The ISO expects capacity resources, including imports and demand response, to total 43,943 MW this winter, ISO Vice President of Market Operations Emilie Nelson said in a review of the winter outlook.

Installed generation amounts to 41,539 MW, while the ISO has acquired external capacity of 1,519 MW for the winter. Projected demand response resources equal 884 MW, Nelson said.

The ISO forecasts a capacity margin of 11,436 MW based on a 50/50 winter peak forecast with average winter weather conditions

NYISO said last week it will have adequate capacity on hand to meet

consisting of composite statewide temperatures of 15 degrees Fahrenheit. More extreme temperatures in the model (approximately 5 degrees statewide) result in a higher forecasted 90/10 peak load of 25,884 MW, with marginal capacity of 9,821 MW.

"Last winter's peak [on Jan. 5] occurred during a two-week cold snap, and the all-time winter peak of 25,738 MW occurred in January 2014, during what was called the polar vortex," Nelson said.

In response to the harsh winter five years ago, "we have fine-tuned many of the things we do in advance of the winter season," Nelson said. The ISO enhanced its winter reliability planning by providing stronger incentives for generators to secure fuel for winter peak demand needs and improved its monitoring of the natural gas system and checking of generator fuel inventories.

Continued on page 19

NYISO NEWS



for compensation for environmental value, a market transition credit if applicable to the project” and other capacity value.

Market Acceleration

The commission’s order also authorized \$310 million in market incentives to be administered by the New York Energy Research and Development Authority for pairing storage with solar projects, in addition to the \$40 million announced in November. The order also directs the utilities to hold competitive procurements for 350 MW of bulk-sited storage systems.

PSC Chair John B. Rhodes said, “Energy storage is the key to unlocking renewables and reducing bottlenecks and costs on the grid. Today’s orders ramp up New York’s commitment and achievement, delivering bill savings for all New Yorkers while driving down carbon emissions.”

NYSERDA and the state’s Department of Public Service developed the PSC-mandated energy efficiency targets (Case [18-M-0084](#)), which now include a 3% annual reduction in electricity sales by 2025 and 5 TBtu of savings from the installation of heat pumps, which help reduce emissions from the heating and cooling of buildings.

The commission also required that at least 20% of any additional public investment in energy efficiency go to help poor and middle-class New Yorkers gain access to renewable energy.

“New York’s clean energy industry welcomes today’s actions by the commission as important steps forward for energy storage and energy efficiency policy. Both are critical as



The PSC held its regular monthly session in New York City on Dec. 13, 2018.

New York continues its transition to a cleaner, more renewable and more efficient electricity system,” Anne Reynolds, executive director of the Alliance for Clean Energy New York, said in a statement.

In a separate ruling, the PSC approved Con

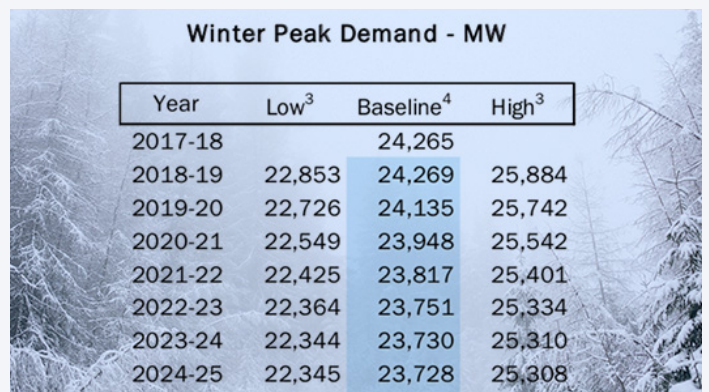
Ed’s pilot smart meter pricing program (Case [18-E-0397](#)) for customers in Staten Island, Westchester County and Brooklyn to be recruited by both opt-in and opt-out enrollment strategies and provided a one-year price guarantee. The program runs through March 2022. ■

Continued from page 18

“In preparing for the winter 2018/19, we start by conducting a generator fuel survey ... and also we like to understand any arrangements they have in place for replacement fuel,” Nelson said. “This is particularly important in New York, because so many of our generators are located along waterways that allow replenishment of fuel storage through the winter.”

When considering resupply, the focus is on oil, which is typically used as a backup fuel in New York, prompting the ISO to differentiate between resources with fuel tanks that will be drawn down throughout the season and those that can resupply from barges as needed, Nelson said.

In the spirit of testing for extremes, the ISO forecast models a loss of natural gas scenario, which is less about replenishment than demand coming from both homes and power generators, she said. ■



NYISO long-term winter forecast for 2018 to 2025, including transmission and distribution losses. The low and high forecasts are at the 10th and 90th percentiles for extreme weather conditions, respectively. | NYISO



NYISO Business Issues Committee Briefs

NYISO, PJM Win JOA Waiver Request

FERC last month granted NYISO and PJM a waiver of their joint operating agreement, allowing the two grid operators to add the East Towanda-Hillside tie line as a market-to-market flowgate ([ER18-2442](#)), Rana Mukerji, senior vice president for market structures, told the Business Issues Committee on Wednesday in presenting the monthly Broader Regional Markets [report](#).

The temporary waiver permits PJM to conduct redispatch operations to control flows to the more restrictive rating on the New York side of the line without violating its Tariff. (See “NYISO and PJM JOA Waiver Request,” [NYISO Business Issues Committee Briefs: Oct. 10, 2018](#).)

The commission’s ruling also required the grid operators “to submit quarterly reports regarding the status of JOA revisions to implement a long-term solution.”

Reference Level Manual Changes

The BIC approved changes to three sections of the Reference Level Manual to comply with FERC Order 831.

Mitigation References Supervisor Giacinto Pascazio [told](#) the BIC the sections dealt with fuel-cost adjustments (FCAs), FCAs with generator bids in excess of \$1,000/MWh and reference level development for demand-side resources.

The changes provide generators the ability to reflect updated fuel information to the ISO, which then automatically screens the FCA.

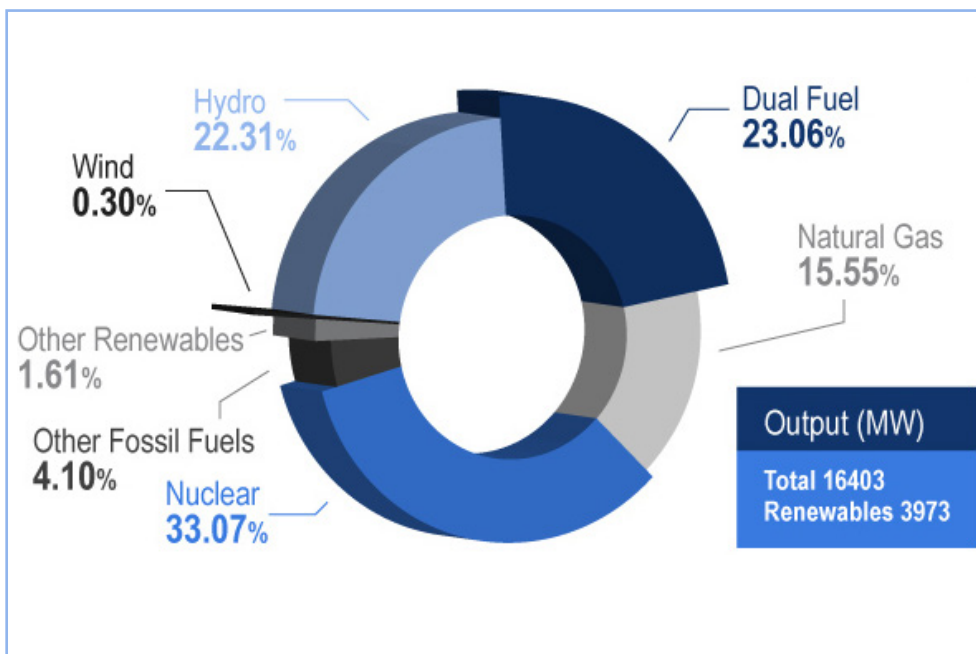
The ISO will reject energy offers above \$1,000/MWh that lack FCAs. The changes also establish an FCA process for generators that do not burn oil or natural gas.

Validated cost-based reference levels from \$1,000 to \$2,000/MWh will serve as the bid cap, and any demand-side resource wishing to bid in excess of \$1,000/MWh must initiate a consultation with the ISO 30 days prior to the start of the capability period.

A demand-side resource’s cost to reduce load should align with its discounted net revenues in the immediate future.

Real-time Market Settlements Clarifications

The BIC unanimously approved Tariff changes clarifying real-time market settlements and



The ISO’s real-time fuel mix chart shows the energy generated within New York state at mid-afternoon on Dec. 12, 2018. | © RTO Insider

their interaction with energy storage resources (ESRs). ISO staffer Christopher Brown [told](#) the BIC that the changes — which are subject to approval by the ISO’s Management Committee later this month and by the Board of Directors in January — do not affect calculations or require software modifications.

Energy imbalance payments and charges address the differences among actual energy injections or withdrawals and real-time and day-ahead energy schedules.

The changes apply to ESRs injections and withdrawals and include terms that were introduced and defined in the ISO’s FERC Order 841 compliance filing submitted Dec. 3 ([ER19-467](#)). (See [RTOs/ISOs File FERC Order 841 Compliance Plans](#).)

Natural Gas Prices Up 45% in November

NYISO [locational-based marginal prices](#) averaged \$43.15/MWh in November, up just over 20% from October and 52% from the same month a year ago, Mukerji said in his monthly operations [report](#). Day-ahead and real-time load-weighted LBMPs came in higher compared to October.

Year-to-date monthly energy prices averaged \$45.11/MWh in October, a 30% increase from a year ago. November’s average sendout was

411 GWh/day in November, compared with 399 GWh/day in October and 403 GWh/day a year earlier.

Transco Z6 hub natural gas prices averaged \$4.23/MMBtu for the month, an increase of 45.4% over October and 44.8% from a year ago.

Distillate prices dropped compared to the previous month but were up 9.3% year-over-year. Jet Kerosene Gulf Coast averaged \$14.50/MMBtu, down from \$16.65 in October. Ultra Low Sulfur No. 2 Diesel NY Harbor was down to \$14.72/MMBtu, from \$16.66 the previous month.

November uplift increased to -27 cents/MWh from -30 cents in October, while total uplift costs, including the ISO’s cost of operations, were -30 cents/MWh, lower than -11 cents in September.

The ISO’s 25-cents/MWh local reliability share in November dropped slightly from 27 cents the previous month, while the statewide share climbed from -56 cents/MWh to -52 cents.

The Thunderstorm Alert cost in New York City was \$0/MWh, compared to 75 cents/MWh in October. ■

— Michael Kuser



PJM Moving Quickly to Make Board's Price Formation Deadline

By Rory D. Sweeney

VALLEY FORGE, Pa. — PJM staff moved briskly through a dense agenda during Friday's meeting of the Energy Price Formation Senior Task Force (EPFSTF) in hopes of wrapping up the wide-ranging, yearlong initiative by a Jan. 31 deadline set last week by the Board of Managers.

The dramatic debates that often attend PJM stakeholder meetings were largely kept in check, although several stakeholders shared their reactions to the deadline at the meeting, the task force's first since the board published a letter issuing it.

The board said it saw need for six revisions to how the RTO forms prices in its energy market and that if stakeholders haven't endorsed plans to address the six needs by Jan. 31, it will direct PJM staff to unilaterally file a plan for FERC approval. (See [PJM Board Demands Action on Energy Price Formation](#).)

Susan Bruce, who represents the PJM Industrial Customer Coalition, said the board appeared to feel stakeholders weren't making progress on the issues, even though the RTO had recently made large-scale revisions to its proposal and stakeholders made it clear a vote was coming soon.

"I was left with the impression [from the letter] that stakeholders couldn't get their act together to get a vote," she said. "I'm concerned about the perception of the board about what was happening, which has been good work at the EPFSTF. ... I think it doesn't fully appreciate the work that been done."

PJM's Dave Anders assured attendees that the board was apprised of all of the task force's activity.

Other stakeholders expressed skepticism that the task force can comprehensively address the six revisions demanded, particularly because two of them have yet to receive any discussion.

Carl Johnson, who represents the PJM Public Power Coalition, said aligning market-based reserve products in day-ahead and real-time energy markets was "the one thing I said at the beginning that I wanted to come out of this process ... so that's great."

But a "piecemeal" approach of endorsing solutions for any of the six that stakeholders can



Energy Price Formation Senior Task Force | © RTO Insider

agree on — which the board indicated it would accept — "doesn't work," he added. "I do not see how we can pull all of this together. I think the time frame is pretty unrealistic."

However, staff were confident that the timing is achievable. PJM's Adam Keech said the other as-yet-unaddressed revision — increasing operating reserve demand curve (ORDC) penalty factors to ensure utilization of all supply prior to a reserve shortage — is a relatively "straightforward" extension of what's already been discussed.

Catherine Tyler with PJM's Independent Market Monitor questioned whether there is evidence for what the grid needs to respond to stress events like the polar vortex and bomb cyclone cold snaps.

Keech pointed to reports staff produced on the RTO's performance during both of those events.

"I don't agree with the statement that there's been no analysis on stressed system events," he said, adding that the board saw all the documentation it needed to see "to come to the conclusion they've come to."

Anders added that he's "absolutely sure" the board has reviewed those documents.

Gabel Associates' Mike Borgatti and Erik Heinle with the D.C. Office of the People's Counsel

struck more upbeat tones with their comments. Heinle was optimistic that the differing sides were not too far apart. Borgatti called the deadline "a healthy step in the process" as the sides may never get to agreement.

Any FERC filing would come after the board's next meeting, scheduled for Feb. 11.

PJM Proposal

Keech and PJM's Lisa Morelli described staff's [proposal](#) for the six revisions. Though stakeholders indicated concerns, staff continued to move through a [presentation](#) in an attempt to fully describe the plan, which was published on Dec. 11, six days after the board's letter and three days before the task force meeting.

PJM's Anthony Giacomoni also presented the [results](#) of an analysis that stakeholders requested at the task force's previous meeting. The study simulated energy, reserve and uplift impacts of including the regulation requirement in the ORDC, first using the current two-step curve and then the proposed reserve-market revisions. The study, which covered June 1, 2017, through May 31, 2018, found that, at its most extreme, net costs would be reduced by \$350 million, with a \$1.92 billion increase in energy and reserve market revenues offset by a \$1.5 billion cut in capacity market revenue and a \$770 million drop in retail rate costs to load. ■



Full PJM Study Makes Case for Fuel Security Payments

Continued from page 1

system is reliable today and will remain reliable in the future,” says the report, which was released Monday. “Key elements such as on-site fuel inventory, oil deliverability, availability of non-firm natural gas service, location of a pipeline disruption and pipeline configuration become increasingly important as the system comes under more stress. ... While there is no imminent threat, fuel security is an important component of reliability and resilience — especially if multiple risks come to fruition. The findings underscore the importance of PJM exploring proactive measures to value fuel security attributes, and PJM believes this is best done through competitive wholesale markets.”

Ott went to D.C. last month to begin the drumbeat for compensating generators on their “fuel security,” outlining proposals including valuing it in the capacity market or developing a winter reserve product in the energy market. (See *PJM Begins Campaign for ‘Fuel Security’ Payments.*)

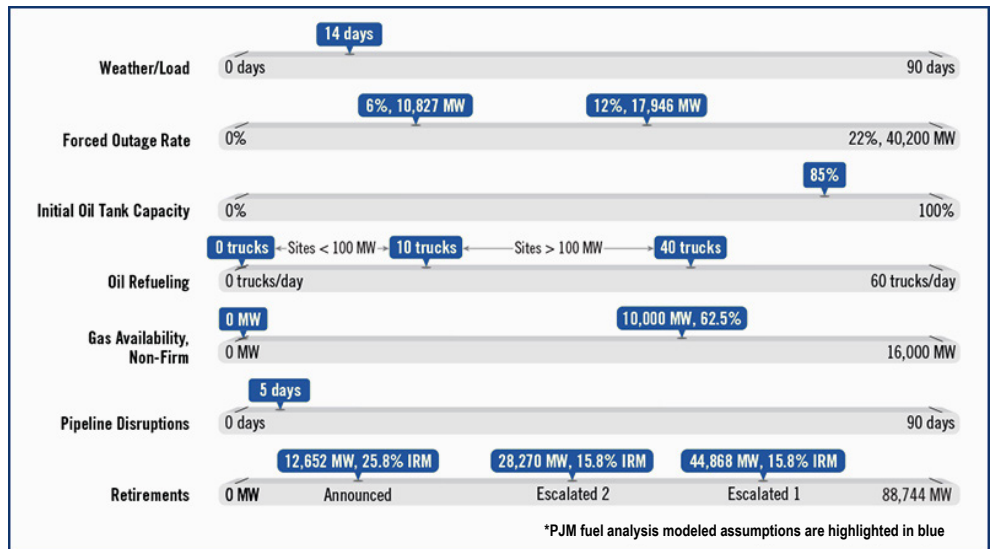
The study picks up where Ott left off, noting that the proposals have been submitted in the resilience docket FERC opened in January (AD18-7). (See *Don’t Rush on Resilience, Commenters Urge.*)

It says the results will be used to define and value “fuel security attributes” and describes the “key variables” to maintaining reliability during extreme events as:

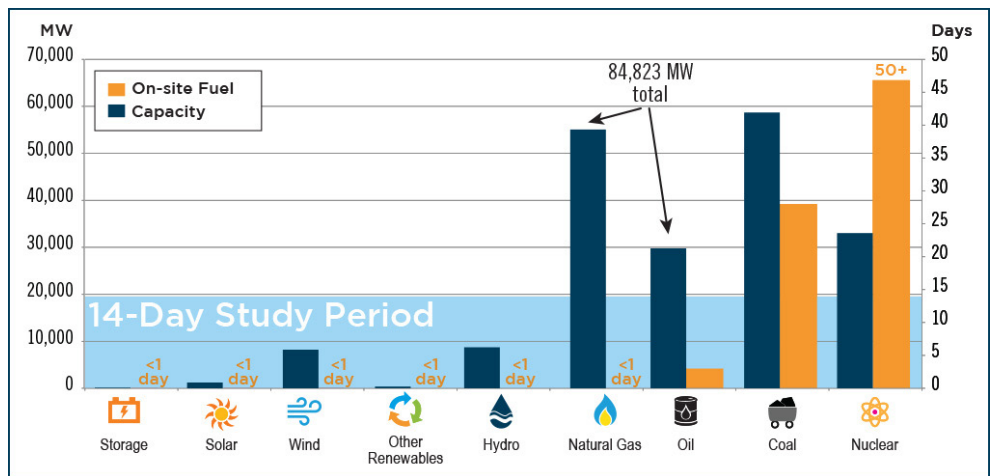
- Availability of non-firm gas transportation service;
- Ability of the fuel oil delivery system to replenish oil supplies during an extended period of extreme cold weather;
- Physical breaks at key locations on the pipeline system;
- Customer demand;
- Generator retirements, replacements and the resulting installed reserve margin (IRM);
- Use of operating procedures to conserve fuel during peak-winter conditions; and
- Pipeline configuration.

Study Details

The study focuses on natural gas- and oil-fired units that make up 84,823 MW of PJM’s capacity — about half of the total — but maintain



Ranges of assumptions | PJM



Fuel security analysis scope | PJM

less than five days of fuel on-site. It encompasses 324 “different scenarios that could occur during an extended period of cold weather” during the 2023/24 winter, including variables such as customer demand, fuel availability, oil refueling frequency, generator forced outage rates, retirements announced as of Oct. 1, new generation planned to be operational by 2023, level of reserves and natural gas pipeline disruptions.

The report provides extensive discussion to validate its assumptions, which it says are based on more than 45 years of weather data, previous studies, surveys of PJM generation owners and meetings with regulators, operators and stakeholders throughout the supply

chain.

“Even in a scenario such as extreme winter load combined with a pipeline disruption at a critical location on the pipeline system from which a significant number of generators are served, PJM’s system would remain reliable and fuel-secure. While there could be reserve shortages in the extreme winter load scenarios, the grid continues to deliver electricity reliably under these extreme conditions,” the report says.

However, when combined with “escalated” assumptions that generation reserves are

Continued on page 23



PJM Market Implementation Committee Briefs

Indemnification Conversation

VALLEY FORGE, Pa. — The PJM Market Implementation Committee will host a discussion on indemnification for financial transmission rights bilateral contracts at its Jan. 9 meeting.

The discussion, which was promised at the Dec. 5 meeting of the Markets and Reliability Committee, is intended to determine how PJM will respond to a deficiency letter FERC issued in response to one of the RTO’s proposed revisions to its FTR credit policies following the historic GreenHat Energy portfolio default.

PJM plans to request that FERC dismiss its filing, making the deficiency notice moot. But Shell Energy told the MRC on Dec. 5 that it wants to see the commission rule on the underlying indemnification issues that Shell pointed out in protesting the filing. (See “Bilateral FTR Retraction,” *PJM MRC/MC Briefs: Dec. 6, 2018*.)

FTR Collateral

Stakeholders voted overwhelmingly in favor of PJM’s original *proposal* on revising its FTR cred-



PJM’s Bhavana Keshavamurthy and Diane Antonelli administrate a special session of the MIC last week on revising the RTO’s fuel-cost policy rules. The session was held as part of the regularly scheduled MIC meeting. | © RTO Insider

Continued on page 24

Continued from page 22

reduced to the 15.8% IRM, “the system may be at risk for emergency procedures and operator-directed load shed.” The retirements announced so far would create a 25.8% IRM.

Non-firm Gas

The analysis found that 16,000 MW of gas units in PJM haven’t contracted for firm service that is only interruptible by force majeure, such as a pipeline disruption. The analysis determined that a typical winter day would have 10,000 MW, or 62.5%, of those units available while an extreme winter day of high gas demand would have 0% availability from those units.

The study’s assumptions for pipeline disruptions account for up to five days of 100% reduction and at most 20% reduction for the ensuing nine days. PJM has experienced interstate pipeline outages, or “line hits,” over the past two years as the result of both pipeline corrosion and accidental third-party damage. Outages with easily identifiable sources are

“typically” back in service within five days. However, non-point source issues may “require a longer outage and potential derating of the pipeline capacity.”

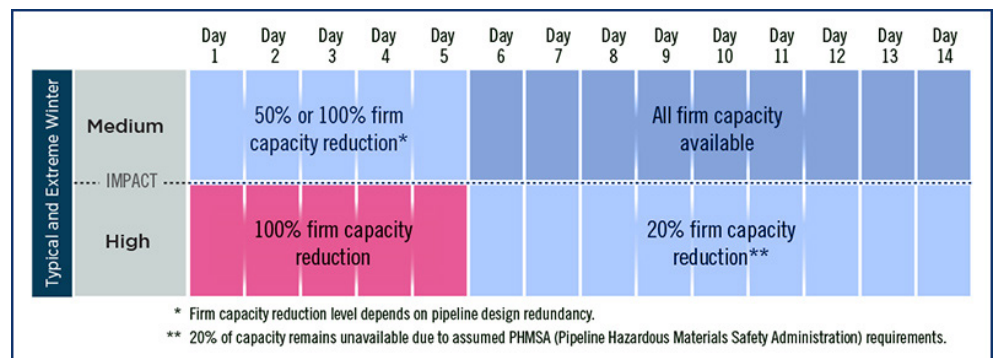
The scenarios studied only consider individual pipeline disruptions and don’t contemplate multiple simultaneous disruptions.

Results

Without escalated retirements, even an extreme weather event with 0% availability

from non-firm units and a single high-impact pipeline disruption with limited refueling availability results in no worse than reserve shortages, according to the study.

However, of the 144 scenarios in which extreme winter load is combined with escalated retirements, 73 scenarios, or 51%, required manual load shed, which would mostly be localized to one of three areas in PJM: East, West or South. The worst scenario would result in 83 hours and 204 GWh of load shed. ■



Duration of pipeline disruptions | PJM

PJM NEWS



Continued from page 23

it requirements to include a “mark-to-auction” (MTA) provision. The proposal, known in the stakeholder process as G1, received 0.93 in favor in a contemporaneous vote with several alternatives and 0.93 in favor compared to maintaining the status quo.

The proposal has the potential to delay clearing of auctions and posting of results because of intra-auction collateral calls for undercollateralized portfolios. Delayed results have happened twice in the history of PJM’s FTR markets. Both times were in March 2017, caused by “super overlapping” clearings from multiple FTR auctions ending at the same time. PJM has since implemented rule changes to avoid that situation. (See “FTR Revisions Approved over Financial Dismay,” *PJM MRC/MC Briefs*: Jan. 25, 2018.)

An alternative proposal that only applied the collateral call for portfolios undercollateralized by at least \$100,000 failed to receive stakeholder endorsement, with 0.14 in favor. Another that used the same analysis and requirements but removed bids from undercollateralized portfolios rather than making intra-auction collateral calls also failed with 0.3 in favor.

Suffolk Fund’s James Ramsey campaigned for two other [alternatives](#) that would have applied a credit requirement that is the higher of either the existing requirements or the MTA plus an adder. One included the \$100,000 threshold while the other did not. He said the endorsed proposal would be “challenging to do” because it requires forecasting many variables and might require very small collateral calls that could exacerbate [delays](#).

FTI Consulting’s Scott Harvey, retained by PJM to analyze the issue and [compare](#) the proposals, said all of the alternatives are sound, but that Ramsey’s proposals have “ad hoc parameters” that risk running down a portfolio’s initial credit margin at the wrong time because the margin declines as losses occur in the portfolio. His analysis found that two situations in the history of PJM’s FTR market wouldn’t have been covered by Ramsey’s proposals, but both were from the GreenHat default and would have been undercollateralized by more than \$20 million.

“If they have a big loss when the margin’s reduced, you have the opportunity for a big default,” Harvey said.

Ramsey’s proposals failed to receive stakeholder endorsement, with votes of 0.23 and 0.08 in favor.



Attendees discuss issues at last week’s meeting of PJM’s Market Implementation Committee. | © RTO Insider

A third set of alternatives would have combined both to make the credit requirement the higher of the current credit requirement plus the MTA or the MTA and Ramsey’s MTA adders. That set differed on the option for the \$100,000 threshold. However, they were removed from consideration before the vote.

PJM said it is targeting January to file the endorsed proposal with the intention of implementing it in April.

Fuel Cost Policy Special Session

Since the MIC’s agenda was short, staff decided to include a special session on considering tweaks to several parts of the fuel-cost policy (FCP) rules and cost-based offer procedures hashed out last year. The sessions started after

the MIC approved a problem statement and issue charge in September. (See [PJM Stakeholders Seek More Flexible Fuel Cost Rules](#).)

Joe Bowring, PJM’s Independent Market Monitor, questioned whether the process could be used to completely eliminate FCPs.

John Rohrbach of ACES, who initially proposed the re-evaluation, assured Bowring “our goal is not to vitiate” the FCP process.

“Or eviscerate? ... Just checking that you don’t want to do either,” Bowring responded.

The session identified 14 factors to consider changing or adding. ■

— Rory D. Sweeney



PJM Operating Committee Briefs

Low Frequency Update



PJM's Chris Pilog |
© RTO Insider

VALLEY FORGE, Pa. — NERC is still analyzing the causes of the July 10 low-frequency event in the Eastern Interconnection, PJM's Chris Pilog told attendees at last week's Operating Committee meeting.

In working with 12 balancing authorities, NERC doesn't believe it's an error in the reported data. It appears to have been a "drift" in the frequency that was "significant" but happens every couple of years and was never near underfrequency relay tripping or system collapse, Pilog assured.

At the September OC meeting, PJM outlined recommendations to address the situation. (See "Recommendations from Frequency Drop," *PJM Operating Committee Briefs: Sept. 11, 2018.*)

Quiet Month Operationally

Pilog said November was a very quiet month *operationally* aside from an emergency procedures drill. There was one reserve-sharing event with the Northeast Power Coordinating Council and 22 post-contingency local load relief warnings.

Both the on-peak and off-peak load-forecasting errors dropped from October, though they were slightly above the metric's score for November 2017. The overall RTO error was 1.78%.

Staff presented a graph showing that load forecasting is often worse in many zones in the



PJM Operating Committee | © RTO Insider

third quarter of the year during warm summer months. Staff used an example from July 20, 2017, when a storm in Commonwealth Edison's zone reduced actual temperatures and load below day-ahead forecasts.

The balancing authority area control error (ACE) limit performance was 99.9% for the second straight month, above PJM's 99% target. There were 15 excursions outside limits, which were down from October, and 30 minutes total outside of limits, also down from the prior month.

DER Subcommittee

PJM's Scott Baker confirmed during his *update* on the Distributed Energy Resources Subcommittee that it is considering primary frequency response requirements for resources with non-FERC jurisdictional wholesale market participation agreements. But stakeholders "actually feel it's a bigger issue" to hammer out frequency and voltage ride-through characteristics, Baker said.

In November, Planning Committee members endorsed a problem statement and issue charge to implement a new Institute of Electrical and Electronics Engineers standard on ride-through. (See "DER Ride-through," *PJM PC/TEAC Briefs: Nov. 8, 2018.*)

PMUs to Planning

Load interests are keeping a close watch on a *proposal* from PJM to include installing or retrofitting phasor measurement units (PMU) as part of projects in the Regional Transmission Expansion Plan. The units would be used to back up monitoring of interconnection reliability operating limits (IROLs). PMUs are already used to detect oscillations in the system, along with improving post-event analysis and generator model validation. PJM also plans to use them in the future for system island and event detection, automated model validation and backup ACE monitoring.

PJM's Shaun Murphy said the current IROL monitoring proposal is estimated to require 14 PMU installations and four modifications. The issue will be moved to the PC — which Murphy also addressed at its meeting last week — to

develop a standard for new substations and major construction projects to include PMU installation for bus-voltage and line-flow monitoring.

Dave Mabry, representing the PJM Industrial Customer Coalition, asked who would own the PMUs. He said he wanted to ensure PJM is "spending wisely" rather than going on a "lark" with new technology that staff "want to play with."

PJM's Paul McGlynn said the incremental cost of adding the "thousands of dollars" that a PMU costs is "relatively inexpensive in the grand scheme of [the millions of dollars that building] a substation costs." The intent would be to add them as part of baseline projects in the RTEP related to high-voltage lines.

"We're not necessarily going after every low voltage station," he said.

Mabry said he was looking for validation of the need.

"I'm trying to make sure we've got a solid business case to justify the expansion of the PMUs," he said.

OATF Base Case Parameters

PJM's Robert Dropkin said the Operating Assessment Task Force (OATF) is *building* the base case for its study of the upcoming summer to identify thermal overloads and voltage-limit exceedances in N-1 analyses. The studies, which happen annually for the summer and winter peaks, also focuses on switching and off-cost requirements and looks to develop operating procedures for any issues discovered during the study.

The OATF, which consists of the transmission owners within PJM's footprint, uses the most recent modeling from the Multi-regional Modeling Working Group (MMWG) and adds updates from individual TOs. Generator outages are calculated from the previous year and averaged with the two years previous to that. OATF members also select specific units to be put on outage based on historical or planned outages, or generators are simply reduced across the zone.

The base case will be developed in mid-February with analysis starting later that month. The final report is approved by the System Operations Subcommittee — Transmission in early May. ■

— Rory D. Sweeney



PJM PC/TEAC Briefs

FSA Unit Plan

VALLEY FORGE, Pa. — PJM is reformatting and drafting clarifications to Manual 14B: PJM Region Transmission Planning Process that may impact the RTO's planning modeling, staff told attendees at last week's Planning Committee meeting.

The proposed *revisions* would clarify that units with facility service agreements (FSAs) will only be added to the base case if there are not enough existing units and units with interconnection service agreements (ISAs). Units with FSAs that are not included in the base case will be subject to a sensitivity study to determine if long-lead-time upgrades are required to support them. The long-term base case will only be studied if the need for a long-lead-time upgrade is identified during the near-term base case analysis extrapolation over Years 6 through 15.

Additional clarifications include:

- Higher-than-normal capacity interconnection rights (CIRs) may be granted to wind units when justified by meteorological data.
- Flowgates near PJM's borders will continue to be examined to understand deliverability concerns that may exist due to loop flows.
- Merchant transmission facilities (MTFs) with long-term firm transmission service will be modeled the same as MTFs with firm transmission withdrawal rights.
- Operational contingencies are single contingencies examined under the common-mode outage procedure to determine whether system operators would allow the common-mode dispatch to occur.
- Constraints identified in the PJM capacity import limit (CIL) analysis are studied in the same manner as other internal PJM constraints.
- The distribution of the capacity benefit margin from each of the five external supply zones is determined during the annual PJM CIL study.

PJM's Jonathan Kern said the clarifications were intended to be pre-emptive measures to avoid confusion in the future.

Inverter-based Model

Staff plan to *update* Manual 14G: Generation Interconnection Requests to identify which user-defined models (UDMs) it has already



PJM Planning Committee | © RTO Insider

approved for wind turbines and other inverter-based resources. Developers planning to build affected generators would need to use the tables to determine whether they would need to submit additional information about modeling their units to receive PJM approval.

PJM's Tao Yang said the list would likely be updated annually.

PJM's Ken Seiler, who chairs the PC, said standardizing the stability modeling is important so generation interconnection requests can be processed "much faster."

ELCC Analysis of Intermittent Resources

PJM's Tom Falin said the RTO is targeting an endorsement vote at the March meeting of the PC for a package of four changes for how capacity credits are calculated for intermittent resources.

One of the prospective changes, resources' effective load carrying capability (ELCC), has received "a lot of discussion lately," Falin noted. PJM scheduled a special session of the PC on Dec. 21 so the RTO can get "a read" on stakeholders' interests. (See "Renewables' Capacity Analysis Extended," *PJM PC/TEAC Briefs: Nov. 8, 2018*.)

The question to answer, he said, is "do we think moving to an ELCC methodology is the right thing to do?"

PJM's Jerry Bell will return to the PC in January to reintroduce the proposed changes with whatever consensus on the ELCC is gleaned

from the special session.

Cost Containment

PJM's Mark Sims said staff have *gathered* all of the pieces necessary to develop the comparative framework for cost containment and return on equity that stakeholders endorsed earlier this year. (See "Update on Integrating Cost-containment Guarantees," *PJM PC/TEAC Briefs: Sept. 13, 2018*.)

"The moving parts we're dealing with ... include not only the uniqueness of the proposals that we might receive but ... the complexity of the cost-containment proposals we might receive ... [so] there's a couple of big moving parts," Sims said. "We have all the building blocks we need to pull the process together in 2019. ... We can see where all the pinch points are."

As part of the process, PJM and its Independent Market Monitor met with an independent consultant on Nov. 15 to better understand cost estimating, revenue requirements and other components for developing cost proposals. PJM continues to work with the contractor, and stakeholders questioned how the RTO would handle a situation if the contractor eventually took a contract that created a conflict of interest. PJM's Sue Glatz said it "would be a given" to re-evaluate the relationship if staff "saw anything" that affected the contractor's independence, but that "right now we don't see any conflicts."

Sims said he plans to return to the committee in January with more detail on the process.

PJM NEWS



MEPETF

Work in the Market Efficiency Process Enhancement Task Force (MEPETF) has progressed to polling on how to proceed with revising the market-efficiency process, PJM's Fran Barrett said. At the task force's Dec. 7 meeting, stakeholders developed a *list* of nine questions for the poll, including the preferred method for re-evaluating already-approved market efficiency projects and the preferred cycle for PJM to conduct the market-efficiency process.

"That means we've got a lot of work in January and February. It's going to be pretty swift and a lot of hard work," Barrett said.

Staff are targeting the March PC meeting for a first read of the most popular options so the package proposal can be implemented on Nov. 1.

Offshore Wind Zones

With many coastal states announcing offshore wind solicitations, PJM is now developing *concepts* for alternative ways to interconnect all of the coming megawatts, Glatz said. She explained that developers have approached staff with challenges and said they'd like to have multiple interconnection points, along with the ability to create offshore transmission networks. Staff are considering how to handle those desires and are seeking input from the PC on a variety of questions, including what studies might be required, what interconnection rights might be offered and whether the rights could be transferrable.

Glatz said staff are targeting the January or February meetings of the PC to introduce proposed concepts and related Tariff revisions. Stakeholders said they had no foundation on which to base their input and called on staff to create a problem statement and issue charge on the topic. But staff voiced concerns about the initiative getting bogged down in debates.

"We have real projects today, so the challenge is how can we be responsive to our customers?" Glatz said, adding that states want to limit impacts to communities while also providing the necessary resources.

The plan is potentially a move toward creating open-access offshore networks as an extension of the onshore grid that has been advocated by stakeholders like Markian Melnyk, president of Atlantic Grid Development. (See [Offshore Wind Industry 'Really Moving;' Coordination Key.](#))

However, PJM is currently considering only plans that are "strictly for injecting into PJM,"



PJM's Nick Dumitriu discusses planned transmission projects during last week's meeting of the RTO's Transmission Expansion Advisory Committee as meeting administrators Ken Seiler and Lisa Krizenoskas look on. | © RTO Insider

not connecting to other RTO/ISOs, Glatz said.

2019 Load Forecast



PJM's John Reynolds | © RTO Insider

The RTO's preliminary 2019 load *forecast* is down compared to last year, PJM's John Reynolds explained. Both the summer and winter forecasts are down at least 0.4% from last year's forecasts.

The analysis uses the summer forecasts for 2022 and 2024 and the winter forecasts for 2021/22 and 2023/24 to make year-over-year comparisons. The summer 2024 comparison is down 0.5%, slightly more than the other three. Staff are adding a zone summary page for 2019 that details zonal impacts.

The report remains preliminary for now because there were issues with forecasts in the Dayton Power and Light and East Kentucky Power Cooperative zones that are still being revised. The final version, expected by the end of December, will be used for all Regional Transmission Expansion Plan studies.

Because the Base Residual Auction is delayed this year to attempt to implement revisions to the capacity auction construct, PJM staff will develop a second load forecast just for the BRA that would include peak-shaving adjustments.

Reynolds confirmed that the forecast only includes load that PJM system planning staff are working on and nothing speculative.

Planning Resilience

PJM's Aaron Berner presented *analysis* from staff's recent initiative on developing "cascading trees" on load-loss probabilities that shows one facility has a high probability of losing at least 1,000 MW of load.

"This gives us an idea about potential weaknesses based on initiating events," Berner said, but he cautioned that more work will be necessary to make sure staff are not "looking at things we shouldn't be."

Deactivation and Acceleration

PJM's Nick Dumitriu said the 2018 reliability project acceleration *analysis* found no projects to accelerate to reduce congestion. Project B2766 would ease congestion, but it was already accelerated last year to 2020 and the developer said it can't be accelerated further.

PJM is performing reliability *analyses* for deactivation of 30 units, all of which have requested to deactivate no later than June 1, 2020.

Dominion

Dominion Energy's Ronnie Bailey presented three new need assessments and three planned solutions as part of the transmission owners' new FERC-ordered process for developing supplemental projects. Dominion has presented 19 needs assessments since the process was implemented in September. Dominion has been presenting such needs and planned solutions for several months. (See "Dominion Supplementals," [PJM PC/TEAC Briefs: Oct. 11, 2018.](#)) ■

— Rory D. Sweeney



State Regulators Still Frustrated with PJM

By Michael Brooks

WASHINGTON — The tension between PJM and certain states has not loosened, judging by comments made at a forum held by the Great Plains Institute and Duke University's Nicholas Institute on Environmental Policy Solutions last week.

During a panel on PJM and state authority over resource adequacy, Illinois Commerce Commission Chairman Brien Sheahan and New Jersey Board of Public Utilities Commissioner Mary-Anna Holden took the RTO to task over several issues, including its latest proposal to revise the capacity market to factor in their states' subsidies for zero-emission resources.

Holden said that while she thinks the relationship between her state and PJM has improved, she was incensed by a recent letter from the RTO's Board of Managers giving stakeholders a Jan. 31 deadline to reach consensus on several energy price formation issues. (See [PJM Board Demands Action on Energy Price Formation](#).)

"We'd like to have representation in the stakeholder process," Holden said. "Yes, a stakeholder process takes place, but we'd like to have respect in the stakeholder process. And that when we're moving towards an answer, not to come out with a letter of decree from PJM saying, 'Well, you didn't work fast enough, so we're just moving ahead,'" she continued, holding a copy of the letter aloft. "That's not good governance, and that's not communicating or collaborating."

"I would second all of that," Sheahan said. "I think the letter certainly has rubbed people the wrong way."

Sheahan expressed appreciation for PJM's position. "They have a very, very difficult job. ... There is enormous tension between the job they have and the policies that states express."

But, he added later, "I really don't know how that tension gets resolved." He noted that he has advocated for Commonwealth Edison, whose Chicago service territory is in PJM, to join MISO, which encompasses the rest of Illinois. But he said the solution may be for the state to not participate in PJM's capacity market. "I think PJM may just have to decide, 'Look this is the best we can do, and if it doesn't fit for your state, we have some other alternatives.'"

Sheahan's opinion echoed that of Independent



From left to right: Panel moderator Jennifer Chen, Nicholas Institute; M. Beth Trombold, Ohio PUC commissioner; Brien Sheahan, Illinois Commerce Commission chairman; Mary-Anna Holden, New Jersey BPU commissioner; and Norman Bay, Wilkie Farr & Gallagher. | © RTO Insider

Market Monitor Joe Bowring, who gave a presentation on several PJM market issues prior to the panel, including his firm's own proposal for the capacity market. "If units don't clear, then as far as we're concerned, they're not capacity resources," Bowring said. "If states want to maintain them, they're free to do that, but they do not get capacity market revenues. So the capacity market does not change; we don't need some hugely complicated, impossible-to-understand set of rules to make sure they really clear and force out competitive units. If they're not competitive, they're not competitive; they should not clear. ...

"If you want to maintain cost-of-service regulation in the state, that's fine, but rather than acting as if you were a market competitor, you should simply offer in as" a fixed resource requirement.

The RTO's energy market is working well and also does not need a complete overhaul, Bowring argued. On that point, Norman Bay, a former FERC chairman who is now a partner at Wilkie Farr & Gallagher, agreed. Throughout the panel, it often fell to Bay to act as a calming presence as a counter to Sheahan's and Holden's frustrations.

"We should acknowledge that the energy market in PJM works well, and it's producing competitive outcomes from which consumers have benefited," Bay said. "PJM deserves a lot of credit with respect to the energy market. It's the capacity market that seems to have engendered the greatest amount of controversy."

Bay suggested asking FERC to hold a technical



Joe Bowring | © RTO Insider

conference on stakeholder processes in RTOs and ISOs. He cited the D.C. Circuit Court of Appeals ruling last year that FERC had overstepped its bounds in suggesting to PJM what revisions to the RTO's minimum offer price rule it would accept. (See [PJM MOPR Order Reversed; FERC Overstepped, Court Says](#).)

The ruling, written by now Supreme Court Justice Brett Kavanaugh, said the commission could only suggest minor, technical or administrative changes, not "modifications that result in an entirely different rate design than the utility's original proposal or the utility's prior rate scheme."

"Thus, the RTO/ISO stakeholder process is more important than ever," Bay said. "Which means that, given the importance of the process, I think it is critical that stakeholders have a seat and voice at the table." He said many stakeholders — not just state regulators in PJM — have concerns about the processes.

FERC Commissioner Richard Glick, who gave a keynote luncheon speech at the event, noted that as well. He said he attended a recent Edison Electric Institute conference, and "I was amazed at how many people came up to me to complain about RTO governance in general. ... People from all sides of various issues."

He said it would be worthwhile for FERC to look at the issue, though he did not have any specific suggestions. Both he and Bay noted that it had been a long time since the commission examined RTO governance. In 2008,



Richard Glick | © RTO Insider

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PJM MRC Preview

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

RTO Insider will be in Valley Forge, Pa., covering the discussions and votes. See next Tuesday's newsletter for a full report. (NOTE: The meeting will be held at PJM's Conference and Training Center instead of the Chase Center.)

MARKETS AND RELIABILITY COMMITTEE

Informational Update (9:10-9:25)

PJM Board of Managers member Susan Riley will provide an update via phone on the progress of the Special Board Committee investigating PJM's handling of the GreenHat Energy financial transmission rights portfolio default.

1. PJM Manuals (9:25-9:40)

Members will be asked to endorse the following manual changes:

A. Manual 14D: *Generator Operational Requirements*. Revisions developed to revise information input deadlines for the Resource Tracker application. (See "Resource Tracker," *PJM*

Operating Committee Briefs: Nov. 6, 2018.)

B. Manual 14E: *Upgrade and Transmission Interconnection Requests*. Revisions developed as part of a triennial cover-to-cover review. The revisions include changing the manual name to align it with the structure of Manuals 14A and 14G and explaining how to apply to the interconnection queue via Queue Point.

2. FTR Mark-to-auction Credit Requirements (9:40-10:05)

Members will be asked to approve a *proposal* endorsed by the Market Implementation Committee to increase FTR credit requirements with the addition of a "mark-to-auction" provision. (See "FTR Collateral," *PJM Market Implementation Committee Briefs: Dec. 12, 2018.*)

3. Must-offer Exception Process (10:05-10:30)

Members will be asked to endorse a *proposal* endorsed by the Market Implementation Committee to revise the capacity market must-offer exception process. The changes would allow participants to specify multiple auctions when making exception requests. Resources that cannot be made Capacity Performance-capable by the start of the delivery year will be permitted to seek an exception. (See "Must-offer Exception Changes," *PJM Mar-*

ket Implementation Committee Briefs: Nov. 7, 2018.)

4. FTR Forfeiture Rule (10:30-10:55)

Members will be asked to endorse a *proposal* endorsed by the MIC to revise the FTR forfeiture rule. It would specify that a binding constraint shall be considered if the difference between the shift factors at the FTR delivery and receipt buses across the constraint exceeds 10% and is in the direction that increases the value of the FTR. (See "FTR Forfeiture Proposal Endorsed," *PJM Market Implementation Committee Briefs: Nov. 7, 2018.*)

5. Primary Frequency Response Senior Task Force (10:55-11:15)

Members will be asked to *consider* putting the task force on hiatus for one year to gather data and subsequently determine whether to reconvene. (See *PJM SHs Seek End to Frequency Response Debate.*)

6. Distributed Energy Resources (11:15-11:40)

Members will be asked to endorse proposed *clarifications* of market participation rules for distributed energy resources. Among the changes are a consistent definition of on-site generators. ■

— Rory D. Sweeney

Continued from page 28

FERC *Order 719* required that each grid operator "increase its responsiveness to customers and other stakeholders."

Sheahan's and Holden's sentiments have been shared by other regulators on their commissions this year. (See *PJM Flexible on Capacity Rules, Ott Tells OPSI Meeting* and *NJ Regulator Threatens to Exit PJM Amid States' Complaints.*)

For his part, Bowring said he believes that PJM stakeholder process, "as difficult as it is, has been working just fine. ... The stakeholder process is messy ... it could be made more efficient. But real issues are debated, real interests are debated and, from my perspective, it has worked very well. The fact that it doesn't do what one party or another wants, as quickly as they want, is not a sign that it's not working; it's a sign that it is working."

Stu Bresler, PJM senior vice president of markets and operations, defended the RTO's capacity market filing in a presentation prior to the panel. PJM's proposal was "really, despite what you may read out there in the press,

aimed at accommodating these state policy decisions."

"There are no easy answers. There are very tough questions with which we are all wrestling," Bresler said. "From PJM's standpoint, what we want to do is make sure that we continue to engage with our federal regulator, our state commissions and all our stakeholders, to work our way through these issues."

"PJM is a member organization," spokesman Jeff Shields said in an email. "The decision to remain as a member resides with those PJM members."

"We respect the rights of states to determine the mix of generators within their borders, and we have worked with FERC and our stakeholders on recently filed proposals that seek to maintain the integrity of the market while respecting state policy initiatives."



Stu Bresler | © RTO Insider

Looking Ahead

True to the event's name — "Looking Ahead: Big Challenges in 2019" — many attendees asked speakers and panelists how they thought FERC might rule on the capacity market proceeding.

The abridged version of everyone's answers: No idea.

But whatever FERC issues, many speakers hoped for a solution that lasts. "It would just be nice to have some consistency," Holden said. The capacity market "has changed 30 times in 10 years," she said.

"I don't know where the commission will end up on this, but I do think that whatever design the commission considers, that it should be sustainable and durable," Bay said. "I think that it is very hard for stakeholders to deal with significant changes to market design every few years."

"Good market design is self-sustaining," Bowring said in closing his presentation. ■



FERC Rejects SPP Confidentiality over NERC Fine

By Tom Kleckner

FERC last week denied SPP's request for waivers from regulations guiding the confidential treatment of information in its explanation of how it allocated costs related to a NERC fine, the amount of which has not been publicly disclosed because of grid security concerns (ER19-97).

SPP filed the Section 205 request in October with an explanation of its allocation of costs from a NERC fine for violating reliability standards. The heavily redacted *public version* of the request shows the RTO asked for waivers from the requirement to include a protective agreement and from the regulations authorizing release of the filing's confidential version to entities signing a nondisclosure agreement. SPP claimed that disclosing the information could jeopardize its system's security.

But FERC ruled that "SPP has neither adequately supported its concerns nor justified the adverse effect that its waiver request would have on participants in this proceeding." As the cost allocation plan did not include a proposed protective agreement, the commission dismissed it. It did so without prejudice, meaning SPP can refile its proposal for covering the penalty without the waiver request.

FERC noted intervenors would be willing to sign a protective agreement to review SPP's filing and evaluate its proposed cost allocation.

In the cost allocation filing, SPP said it paid the penalty costs using surplus funds, although a Tariff provision allows the recovery of such costs by direct assignment or cost allocations



SPP's headquarters in Little Rock, Ark. | WER Architects

to members or market participants. The RTO's Board of Directors approved offsetting the costs with employee compensation funds for 2018, an approach SPP said it adopted from FERC Order 693, which it said suggested RTOs and ISOs could tie employee compensation to compliance with reliability standards as a means of reducing repeat occurrences of penalties. The order also declined to provide grid operators blanket authority to recover penalty costs from members on a generic basis.

Under the board's recommendation, the reduction in compensation would be reflected as a surplus in the administrative fee's true-up for 2018, which would reduce the fee for 2019.

The West Texas Municipal Power Agency (WTMPA), created by the cities of Lubbock, Brownfield, Floydada and Tulia to increase their negotiating strength, intervened in the docket. While it did not protest the cost allocation plan

or waiver request, it urged FERC to "strictly and expressly limit such findings to this case" if it approved them. The agency asked that interested parties be allowed access to information about the penalties and cost allocation, contending that it would be otherwise impossible for ratepayers to determine whether the penalty's allocation was just and reasonable and not unduly discriminatory.

FERC regulations provide that any participant in a proceeding can make a written request to the filer for a copy of the document's complete, nonpublic version. The request must include a signed copy of the filer's protective agreement and a statement of the person's "right to party or participant status or a copy of their motion to intervene or notice of intervention."

SPP members Evergy, Oklahoma Gas & Electric and Western Farmers Electric Cooperative also intervened in the docket. ■

GCPA

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**If You're not at the Table,
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Contact Marge Gold (marge.gold@rtoinsider.com)

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FERC & FEDERAL NEWS

FERC Clears Cleco to Buy NRG Generation in South

By Amanda Durish Cook

FERC last week approved Cleco's \$1 billion acquisition of eight NRG Energy generation assets in MISO South, ruling the transaction will not have an adverse impact on rates or create market power concerns ([EC18-63](#)).

The deal is pending approval by the Louisiana Public Service Commission ([U-34794](#)).

Louisiana-based Cleco announced the [acquisition](#) early this year. NRG South Central Generating will hand over eight generating assets totaling 3,555 MW; transmission operations; and wholesale power contracts to nine Louisiana cooperatives, five municipalities in Arkansas, Louisiana and Texas, and one investor-owned utility.

Most of the plants will be operated by Cleco, except the 1,279-MW, natural gas-fired Cottonwood Generating Station in East Texas, which will be leased back to NRG, who will operate it until May 2025. NRG purchased the Cottonwood plant in 2010.

Cleco plans to create a new affiliate, Cleco Energy, to oversee NRG South Central Generating's assets. Cleco had targeted a year-end close for the sale.

In issuing the decision, FERC considered that Cleco and NRG South Central Generating both own generation in MISO's West of the Atchafalaya Basin (WOTAB) narrowly constrained area that frequently binds. FERC previously issued a deficiency letter over the transaction, requesting additional transmission constraint and price separation analyses for MISO South and the WOTAB load pocket. However, FERC concluded that the acquisition is "unlikely to have an adverse effect on competition ... in any relevant market."

In addition to the Cottonwood plant, the sale also includes the Big Cajun, Big Cajun II, Bayou Cove and Sterlington power plants in Louisiana.

In related orders issued the same day, FERC approved a change in upstream ownership to NRG plant operating subsidiaries for the Louisiana plants ([ER14-2080-001](#)) and the



Big Cajun II | NRG Energy

Cottonwood plant ([ER14-1619-004](#)). While FERC accepted informational filings on both, it opened an investigation and settlement proceeding into the plants' reactive power rates, saying the rates may not reflect the degradation of the facilities' capability. FERC also said Cottonwood's reactive service schedule uses an outdated federal income tax rate. ■

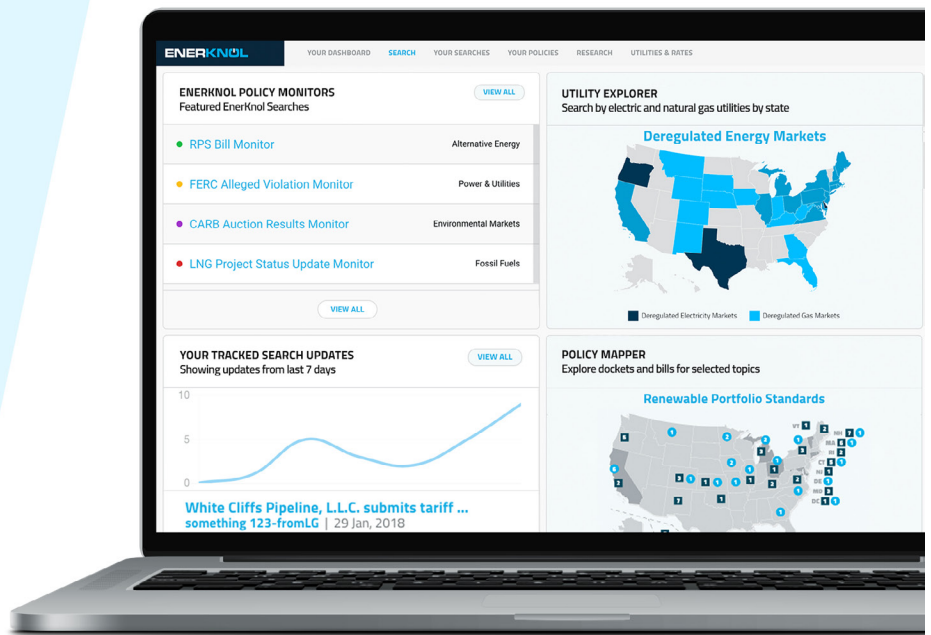
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Company Briefs

SCPSC Approves Dominion's Purchase of SCANA



The South Carolina Public Service Commission last

week unanimously approved Dominion Energy's \$7.9 million purchase of SCANA, after the Virginia-based company agreed to a rate cut for customers of up to \$22/month.

Ratepayers, however, will end up paying another \$2.3 billion for the failed V.C. Summer nuclear plant, a condition of the deal that Dominion insisted upon, having threatened to walk away if it was not included.

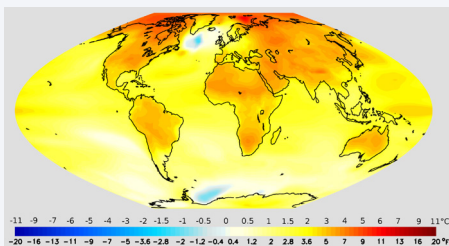
Dominion also agreed to give one of its board seats to a current SCANA board member, maintain SCANA's headquarters to Cayce, S.C., and not to reduce SCANA employees' salaries until at least July 1, 2020.

More: [The State](#); [Bloomberg](#)

Analysis Finds Companies Underestimating Climate Risk

An analysis of 1,630 large companies' corporate disclosure forms found that companies are underestimating the risks posed by climate change by trillions of dollars.

Estimates of climate impacts on the global



financial sector range from \$2.5 trillion to \$24.2 trillion. Yet the aggregate impact reported by the surveyed companies only amounts to tens of billions of dollars, the report found.

The huge discrepancy "reflects both that a large number of companies do not report financial impacts and that many that do are probably underestimating them," according to the [report](#), published in Nature Climate Change. The authors also note the investments of several companies, such as Google parent Alphabet, Hitachi and Entergy, as examples of what other companies should be doing.

More: [Quartz](#); [Bloomberg](#)

Destructive Shmoon Malware Hits Italian Energy Company

Italian oil and gas company Saipem last week said it was attacked by hackers using a new



variant of the destructive computer virus, Shmoon.

The virus, most notably used against Saudi Arabian and Qatari state oil companies in 2012, overwrites infected systems' files with image files, rendering the computers virtually useless. Saipem said its servers around the world were attacked.

More: [Axios](#)

Westmoreland CFO Resigns amid Bankruptcy



Westmoreland Coal CFO **Gary Kohn** last week announced his resignation from the bankrupt company effective early next month.

Kohn received \$1.2 million in incentive bonuses in addition to his \$472,000 salary during the year leading up to Westmoreland's bankruptcy filing. He said he was resigning for personal reasons.

The company has been under fire for requesting retention bonuses for executives from U.S. Bankruptcy Court.

More: [Casper Star-Tribune](#)

Federal Briefs

Zinke Resigns as Interior Secretary



Secretary of the Interior Ryan Zinke last week announced his resignation, effective Dec. 31, amid numerous ethics investigations.

"I love working for the president and am incredibly proud of all the good work we've accomplished together," Zinke [tweeted](#) Saturday. "However, after 30 years of public service, I cannot justify spending thousands of dollars defending myself and my family against false allegations."

President Trump seemed to overlook the bad press Zinke had been gaining while he focused his wrath against former Attorney General Jeff Sessions. But according to The New York Times, aides convinced Trump to force Zinke out, given that Democrats

have signaled that Zinke and the Interior Department would be at the top of their list of investigations once they reclaimed the majority in the House of Representatives on Jan. 3.

More: [The New York Times](#)

Democrats Install Manchin as ENR Ranking Member



Senate Democrats last week ratified Sen. Joe Manchin (W.Va.) as ranking member of the Energy and Natural Resources Committee for the next session of Congress.

"The problems facing our country are serious, and I am committed to working with my colleagues on both sides of the aisle to find common-sense solutions for long-term comprehensive energy policy that incorporates an all-of-the-above strategy and ensures

our state and our nation are leaders in the energy future," Manchin said in a statement.

Current ENR ranking member Maria Cantwell (Wash.) was chosen to be the top Democrat on the Commerce, Science and Transportation Committee. Progressive Democrats had hoped Sen. Bernie Sanders (I-Vt.) would replace Cantwell, but he elected to remain ranking member of the Budget Committee.

More: [The Washington Post](#); [Roll Call](#)

Canada Releases Plan to Phase out Coal by 2030



The Canadian government last week released a plan for achieving its goal of

completely phasing out the use of coal for electricity generation by 2030 and produce 90% of its power using clean resources.

The plan involves ramping up interprovincial transmission development, necessary to transmit large amounts of renewable power over long distances. The government also announced new greenhouse gas regulations on natural gas-fired electricity, which it said

“will both support the coal phase-out and create good, well-paying jobs in the electricity sector.”

Canada only gets about 9% of its power from coal, and many provinces already get

more than 90% of their power from hydro-power, renewables and, in Ontario’s case, nuclear.

More: [Government of Canada; Business in Vancouver](#)

State Briefs

ARKANSAS

AG Rutledge Requests PSC Review Entergy Settlement



Attorney General **Leslie Rutledge** last week asked the Public Service Commission to review a settlement between Entergy Arkansas and the Sierra Club involving several of the company’s

fossil fuel plants in the state.

Under the deal, which ended a lawsuit by the Sierra Club and National Parks Conservation Association, Entergy will stop using coal no later than the end of 2028 at its White Bluff plant and by the end of 2030 at its Independence plant. It will also cease operation of its Lake Catherine natural gas plant by the end of 2027.

“This settlement has not been properly vetted by the Public Service Commission, my office or other agencies that have the public’s interest at heart,” Rutledge said in a statement. She also said she would petition U.S. District Court to intervene in the case.

More: [Arkansas Times](#)

CALIFORNIA

Air Resources Board Mandates 100% Electric Bus Fleet



The Air Resources Board last week approved a new rule requiring all state transit agencies to completely

replace their bus fleets with zero-emission electric buses by 2040.

The rule means the state will produce or purchase more than 14,000 new zero-emission buses.

More: [The Hill](#)

LOUISIANA

Entergy Sues PR Firm for Actor Scandal



Entergy New Orleans last week filed a

lawsuit in U.S. District Court against the Hawthorn Group, the public relations firm that hired professional actors to play supporters of a company power plant at City Council meetings.

Entergy is seeking reimbursement of the costs of the city’s investigation into the controversy.

“Hawthorn acted intentionally, grossly deviated from the applicable standard of care of similar professionals, and acted in bad faith,” the lawsuit says.

More: [The Advocate](#)

MAINE

PUC Sets CMP Standard Offer Service Rates



The Public Utilities Commission last week set Central Maine Power’s stan-

dard offer service rates for next year after a competitive auction it held.

The PUC set a 9-cent/kWh rate for residential and small business customers, a 13.7% increase over this year’s rate. For medium-business customers, the average rate will be about 8.95 cents/kWh, about 7.8% higher than this year’s.

“These price increases are driven by increases in wholesale electricity market prices in New England due primarily to constraints on the availability of natural gas in the region,” PUC Chair Mark Vannoy said. “The region’s natural gas delivery infrastructure has expanded only incrementally, while reliance on natural gas as the predominant fuel for both power generation and heating continues to

grow. The region has yet to address New England’s natural gas infrastructure needs.”

More: [Maine Public Utilities Commission](#)

MASSACHUSETTS

DOER Releases Comprehensive Energy Plan

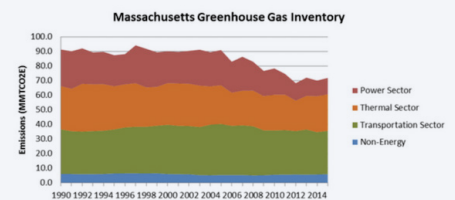


Figure 2: Massachusetts Greenhouse Gas Inventory

After two years of work, the Department of Energy Resources last week released a 213-page Comprehensive Energy Plan for the state, calling for rapid electrification of the state’s transportation sector and aggressive energy efficiency measures.

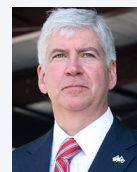
The state’s electricity prices are among the highest in the U.S., especially in the winter. Among the plan’s recommendations are tightening building codes to make them more energy efficient.

But the plan also notes that in 2016 transportation accounted for 44% of the state’s energy use, compared to the electricity sector’s 17%. Emissions from electricity generation have also dropped since 1990, while those from transportation have remained relatively steady.

More: [The Republican](#)

MICHIGAN

Snyder Signs Bill Allowing for Line 5 Replacement



Gov. **Rick Snyder** on Wednesday signed a bill that will allow for the replacement of Enbridge’s dual oil and natural gas liquids pipelines, collectively known

as Line 5, in the Straits of Mackinac.

The bill, which Snyder signed the day after it passed the Legislature, created the Mackinac Straits Corridor Authority, which is required to sign an agreement by Dec. 31 for the construction, maintenance and operation of a new underwater tunnel to encase a new segment of the line.

Snyder, who leaves office on Jan. 1, also appointed the authority's three members the same day. Most Democrats in the Legislature, and some Republicans, voted against the bill, arguing that it would tie the hands of Democratic Governor-elect Gretchen Whitmer. They also faulted it for not guaranteeing that state workers would build the tunnel and new segment.

More: [Crain's Detroit Business](#); [The Associated Press](#)

MINNESOTA

Metro Transit Seeking to Add Electric Buses

 The Twin Cities' Metro Transit last week released a plan to begin adding electric buses to its fleet, with up to 125 by 2022.

The agency will start by putting eight new electric buses on the roads next year. By 2022, it will stop purchasing diesel buses for the fleet, beginning a transition to 100% electric.

Metro Transit is interested in seeing how the first additions do during the state's often brutally cold winters, particularly whether they can provide the same level of heating for passengers as traditional buses.

More: [Energy News Network](#)

NEW YORK

NYP&A Budget Includes \$500M+ for Storage, DER



The New York Power Authority board of trustees last week

approved the organization's 2019 budget, which includes more than \$500 million for the development of energy storage, demand management, microgrid, electric vehicle charging and other distributed energy resources.

The funding includes \$250 million for up to 150 MW of storage and demand management demonstration projects; \$5 million for projects under the Clean Distributed Energy Resource Grant Program; \$81.7 million for installing sensors at generation and transmission facilities to digitize communications; and \$250 million for EV charging infrastructure.

More: [Microgrid Knowledge](#)

RHODE ISLAND

Town Places Moratorium on Utility-scale Solar



The Exeter Town Council last week voted 3-1 to pass an emergency, temporary moratorium on utility-scale solar projects, saying the 12 proposals before the Planning Board have overwhelmed it amid changing rules.

The 12 projects were proposed when several different sets of rules were in place and before an election that changed most of

the council. The multitude of rule changes overwhelmed the board and its town planner, who only works two days a week. Just keeping track of where each project was under which set of rules, Town Planner Ashley Hahn-Sweet told the council, took up 90% of her time.

Planning Board Chairman Michael De-Francesco said the 60-day halt will give the board the chance to untangle all of the different rules. Council member Daniel W. Patterson, the only member re-elected in the last election, was the lone vote against the decision.

More: [Providence Journal](#)

WASHINGTON

Inslee Proposes Suite of Climate Change Legislation



Gov. Jay Inslee last week proposed a package of bills that would help the state reduce its carbon emissions and, he said, counter the effects of climate change.

Included in the package are proposals to completely reduce utilities' use of fossil fuel-fired electricity by 2045, a clean-fuels standard for vehicles, incentives for electric vehicles and increased energy-efficiency regulations for buildings.

"We know that there is a mighty chorus of people demanding climate action," Inslee said a press conference announcing the proposals. "And we know that we have the responsibility of this more so than ever because, unfortunately, we have climate denial ruling the roost on Pennsylvania Avenue."

More: [The Seattle Times](#)

If you're not at the Table, You may be on the menu

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For more information, contact Marge Gold (marge.gold@rtoinsider.com) or 240-750-9423