RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ■ ERCOT ■ ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

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Peak/PJM Enter Western Market 'Commitment Phase'

By Jason Fordney

Peak Reliability and PJM Connext have entered the "commitment phase" for their proposed Western energy market, refining their pitch to convince potential participants to finally embrace an organized market for the region.

The organizations on Friday issued a three-page abstract of their new business plan to potential members and has also set up a public comments page on a partnership for what could possibly lead to a Western RTO, an effort that has previously been stymied by difficulties in developing a governance process acceptable to all the states involved.

"It is envisaged that these services will expand over time, evolving towards a full RTO offering. Whether and when this occurs will be a matter for the market's participants to determine," the abstract says. The full business plan remains confidential and will require interested parties to enter nondisclosure agreements.

In response to the proposed market plan, CAISO has filed to depart Peak as its reliability coordinator (RC) and developed a rival plan to offer RC services across the West to Peak's existing customers. (See *CAISO to Depart Peak Reliability, Become RC*.) The ISO is also exploring enhancing its day-ahead market and extending it across the Western Energy Imbalance Market (EIM). (See *Multiple Entities, Markets Now Beckon in West*.)

Continued on page 30

FES Seeks Bankruptcy, DOE Emergency Order

Davis-Besse, Beaver Valley Nukes Closing

Davis-Besse nuclear plant | *NRC*

By Michael Brooks

FirstEnergy Solutions filed for bankruptcy Saturday, two days after asking Energy Secretary Rick Perry to issue an emergency order directing PJM to compensate coal-fired and nuclear power plants that have 25 days of onsite fuel.

The request from FirstEnergy's competitive power business came a day after the company announced that it will close its three nuclear plants — Davis-Besse and Perry in Ohio, and Beaver Valley in Pennsylvania — by 2021.

Late Saturday night, the subsidiary filed for Chapter 11 protection in U.S. Bankruptcy Court in Akron, Ohio. The move has been

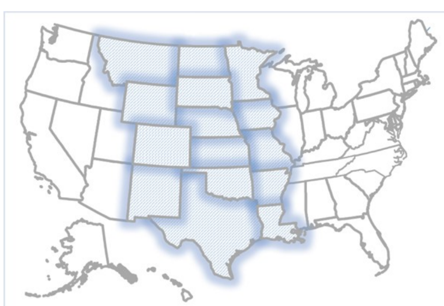
Continued on page 33

Is RTO Tx Planning Hampering Green Corporate Goals?

By Rich Heidorn Jr.

Unilever, which sells Breyers ice cream, Dove soap and hundreds of other consumer products, plans to eliminate coal from its energy mix by 2020. It hopes to become "carbon positive" by 2030, by supporting the generation of more renewable energy than it consumes.

Thus far, the company has used onsite solar and power purchase agreements for Texas wind power. But the company has been frustrated in its inability to do more. "If we're buying wind in Texas and trying to get it to my plant in Virginia, in Tennessee, in Missouri … right now we're just not able to do that," Stefani Millie Grant, the company's senior manager for external



Fifteen Midwestern states have 88% of the U.S.'s total onshore wind potential and 56% of its utility-scale solar PV potential. But they are far from load centers and will consume only 30% of projected electricity sales in 2050. | *David Gardiner and Associates, for the Wind Energy Foundation*

Continued on page 31

Also in this issue:

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Editorial

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

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

Production Editor
Michael Brooks 301-922-7687

Contributing Editor
Peter Key

CAISO/West Correspondent
Jason Fordney 571-224-8960

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 and Advertising

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

Account Executive
Marge Gold 240-750-9423

Marketing Assistant
Ben Gardner

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

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IN THIS WEEK'S ISSUE

CAISO News

CAISO Storage, DER Plans Progressing

By Jason Fordney

FOLSOM, Calif. — Energy storage and distributed energy resources stand to play a bigger role in markets as CAISO moves forward with its latest proposal to integrate and compensate the emerging technologies, ISO staff said last week.

The scope of the Energy Storage and Distributed Energy Resources Phase 3 (ESDER 3) initiative is still taking shape, CAISO Infrastructure and Regulatory Policy Specialist Eric Kim said as he led a March 29 working group in analyzing the design elements.

"Nothing is set in stone," said Kim, adding that interested parties should file comments with the ISO by April 9.

"What are some things we are not considering?" he asked.

The all-day session provided a view into the extremely technical process of integrating resources that behave in different ways, with new engineering, regulatory and market rule challenges.

CAISO is still gathering stakeholder input on its ESDER 3 straw proposal, issued in February. The ISO said the purpose of the proposal "is to present the scope and solutions of issues related to the integration, modeling and participation of energy storage and DERs in the CAISO market." The rules will apply across the Western Energy Imbalance Market (EIM) but will not include EIM-specific items. At a session last fall, stakeholders pushed the ISO to expand the scope of the effort. (See *CAISO Urged to Broaden ESDER Phase 3*.)

The ISO has organized the proposal under the broad themes of demand response, multiple-use applications (MUAs) that allow storage to provide services and receive revenue from more than one entity at a time, and non-generator resources (NGRs). MUAs are getting more attention, with the California Public Utilities Commission in January passing a suite of 11 rules governing their use for storage.

The initiative includes exploration of new bidding and real-time dispatch options for DR and removal of a requirement that DR be aggregated under a single load-serving entity. It will also explore a process for facilitating market participation for NGRs, including identifying commitment costs. Also under development is a load-shift product for behind-the-meter storage, and a methodology to measure load curtailment from electric vehicle supply equipment, which is seen as a way to absorb excess output from renewables. (See *CAISO Load-Shifting Product to Target Energy Storage*.)

Currently, a DR resource that includes EV supply equipment is measured without considering the equipment's effect on load dynamics. One of many complex tasks confronting the ISO is determining how to meter the data to measure the performance of EV infrastructure, according to a CAISO presentation.

The initiative's previous phase, ESDER 2, is being prepared for submission to FERC after being approved by the CAISO Board of Governors last July. (See *New CAISO Rules Spell Increased DER Role*.) ESDER 2 included a set of alternative energy usage baselines to assess the performance of proxy demand resources, which are DER aggregations of retail customers. It also set out new rules that distinguish between charging energy and station power for storage resources, and established a net benefits test for DR resources that participate in the EIM.

Kim said the ISO will host more ESDER 3 working groups. Thursday's participants included EV charging station company eMotorWerks, California Energy Storage Alliance, DER and DR companies, utilities and others.

CAISO NEWS

FERC ALJ Certifies Calpine RMR Settlements

By Jason Fordney

Metcalf Energy Center

CAISO, Pacific Gas and Electric, and Calpine have settled their differences over the terms of the reliability-must-run agreements keeping three Calpine gas-fired plants operating instead of retiring.

FERC is likely to issue a decision on the agreements by April 30, Administrative Law Judge H. Peter Young said last week after certifying the uncontested settlements that would reduce the annual revenue the plants receive. The controversial out-of-market RMR payments are opposed by the California Public Utilities Commission and were reluctantly approved by the CAISO Board of Governors in November. (See *Board Decisions Highlight CAISO Market Problems*.)

The new settlements filed March 21 cover two different FERC dockets, one Calpine's Metcalf plant (ER18-240), and another for the company's Feather River and Yuba City plants in Northern California (ER18-230).

"In general, the offer of settlement would substantially reduce Metcalf's RMR service rates and would change the MEC facility's operating status," Young said of the Metcalf settlement. (See *FERC Orders Hearing, Settlement Talks for Calpine RMRs*.)

The Metcalf settlement would reduce the plant's annual fixed revenue requirement to $43 million from about $72 million through 2020 if it retains its RMR status, and make the plant operator responsible for routine repairs and capital expenses. It would set recovery for planned 2018 capital items to $8 million, to be recovered in 12 installments of $675,000 beginning on Jan. 1, 2018.

If the RMR agreement is extended, capital recovery would remain at about $8 million per year. The settlement would also grant the plant $8 million in 2019 and 2020 if the revised agreement is not renewed and the unit shuts down.

The settlements would also take all three plants from Condition 2 (eligible for full cost-of-service payments) to Condition 1 (eligible for only a portion of their revenue requirement) status, and impose a must-offer requirement, which the ISO's Department of Market Monitoring has recommended for all RMR units. CAISO is working to revise its RMR program to establish a must-offer requirement for resources. (See *CAISO, Stakeholders Debate RMR Revisions*.)

Yuba City

The Feather River and Yuba City settlements would reduce each plants' 2018 revenue to about $3.5 million from the previous $4.4 million, with a 2% hike for 2019 and 2020 if the RMRs are renewed. They would also impose a must-offer requirement on the plants.

After CAISO approved the RMRs last November, the CPUC issued an order directing PG&E to use energy storage to meet the needs currently served by the plants. (See *CPUC Retires Diablo Canyon, Replaces Calpine RMRs* and *CPUC Targets CAISO's Calpine RMRs*.) The storage resources must be online before 2019.

CAISO News

PG&E to Seek Storage, EE to Replace Dynegy Plant

By Jason Fordney

Pacific Gas and Electric is requesting proposals for the development of up to 45 MW of "clean energy" resources including at least 10 MW of energy storage, as the centerpiece of its plans to replace the aging Dynegy Oakland jet fuel-fired power plant.

The utility said it will open a two-month request for offers process in spring, inviting "innovative and competitive solutions for the portfolio." It hopes to bring the new mix of resources online in mid-2022; the procurement total will depend on the exact resource mix, the company said.

The 165-MW Dynegy plant currently operates under a CAISO reliability-must-run contract to meet local reliability needs.

CAISO identified PG&E's proposal, the Oakland Clean Energy Initiative, as a preferred solution in its 2017/18 transmission plan approved by the Board of Governors last week. (See *CAISO Moves Ahead With Market Changes*.)

The plan includes:

- transmission line rerates and system upgrades to remove limiting elements;
- at least 10 MW of four-hour, utility-owned, in-front-of-the-meter storage in the Oakland C and Oakland L 115-kV substation pocket;
- competitive procurement of 10 to 24 MW of "preferred resources" — energy efficiency, demand response, renewable generation and storage — in the substation pocket, at least 19.2 MW of which is "load modifying in nature";
- continuing to rely on transferring Alameda Municipal Power load from Cartwright (north) to Jenny (south) during peak load conditions and after an N-1 contingency, in preparation for an N-1-1.

The project marks the first time that clean energy resources would be deployed as an alternative to fossil fuels for transmission reliability in the PG&E area. It will be working with local community choice aggregator East Bay Community Energy to determine the clean energy and reliability solution.

"PG&E and the system operator worked collaboratively over the last several transmission planning cycles to study how distributed clean energy resources could become part of the solution," the company said in a news release. The utility said it will seek cost recovery for the battery storage facility from FERC and for distributed energy resources from the California Public Utilities Commission. It expects to file with the PUC by the end of the year.

Since 2010, CAISO has increasingly focused on non-transmission alternatives in its planning. The ISO cannot specifically approve non-transmission alternatives part of its annual plan, but it can identify them as preferred solutions, as it did with the PG&E proposal.

CAISO's transmission plan said the closing of the 40-year-old generator would cause thermal overloads on the Oakland 115-kV system without new local generation. The estimated cost of the PG&E proposal is about $102 million (2022 dollars), while other alternatives, including transmission lines and generation, range from $367 million to $574 million.

The Dynegy plant's RMR agreement with CAISO was renewed in September 2017, based on local reliability analysis. The ISO said that based on real-time operations data for 2015 and 2016, there is a need for at least 98 MW for a one-in-three heat-wave scenario that would cause heavy loads. It also cited instances where all three 55-MW Oakland units were running for local reliability. A 2018 forecast showed a need of 56 MW because of a discrepancy in substation load forecast distribution that the ISO said it would work with PG&E to correct.

ERCOT NEWS

Hailed for Compassion, Marquez Seeks New 'Chaos'

By Tom Kleckner

AUSTIN, Texas — The Public Utility Commission's open meeting last week was the last for Commissioner Brandy Marty Marquez, who announced March 8 that she is resigning from the commission after five years of service.

PUC Chair DeAnn Walker, who has known Marquez for many years, opened the meeting with words of praise for her good friend. Walker cited her loyalty, wit, tenacity and compassion. And her tears.

"She joked about it, maybe having a tear here and there on some cases," Walker said of Marquez. "Some people saw that as a weakness, but I saw that as one of her strengths. She was compassionate, but she always ruled on laws and facts."

"They make fun of me for being a crier over here," Marquez said during an interview earlier, in which she noted the differences between the political arena, where she spent 17 years, and the regulatory world. Marquez frequently referred to "here" and "there," nodding over her shoulder to the Texas State Capitol visible through her office window.

"Over at the Capitol, I think I got choked up twice," Marquez said. "I think I've grown a heart over here, which is probably difficult for people who are not in this industry to understand. But when you're dealing with the kinds of things we deal with here, it's pretty cool to be a part of it."

The senior member of the commission, Marquez said she was resigning to return to the private sector. (See Marquez to Depart Texas PUC.) Two weeks later, she said she doesn't "exactly know what's next yet."

Marquez said she's "led a very blessed life" in that she chooses a path and "something will go horribly wrong."

"Then I kind of throw it up in the air, and then something I never would have dreamed could happen to me will happen to me. This is kind of a reoccurring theme in my life."

Such was the case in 2013, when Marquez was Gov. Rick Perry's chief of staff as the state's legislative session came to an end.

Brandy Marty Marquez | © *RTO Insider*

"I'm a believer that when you feel the whisper of, 'It's time to think about doing something else,' you should honor it, because the whispers eventually become a shout and then a yell," Marquez said. "I knew I needed to leave Gov. Perry's office. I had worked for him for several years, but I had no idea what I wanted to do."

Unexpectedly, Perry asked Marquez if she would serve on the PUC. She agreed.

"It was perfect," she recalled of the switch. "It's been wonderful."

Marquez first had to acclimate herself to the regulatory pace. At the Capitol, she said, "You have five minutes to make a decision. Things are happening so quickly over there. This bill is up. Does it do this? What's the answer?

"In the regulatory world … you take your time to get more information," Marquez said. "If you're unsure, it's OK. There'll be more time. Over there, you're constantly thinking about the political angle. They don't want you to be political here. They want you to just look at the problem and solve it."

At the Capitol, the political crowd is always looking for a "seam," Marquez said. If a lawmaker's bill gets shot down, they look for someone else's bill that might work. If that bill doesn't work, they look for another.

"In the regulatory world, there are no seams. There are well-plotted streets and sidewalks, and maybe if you want to get crazy, you can get off the street and get on the sidewalk. You have to have that very prescribed predictability, because you can't ask people to invest billions and not know the rules of the game."

A San Antonio native, Marquez earned her undergraduate degree from the University of Texas at Austin and her law degree from St. Mary's University in her hometown. She calls herself a "child of chaos" who grew up in the Capitol, working first as an intern while also going through law school. Marquez served in numerous leadership positions on Perry's staff, including as his budget director, his policy director during his successful 2010 gubernatorial campaign and as his chief of staff during Texas' 83rd legislative session.

Marquez joined the PUC during the summer of 2013, reuniting with fellow Perry administration veterans Donna Nelson and Ken Anderson. It was a turbulent time, Marquez said, with a severe drought driving concerns over ERCOT's resource adequacy.

Within a year, Energy Future Holdings, a group of private equity firms that acquired Texas energy firm TXU in a 2007 leveraged buyout, declared bankruptcy. The PUC would be consumed with protecting the state's ratepayers from EFH's financial travails during attempts by several companies to acquire its Oncor utility. California's Sempra Energy finally earned the golden ring earlier this year. (See Texas PUC OKs Sempra-Oncor Deal, LP&L Transfer.)

A similar concern for ratepayers drove the PUC to push Oncor and Sharyland Utilities to swap customers and assets, relieving Sharyland's ratepayers of some of the highest rates in the state. (See Texas PUC OKs Settlement in Oncor-Sharyland Asset Swap.)

Marquez singles out both Oncor proceedings as the proudest accomplishments during her tenure at the commission.

"[Sharyland's] ratepayers were in a lot of pain out there. It became very important for me to find some kind of resolution, so people weren't having to live in fear of their

Continued on page 7

ERCOT News

Texas PUC Conditionally Approves Vistra-Dynegy Merger

The Public Utility Commission of Texas last week conditionally approved Vistra Energy's $1.7 billion acquisition of Dynegy, allowing the combined company to avert a requirement that it divest generation over market power concerns (Docket No. 47801).

Left to right: Commissioners Brandy Marty Marquez, Chair DeAnn Walker and Arthur D'Andrea share a laugh before the open meeting begins.

The commission amended staff's proposed order by excluding 820 MW of DC tie import capacity from the Eastern Interconnection as "not being appropriate" in determining the combined entity's market share. Combined with a previous ruling that excluded a 915-MW gas plant from market power calculations, Vistra's generation arm, Luminant, would no longer be required to divest itself of at least 1,281 MW of capacity.

PUC staff in February had recommended the divestiture to keep post-merger Vistra below the statutory cap of 20% of ERCOT installed capacity. (See *Vistra Balks at Divesting 1,281 MW in Dynegy Merger*.) Staff's proposed order excluded Luminant's Lake Hubbard power plant from the calculations based on its grandfathered exemption in a previous docket (No. 45429).

PUC Chair DeAnn Walker and Commissioner Arthur D'Andrea both filed memos in the proceeding, with Walker agreeing to D'Andrea's more substantive changes during the March 28 open meeting.

With the modifications, the order now says Vistra and Dynegy have met the requirements for approval "by demonstrating that the proposed transaction will not result in the combined ownership and control of more than 20% of the installed generation capacity located in or capable of delivering electricity to ERCOT."

Staff had said that Dynegy owns 820 MW of generation in the Eastern Interconnection "capable of delivering electricity to ERCOT" and recommended that capacity should be included in the calculation. D'Andrea countered by saying the DC ties should be treated as an exception, "not as a natural extension of the ERCOT market."

"I like the idea of saying that doesn't count as our market," he said.

With the changes, Luminant would no longer have to go through with the prospective sale of up to three gas plants, whose suitors include a trading firm.

"If you look at those three plants, I think I trust Vistra with them," D'Andrea said. "Would you rather Vistra, who you know and with a ton of skin in the game, run those three plants this summer, or would

Continued on page 8

Hailed for Compassion, Marquez Seeks New 'Chaos'

Continued from page 6

utility bill," she said.

Marquez said she gained a deep appreciation for utility workers after visiting South Texas to see the restoration efforts following Harvey's devastating blow to the Texas Gulf Coast last August.

"It's an industry where when the rain is pouring down, [the workers] go out. In Houston, they wade in water up to their waist, and in South Texas, they're in mud up to their knees. It's very inspiring what these folks do to ensure we have the quality of life we have in this country."

Marquez also had praise for the "problem-solvers" at the PUC — the staff, which she said provides a soft landing spot as the governor's appointees cycle through. "They tell you, 'Here's what's going on here. Don't be afraid, we've got you,'" Marquez said. "We have a very good continuity plan, because we have a very good staff here."

During last week's open meeting, Walker noted that for the first time since 2008, official portraits of the current commissioners hang underneath the PUC's logo on the meeting room's wall. (Nelson did not allow her picture to be hung until just before she left last May).

"We'll have three pictures up for one week. It's your fault that we're going back to two," Walker said, teasingly.

Asked if she has any regrets about her decision, Marquez told *RTO Insider* that she leaves the PUC in good hands with Walker and Arthur D'Andrea, who replaced Nelson and Anderson, respectively, last fall.

"It's a natural conclusion of a lot of things. It was the new energy of people who I could not think more highly of," she said. "I just feel like it's in a good spot, it's an OK time for me to spring forward and see what kind of chaos I can get into."

ERCOT NEWS

Texas PUC Conditionally Approves Vistra-Dynegy Merger

Continued from page 7

you rather a trader run those three plants this summer?"

Luminant assuaged the commission by committing that they would not import power over the DC ties. "That commitment is legally binding and enforceable through the coercive power of the state," D'Andrea wrote in his memo. "To my eyes, that makes the applicants 'incapable' of importing power."

The commission added language requiring the combined entity to annually file an affidavit, "under penalty of perjury, attesting to compliance" with the commitment not to import.

Walker said she was concerned other applicants could make the same commitment in future cases. "If we're expecting ERCOT to police this, I'm worried about the workload on [the ISO]."

"We're mostly dealing with really big players with a lot of skin in the game," D'Andrea said, noting ERCOT's Independent Market Monitor "can go after them."

"If [the IMM] finds something, they'll violate their agreement, and that's a pretty serious thing. That's something we don't take lightly," he said.

Vistra announced its intention to acquire Dynegy in October. The all-stock deal will create a generation and retail company owning 40 GW of capacity and serving nearly 3 million customers, mainly in ERCOT, PJM and ISO-NE. (See *Vistra Energy Swallowing Dynegy in $1.7B Deal*.)

Vistra said the transaction remains on track to close by July. It is only waiting on FERC approval, having obtained all other necessary regulatory approvals, including that of the New York Public Service Commission. Vistra's shareholders approved the merger in an early-March vote.

ERCOT Directors' Elections Approved

The commission's consent agenda included the approval of Terry J. Bulger's election (Docket No. 47916) and Peter Cramton's re-election (Docket No. 47915) as unaffiliated directors on ERCOT's board.

Bulger, a 35-year banking professional with ABN AMRO and Bank of Montreal, fills the vacancy created by Jorge Bermudez's resignation in 2016. His term will begin in April's board meeting.

Cramton, an economics professor at the University of Maryland College Park and the University of Cologne, will begin a second three-year term on Aug. 17.

Both directors were elected during ERCOT's annual membership meeting in December.

— Tom Kleckner

ISO-NE News

Mystic Closure Notice Leaves Room for Reversal

By Michael Kuser

Mystic Generating Station

Exelon on Thursday filed with ISO-NE to retire its 1,998-MW Mystic Generating Station in 2022, but the company said it “may reconsider” the decision if the grid operator can reform its markets to properly value the plant’s contributions to reliability and regional fuel security.

The Everett, Mass., facility includes a 576-MW dual-fuel unit (Unit 7); two gas-fired units capable of producing a combined 1,414 MW (Units 8 and 9); and Mystic Jet, an 8.6-MW oil-fired peaker.

“Changes to market rules are necessary because critical units to the region, like Mystic 8 and 9, cannot recover future operating costs, including the cost of securing fuel,” Exelon said in a statement.

Absent regulatory reforms, “these units will not participate in the Forward Capacity Auction scheduled for February 2019,” Exelon said in a statement.

ISO-NE spokeswoman Marcia Blomberg told *RTO Insider* that Mystic is “one of the two largest generating stations on the regional power system. The ISO will conduct a study to ascertain how these retirements could affect power system reliability and will release the results as soon as possible.”

Exelon Power President Ron DeGregorio said it was “a difficult day not only for the talented men and women who have dedicated themselves to operating Mystic safely and reliably every day, but also for their families, their communities and all of their colleagues here at Exelon.”

Cost Recovery

Exelon’s announcement referred to a recent statement by the RTO that it “may propose interim and long-term market rule changes to address system resiliency in light of significant reliability risks” identified in its January 2018 fuel security report. (See *Report: Fuel Security Key Risk for New England Grid*.)

“To the extent that changes are timely filed and approved by the Federal Energy Regulatory Commission, Exelon Generation may reconsider the retirement of the Mystic units,” the company said.

FERC in September 2017 approved Exelon’s request for recovery of more than $1.5 million in fuel costs for the plant

Continued on page 10

ISO-NE News

Massachusetts Bids Adieu to Northern Pass

By Michael Kuser

Massachusetts on Wednesday revoked its selection of Northern Pass as the sole winner of a massive clean energy solicitation, saying it will instead enter contract negotiations with the rival New England Clean Energy Connect (NECEC) project.

The decision capped a tumultuous two months since the state chose Northern Pass in its MA 83D solicitation for 9.45 TWh per year of hydro and Class I renewables (wind, solar or energy storage). The joint project between Eversource Energy and Hydro-Quebec won the contract Jan. 25, only to see the New Hampshire Site Evaluation Committee (SEC) unanimously reject the 1,090-MW transmission line a week later. (See *New Hampshire Rejects Permit for Northern Pass*.)

Eversource said it understood why Massachusetts needed to move on with its clean energy plans but that "despite recent delays, we continue to believe that Northern Pass is the best project for the region and New Hampshire, and we intend to pursue all options for making it a reality."

The company had appealed the New Hampshire decision, but the SEC voted March 12 to wait until its permit denial is published later this month before considering the appeal, effectively killing the 192-mile HVDC line's chance to meet Massachusetts' March 27 contract deadline. Any contract awarded under the request for proposals must be submitted to the state's Department of Public Utilities by April 25.

The Massachusetts committee charged with reviewing proposals selected the NECEC as an alternative to Northern Pass. (See *Mass. Picks Avangrid Project as Northern Pass Backup*.) The committee consists of representatives from the state's Department of Energy Resources and distribution utilities Eversource, National Grid and Unitil.

Central Maine Power, an Avangrid subsidiary, partnered with Hydro-Quebec on NECEC, a 145-mile transmission line that would deliver up to 1,200 MW of Canadian hydropower to the New England grid. The partners estimate the project will cost $950 million.

No Free Pass for NECEC

Massachusetts Sierra Club Director Emily Norton on Wednesday lauded the rejection of Northern Pass as "good news," saying the project "would have increased electricity costs in the state, destroyed pristine wilderness in New Hampshire and continued the destruction of traditional hunting and fishing grounds of First Nations in Quebec, all while failing to reduce climate pollution in the region."

During a three-day hearing in February, New Hampshire's SEC voted 7-0 to reject Northern Pass after expressing concerns that it would harm property values, tourism and land use.

Testifying on behalf of the city of Concord, N.H., during the hearing, wetlands scientist Rick Van de Poll said that the project's temporary and permanent impacts to wetlands in the city would be significantly greater than the developers assumed in their October 2015 wetlands permit application.

Van de Poll said permanent impacts would include reduced habitat fish and aquatic life habitat; loss of habitat for rare and endangered species; and reduced scenic quality, flood storage and groundwater recharge.

But NECEC is not getting a free pass from environmentalists and other industry stakeholders. New Hampshire Sierra Club Director Catherine Corkery joined Norton in saying, "It is too soon to celebrate, however." NECEC "carries many of the same problems as Northern Pass."

"MA has gone from the fatally flawed Northern Pass to the nascent NECEC, which doesn't have any permits," New England Power Generators Association President Dan Dolan tweeted. "If the original goal was to meet 2020 climate targets, that's now out the window. All while leading to potentially the largest electric rate increase in state history."

Three top generators in Maine are already contesting the NECEC. Calpine, Dynegy and Bucksport Generation, which together own one-third of the state's installed electric generating capacity, have asked the Public Utilities Commission to allow them to intervene late as full parties in the proceeding to review the project. (See *Generators Challenge HVDC Line at Maine PUC*.)

Mystic Closure Notice Leaves Room for Reversal

Continued from page 9

(ER17-933). The commission granted Exelon more than $1.5 million for Unit 8 and 9 fuel costs that were not recovered because of market power mitigation measures applied in October and November 2016. (See *FERC Approves Cost Recovery for Exelon's Mystic Plant*.)

Fuel Security and LNG

Oil supplies at plants in New England declined rapidly during a cold snap earlier this winter as gas prices spiked and dual-fuel plants switched to oil, but the RTO avoided serious reliability issues thanks to LNG shipments.

Contributions from other types of generators were crucial during the cold snap, according to the RTO's analysis.

"For instance, electricity produced by the Millstone nuclear station during the cold spell is equivalent to what could be produced by about 880,000 barrels of oil, and the power from the Mystic 8 and 9 units in Boston, which are fueled by LNG from the nearby Distrigas import facility, was the equivalent of more than 360,000 barrels of oil," ISO-NE CEO Gordon van Welie said in February. (See *Van Welie: ISO-NE in 'Race' to Replace Retirements*.)

Exelon also announced Thursday it will purchase the Everett Marine Terminal, an LNG import facility, from ENGIE North America "to ensure the continued reliable supply of fuel to Mystic Units 8 and 9 while they remain operating." No contract terms were disclosed.

The facility is the oldest such LNG facility in the U.S. and has connections with two interstate pipeline systems, the Tennessee and Algonquin pipelines, as well as with the local distribution system owned by National Grid.

ISO-NE NEWS

ALJ Rules New England Tx Owners' ROEs not Unjust

By Michael Kuser

A FERC administrative law judge ruled last week that municipal utilities and commission staff failed to prove that the New England Transmission Owners' (NETOs) base return on equity of 10.57% (11.74% with incentives) is unjust and unreasonable, rebuffing requests to reduce it.

The March 27 initial decision by ALJ Steven A. Glazer found that the discounted cash flow (DCF) analyses by the complainants — the Eastern Massachusetts Consumers-Owned Systems (EMCOS) — and FERC staff were "fatally defective" because they failed to include Algonquin Power & Utilities in their proxy groups, "despite this company's ample qualifications to be included" (EL16-64-002).

The EMCOS, whose case was supported by state regulators and industrial consumers, asked FERC in a April 2016 complaint to reduce the NETOs' base ROE to 8.93% or lower (11.24% with incentives). It was the fourth challenge since September 2011 to the ROE for the NETOs, which include Emera Maine, Northeast Utilities, Central Maine Power, National Grid and NextEra Energy. (See *FERC Denies New England Tx Owners ROE Rehearing*.)

The 2011 challenge resulted in FERC lowering the base ROE to 10.57% from 11.14% in 2014. But the ruling was vacated by the D.C. Circuit Court of Appeals last April, which found that the commission failed to prove the higher rate was unjust and unreasonable, as required before setting a new rate (*Emera Maine et al. v. FERC*). (See *Court Rejects FERC ROE Order for New England*.)

The commission has not responded to the court's remand.

Setting the Proxy Group

Glazer sided with the NETOs in ruling that the EMCOS' and staff's DCF analyses should have included Algonquin because the company pays dividends and operates within the contiguous U.S., and its credit ratings are within the "comparable risk band" for the NETOs. Glazer said FERC staff improperly rejected the company because it is headquartered in Canada and also broke with commission precedent in ignoring the credit ratings of the NETOs' parent companies.

The EMCOS' economist rejected Algonquin because it was not included in the Value Line Investment Survey and did not have a five-year Institutional Brokers Estimate System (IBES) earnings growth rate published in Yahoo Finance, the source of earnings growth forecasts used by the commission. IBES later added the company to its ratings; inclusion in the Value Line survey is not required by FERC, the judge said.

Including Algonquin's IBES-based ROE of 16.14% would significantly alter staff's and EMCOS' DCF analyses, making the current 10.57% base ROE within the zone of reasonableness, Glazer said.

"Their zones of reasonableness would shift upward from approximately 6 to 11% to approximately 7 to 16%, and the midpoint of their zones would shift from approximately 8.4% to approximately 11.8%," Glazer wrote.

Moving the Goalpost

The judge was particularly critical of the EMCOS' analysis, saying it contained "numerous errors and changed significantly throughout this proceeding," including on the last day of the hearing in the case. "Both the EMCOS and staff made several unwarranted changes to the commission's typical DCF analysis," he said. "In short, the goalpost was moved repeatedly by the EMCOS and staff to wherever the football was in order to score points."

Glazer said he did not need to determine a new ROE because of the inability of staff and the EMCOs to provide reliable analyses that proved the existing rates were not just and reasonable. "The failure of the EMCOS and the staff to meet their burden of proof means that the case is over, because they have produced no DCF analysis that is usable in this case for any purpose."

He also said that their failure also "renders moot the EMCOS' further argument that the base and maximum ROEs should be adjusted downward in order to mitigate alleged harm to consumers" caused by the NETOs' maintenance of equity–heavy capital structures.

Exceptions to the decision are due in 30 days, with objections to the exceptions due 20 days later. If no party objects, the ALJ's decision would take legal effect without further action by the commission.

That's unlikely, ClearView Energy Partners said in an analysis of the ruling, which predicted challenges to the inclusion of Algonquin.

Response to Remand

The analysts said FERC could respond to the D.C. Circuit's remand of the 2014 ruling by opening a Notice of Inquiry or by issuing a revised decision.

"If the remand proceedings ahead for the *Emera Maine* decision result in the FERC upholding the June 2014 revision of the ROE to 10.57%, then we expect the commission might also affirm the ALJ's finding here that the most recent complaint fails," the analysts wrote.

MISO News

Grid Resilience Consensus Eludes MISO Sectors

By Amanda Durish Cook

NEW ORLEANS — While MISO's various sectors last week voiced differences in their views of what constitutes grid resilience, they could agree on one thing: Its specific attributes are still difficult to pin down.

Resilience was in the spotlight after MISO stakeholders selected the subject as their quarterly "hot topic" industry discussion held before the RTO's Board of Directors on March 28.

Meeting participants offered a mixed bag of suggestions.

Minnesota Public Utilities Commissioner Matt Schuerger agreed with FERC's definition of resilience as the "ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to and/or rapidly recover from such an event."

But Schuerger said he sees a lot of overlap between reliability and resilience, making the latter largely covered by NERC's portfolio of standards.

Otter Tail Power's Stacie Hebert said some of MISO's transmission-owning members viewed resilience more narrowly as the ability of the system to recover from a failed state.

'Resilient Reliability'

MISO's Environmental sector is concerned about double-counting resilience as resource adequacy and reliability, said sector representative John Moore, director of the Natural Resources Defense Council's Sustainable FERC Project. He argued instead that there are degrees between "fragile reliability" and "resilient reliability."

"So much of what MISO already does in planning relates to resilience indirectly or directly," Moore said.

Coal- and oil-fired generators became comparatively economic during early January's cold snap because they had not been regularly run until emergency conditions nudged them "higher in the dispatch stack," he said. "They were the most expensive resources in the system until we needed all resources."

North Dakota Public Service Commissioner Julie Fedorchak said states may have to increasingly turn to MISO's markets to fulfill generation requirements as uneconomic units retire.

Alliant Energy's Mitchell Myhre said his Transmission-Dependent Utilities sector was trying to avoid being "too prescriptive" in defining resilience, a concept he called "hard to define."

Still, others saw a clearer distinction between resilience and reliability.

"My kids will never know what it's like to sit around with candles playing war games during a thunderstorm because the power is out. That just doesn't happen anymore. That's reliability," Wisconsin Public Service Commissioner Mike Huebsch said. Resilience goes further than that, entailing better communication between grid operators, utilities and customers when disruptions occur, he said.

MISO's sector representatives meet with the Advisory Committee. | © RTO Insider

MISO Already Managing Resilience

Multiple members said MISO already has processes in place to tackle resilience.

"We think MISO is resilient. It's always been part of our base business, even if we didn't call it resilience," said MISO Vice President of System Planning Jennifer Curran.

In response to FERC's call for RTO/ISO comments on resilience in early March, MISO reported no "imminent or immediate" concerns in its footprint and pointed out that its stakeholder processes and projects have been geared toward resilience "for nearly two decades." (See "MISO: Work Already in Progress," *RTO Resilience Filings Seek Time, More Gas Coordination*.)

"The resilience issue is broader than the transmission grid, and we all have a role to play in ensuring resilience," Curran told stakeholders.

Director Baljit Dail asked sectors what the RTO should do incrementally beyond what it already does.

"It seems to me that the bulk of the resilience issue is not at the MISO-level, but the distribution level, and that's not MISO's purview, but all of you sitting around this table," he told members.

Moore said MISO could expand cybersecurity measures, with which Dail agreed.

Kevin Murray, representing the Coalition of Midwest Transmission Customers and MISO's End-User Customers sector, pointed out that much of the RTO's cybersecurity efforts can only be discussed in closed-session meetings to avoid release of sensitive information.

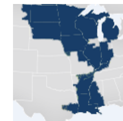
"I think one of the things that will be a challenge for us is sharing as much of that information as we can," board Chair Michael Curran agreed.

Director Todd Raba said it seems the distinctions between transmission and distribution systems are becoming increasingly blurred. He rhetorically asked if MISO and its members have to reorganize the metrics placed on each system.

Schueguer said it will be a state-by-state

Continued on page 13

MISO News



Steering Committee Ponders Expanded Role for MISO Storage Group

By Amanda Durish Cook

NEW ORLEANS — MISO's Steering Committee last week said it needs more time to decide whether the stakeholder-led Energy Storage Task Force can deliberate on how the RTO can comply with FERC's sweeping storage order issued in March.

Established last year, the task force was charged with exploring expanded storage participation in MISO, including generator-and-storage interconnection combinations and competitive bidding on storage projects that solve transmission issues. However, the task force has not assumed it could begin considering expanded storage rules as they specifically relate to last month's Order 841. (See *MISO Storage Task Force Talks Order 841*.)

MISO's task forces do not determine stakeholder policy; instead, they submit recommendations to other committees with decision-making authority, such as the Advisory Committee.

Tia Elliott | © *RTO Insider*

The Energy Storage Task Force has already sent several discussion topics — including storage capacity accreditation, must-offer requirements, state-of-charge management, possible aggregation and new modeling needs — to MISO's Resource Adequacy Subcommittee, Reliability Subcommittee, Planning Advisory Committee and Market Subcommittee.

"My initial response is that this task force was created prior to Order 841," Steering Committee Chair Tia Elliott said during a March 28 meeting.

Task force Chair John Fernandes said his group will have plenty of issues to discuss even if the committee decides against assigning it Order 841. The group can hold dialogue on operational functions, customer-owned storage assets and modeling issues — including whether storage should be modeled in MISO's yearly Transmission Expansion Plan process or the interconnection queue, he said.

"I don't necessarily have it in my mind that the task force will go away," Fernandes said.

As an interim measure, FERC last week approved a second MISO storage definition, allowing storage to participate in front of the meter to supply energy, capacity, spinning reserve, supplemental reserve and regulating reserve. (See *FERC OKs MISO Plan to Expand Storage*.) However, the commission also determined that MISO had to address other storage participation rules, namely creating unique bidding parameters for storage resources, a path for storage to receive make-whole payments and an outline detailing how storage could provide voltage support and black start services. It ordered the RTO to devise those rules in a compliance filing.

Grid Resilience Consensus Eludes MISO Sectors

Continued from page 12

choice to develop mandates to "harden" the distribution system.

'Accidental' Resilience

Independent Power Producers sector leader Barry Trayers said he thought MISO is heading toward resilience "almost accidentally" with increased distributed energy resources and a more diverse fuel mix.

"This movement towards DER should bolster the system because there's less risk of a single large contingency," said Director Thomas Rainwater.

The difference between the electrical recoveries from Hurricane Harvey in Texas and Hurricane Maria in Puerto Rico last year should help MISO and stakeholders define resilience attributes, Rainwater said. He pointed out that parts of Puerto Rico still don't have power six months after the storm.

Murray pointed out that during hurricanes last year in Florida, bucket trucks and lineman were already queuing up before they hit, readying restoration efforts.

Director Mark Johnson said MISO and its members will at some point have to identify a list of the likely low-probability, high-impact events that could occur in the 15 states in its footprint, as well as the Canadian province of Manitoba.

"The actions that need to be taken will be very much event-specific," Johnson said.

"There comes a point where maybe we put pen to paper or steel to ground," agreed Advisory Committee Chair Audrey Penner.

Studying Weather Events

End-Use Customers sector representative and Louisiana Public Service Commission counsel Katherine King said a better understanding of resilience will require MISO to conduct an in-depth investigation into its South region's two most recent maximum generation events: one last April after heavy outages and high temperatures, and another in mid-January triggered by extreme cold. (See "Several Factors in Spring MISO South Maximum Generation Event," *MISO Market Subcommittee Briefs* and *Louisiana Regulators Question MISO South Max Gen Event*.)

"I think it's very important to go back in after these events occur and ask what caused them and what we can do better," King said.

The Louisiana PSC is opening a docket and scheduling a technical conference to investigate the January maximum generation event, King added.

Mississippi Public Service Commissioner Brandon Presley said the RTO should also study contingency impacts on the 3,000-MW contract path connecting MISO Midwest and South.

"Everybody has an interest in that connection and woe be it on us if we ignore that," Presley said.

Rainwater said any changes made in the name of resilience must be cost-effective.

"At the end of the day, the end-use customers will have to pay for whatever resiliency measures we deem necessary, and we have to keep that in mind. We cannot build the system to protect it from … interruptions of any kind," Rainwater said.

MISO NEWS

MISO Markets Committee Talks Winter, Spring — and Beyond

By Amanda Durish Cook

The Markets Committee of the Board of Directors meets. | © *RTO Insider*

NEW ORLEANS — A seasonal post-mortem at MISO's Board Week provided stakeholders with insight into the RTO's market performance during the near past, near future — and beyond.

MISO and its Independent Market Monitor agreed that markets generally performed well during a challenging winter, and the RTO predicts more operational efficiency throughout spring. But it foresees considerable market changes over the next decade.

The RTO said the sustained cold snap that opened the year was "managed nearly routinely by MISO and members."

Executive Director of Strategy Shawn McFarlane said the RTO's $31/MWh December-February average energy price was about 10% higher than last winter.

MISO's winter peak of 106.1 GW, set on Jan. 17, was 3.2 GW lower than its all-time winter peak set in January 2014. Loads exceeded 100 GW for the first five days of 2018, with forced and planned outages reaching 36 GW. (See *MISO Breaks down Recent Cold Snap*.)

"While it wasn't routine, it was handled quite routinely — not a lot of excitement," McFarlane said during a March 27 meeting of the Markets Committee of the Board of Directors.

MISO committed one unnecessary unit on Jan. 1, an inefficient outcome in what was an otherwise more efficient performance when compared to 2014's polar vortex weather event.

David Patton | © *RTO Insider*

However, MISO said a brief mid-January cold spell concentrated in MISO South "proved more challenging, but reliability maintained." During his quarterly report, Monitor David Patton agreed that mid-January generation patterns "were more fascinating."

In that instance, another round of arctic air pushed loads above 106 GW over Jan. 17-18, and MISO South set a new winter peak of 32.1 GW in the face of record low temperatures in the region. (See *Louisiana Regulators Question MISO South Max Gen Event*.) MISO was forced to call a maximum generation event in the South region Jan. 17 after outages there hit 17 GW.

McFarlane said MISO South's icy weather froze the region's water and air lines, which are not nearly as insulated as in MISO Midwest. The RTO compensated for South's shortfall with generation from Midwest, at one point flowing just over 3,000 MW — the maximum allowed by the MISO-SPP agreement — along the contract path between the regions.

"The [South] generators just aren't as prepared for freezing temperatures," Patton said. "Part of the reason we were in such bad shape is because the forced outages kept growing and growing. … This is about the most stressful situation I can imagine for MISO South."

Patton said if MISO had not made emergency power purchases for the South on Jan. 17, regional supply would have dipped below load for about three to four hours. He referred to the "lights going out in MISO South."

But Director Michael Curran immediately rebuked Patton's use of such dramatic language, while also responding that MISO should "burn down" SPP's transmission on the contract path before it allows MISO South to shed load.

Patton said the situation highlights the need to create a regional capacity reserve product that can be delivered within 30 minutes, a recommendation he repeated from last year's State of the Market report. He also said MISO's emergency prices are still too low because its extended locational marginal pricing (ELMP) does not properly account for regional dispatch transfer flows. Accounting for such flows in ELMP would be an easy fix, he added.

Spring

Executive Director of System Operations Renuka Chatterjee reiterated a previous report of MISO's spring preparedness but noted that volatile spring weather can "break load patterns."

MISO staff said earlier in March that the RTO faces a small possibility of spring emergency conditions if either loads or forced outages are higher than normal. (See *Outages Small Risk for MISO Spring Operations*.)

Director Thomas Rainwater asked if the outage risk comes from large, thermal units whose loss "MISO has to scramble to replace."

"Yes, it's obviously the 1,000-MW units," Chatterjee replied.

She said as little as an additional 2 GW in forced outages over forecasted load could

Continued on page 15

MISO News

Board of Directors Briefs

Chairman Honors Late Board Member

Eugene Zeltmann | *Beloit College*

NEW ORLEANS — MISO Board of Directors Chairman Michael Curran paid tribute to Eugene Zeltmann, a former board member who passed away in late February after a battle with leukemia.

Zeltmann was a former CEO of the New York Power Authority and served on several boards after his retirement from that position in 2006. He served a nine-year tenure on MISO's board, exiting in 2015.

"He served with considerable distinction and was a moral compass to us all," Curran said during a March 29 board meeting.

After struggling to compose himself, Curran disclosed that he visited Zeltmann two weeks before he died and found the same man he served with on MISO's board.

"'Tell me about MISO, Michael. Tell me how everyone is doing,' he said. He was Gene until the end," Curran said.

RTO Adds 8 New Members

Michael Curran | *© RTO Insider*

MISO can add eight new non-transmission-owning entities to its membership in 2018, board members decided Thursday.

Senior Vice President of Compliance Services Stephen Kozey said five of the eight applicants will join MISO's Competitive Transmission Developers stakeholder group: Avangrid Networks, Cardinal Point Electric, Eastex Transco, Ferrovial Transco International UK and LS Power Midcontinent.

MISO is also adding the city of Benton, Ark.'s Benton Utilities as a participant in the Municipal, Cooperative Electric Utilities and Transmission-Dependent Utilities sector, and Ranger Power and Tradewind Energy to the Independent Power Producers sector.

Election Year for MISO

MISO will also hold board elections later this year to fill three board seats.

Directors Phyllis Currie's and Mark Johnson's first terms are ending, and both are seeking re-election. Curran will reach the RTO's limit of three three-year terms at the end of this year and will not be eligible for re-election.

MISO will use an outside search firm to produce a slate of outside candidates to be vetted by the RTO's Nominating Committee (composed of stakeholders), board members and staff through summer.

— Amanda Durish Cook

MISO Markets Committee Talks Past, Present, Future

Continued from page 14

force MISO to call upon reserves this spring.

"We've seen a chance in the last couple of years of tight operating conditions in the shoulder seasons," Chatterjee said. "[Reserves] are the end of our stack, and we'll get into those if we have to."

However, Chatterjee reassured the board that MISO faces a very slim chance of spring load shedding.

Patton said he now recommends that some generators take planned outages during winter rather than spring to lessen the impacts of mass outages in shoulder periods.

Beyond

With winter and spring covered, a MISO executive outlined a rough to-do list to design a market for a future grid that includes renewables, storage and smart devices.

Richard Doying, now head of future market design, delivered to the board the first report of his exploratory-style role. (See "MISO Shuffles Leadership," *MISO Informational Forum Briefs: Jan. 23, 2018*.)

"MISO will be operating transmission with very different assets in the future," he said.

Doying and MISO staff are evaluating what changes are needed to incorporate renewables, distributed energy supply and storage, and digital flow control devices such as smart appliances and thermostats. MISO will complete an analysis of market, operational and planning impacts, and prepare a report by the first quarter of 2019, he said.

"Software cycle time really drives digitalization. When you think about an app on your phone that you can install today that wasn't available yesterday — that took just a few weeks for someone to develop," Doying said.

Digitalization will affect the grid much more than owners and operators may realize. "Although we can't see when the changes will arrive, we know that they are coming," he said. "Waiting until they arrive is a problem and will be imprudent."

MISO must address, for instance, windy nights when LMPs fall to negative values, a situation that becomes unworkable for non-wind generators serving load. He also said the RTO's market team will investigate how to properly value essential reliability services.

Director Baljit Dail asked what MISO's version of California's "duck curve" may look like.

Doying responded that MISO is investigating a "double up" of its renewable sources in the next 10 to 15 years, as indicated by new entrants to the queue, but he didn't elaborate on specific demand curve shapes.

"This is an exciting, but scary, pallet of issues," said Director Barbara Krumsiek.

Rainwater asked how MISO will begin to value other attributes in a system designed around cost-based ratemaking.

Doying did not get into specifics, but he said that "pricing will be a critical element of any reforms."

MISO News

Advisory Committee Steps up Criticism of MISO Forecast Plan

By Amanda Durish Cook

NEW ORLEANS — MISO Advisory Committee members last week criticized the RTO's plan to revamp load forecasting using projections from load-serving entities, saying the amount of data needed is nearly impossible to provide.

Speaking at a March 28 Advisory Committee meeting, Planning Advisory Committee Chair Cynthia Crane said that while MISO must revise its independent load forecast to accommodate growth of distributed resources and changing load shapes, the RTO's 140-plus LSEs have concerns over how to provide four 20-year forward forecasts using four sets of future assumptions from the Transmission Expansion Plan.

"If you do the math, you're talking 98 million data points, and there's the question of how MISO is going to organize all of that," Crane said, using a calculation of 8,760 hours per year for 20 years across the four MTEP futures.

Wisconsin Public Service's Chris Plante said he wasn't convinced that MISO needs that level of detail for transmission planning.

Megan Wisersky and Chris Plante | © *RTO Insider*

"I started my utility life out as a load forecaster. ... If I could forecast 8,760 hours for 20 years over four futures, I wouldn't be in this room," joked Madison Gas and Electric's Megan Wisersky. "When I'm told this will improve the planning process, I just laugh," adding that she doubted that current third-party load forecaster Purdue University provides the same level of detail.

"We're not going to add staff for such a meaningless exercise," Wisersky said of her fellow LSEs.

MISO has said it might replace its current independent load forecast prepared by Purdue's State Utility Forecasting Group with data compiled by LSEs to produce the forecast that informs transmission planning, an effort that will require LSEs to annually assemble four different 20-year load forecasts to fit with each MTEP future. The approach is one of two MISO is vetting to improve its load forecasts. If LSEs decide they cannot collect that level of information, the RTO will continue its practice of hiring a contractor to put together a load forecast. (See *Members Skeptical as MISO Explores LSE Load Forecasting*.)

Plante said it's difficult for members to make an informed decision until stakeholders know how much MISO pays Purdue for its independent load forecast. He wondered if the alternative plan would save the RTO any money.

"We see this as an opportunity to try to offset some of these increases we see in the [operations and maintenance] budget year to year," he said.

Crane pointed out that all other RTOs use an independent load forecast to guide transmission planning.

"I'll sound like my mother here: Just because someone else is doing it, doesn't mean you should," Wisersky said.

MISO staff did not provide comment at the meeting, although Executive Director of System Planning Aubrey Johnson took notes on the members' reactions and promised to deliver a report to RTO planners.

MISO News

MISO to Focus on Shoring up Existing Market Platform

By Amanda Durish Cook

NEW ORLEANS — MISO's dedicated market platform replacement team will work this year to ensure the RTO's existing system can stay afloat during the time it will take to build the new one, staff told stakeholders last week.

While MISO is slated to begin naming specific requirements and assembling the new platform next year, this year's efforts will focus on "standing up" the existing platform for day-to-day operations with software patches, Executive Director of Market Development Jeff Bladen told the Technology Committee of the Board of Directors on March 27.

The RTO has so far filled 18 of the 30 positions it has planned for this year, including market engineers and a software architect, Bladen said.

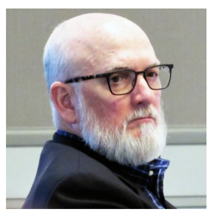
In 2017, MISO completed an assessment on the capability of its existing market platform and began early design of the new, more adaptable modular system. The RTO is poised to spend $130 million by 2024 to replace the aging system. It expects to begin migrating to the new system in 2020, keeping the current one in operation at least until 2021. (See *MISO Makes Case for $130M Market Platform Upgrade*.)

"This will be one of the largest undertakings in our history," Bladen said.

"We're making sure we build the right kind of system, not just an enhanced version of the current system," MISO Director of Forward Operations Planning Kevin Sherd told stakeholders at a March Market Subcommittee meeting.

'No BS'

With such a complex project, MISO's directors urged that executives deliver clearer reports that do not minimize any future hitches or budget overflows.



Thomas Rainwater | © *RTO Insider*

"What I want to hear from you is clear, candid communication. No BS. No flowery language. … That's the kind of stuff that I need to hear," Director Thomas Rainwater told MISO executives.

Baljit Dail (left) and Michael Curran | © *RTO Insider*

"That's what we need: full transparency and candor. We're not going to rip your heads off," Director Baljit Dail added.

Earlier in March, Bladen said MISO's new platform will be equipped to handle expanded energy storage participation under FERC's Order 841, but the legacy system may struggle to accommodate the directives.

Meanwhile, MISO's separate, settlements platform replacement is ready for the launch of five-minute settlements, officials said, although the RTO is continuing to test the new system while it waits for generation owners to adapt their own software and reporting systems to a five-minute schedule. MISO has twice obtained FERC approval to defer the five-minute settlements roll-out until July. (See *MISO Wins Delay on 5-Minute Settlement Roll-Out*.)

MISO Rule Change to Simplify Stakeholder Group Elections

NEW ORLEANS — A new rule change will prevent MISO participants from simultaneously running for chair and vice chair of a stakeholder group, a move that multiple stakeholders said was needed to simplify the nominating process.

The MISO Advisory Committee | © *RTO Insider*

MISO Advisory Committee sector representatives voted 19-5 in favor of the change during a March 28 meeting.

The RTO's Stakeholder Governance Guide was previously silent on whether stakeholders could submit their names as nominees for the chair and vice chair positions of a single stakeholder group.

"I think we assumed that stakeholders would not try for both," Advisory Committee Vice Chair Tia Elliott said.

However, two candidates running last year for chair of MISO's new Energy Storage Task Force expressed interest in running for vice chair if they weren't picked for the top position. The situation led to one candidate submitting a late vice chair nomination, ultimately forcing a rerun of the election. (See *Nomination Redux for MISO Energy Storage Task Force*.)

— Amanda Durish Cook

MISO NEWS

FERC OKs MISO's Doubled Offer Cap, Orders Alterations

By Amanda Durish Cook

FERC on Wednesday approved MISO's plan to permanently double its hard offer cap but told the RTO to clarify some details about the proposal in a compliance filing within 60 days (ER17-1570-001).

The proposal marked MISO's second attempt to comply with FERC Order 831, which required RTOs and ISOs to raise their hard caps for verified cost-based incremental energy offers to $2,000/MWh. The commission issued the order in response to the 2014 polar vortex, which sent natural gas prices soaring and left some generators unable to cover fuel costs.

FERC late last year rejected MISO's first attempt at complying with the rule, saying the RTO wrongly proposed a provision that prohibited resources from submitting cost-based offers above the required $2,000/MWh hard cap. (See *MISO's Plan for Wintertime Offer Caps Stalled by FERC*.)

The commission had also ruled that MISO:

- failed to describe what factors it would consider when verifying cost-based offers or distributing uplift;
- was silent on its treatment of external supply offers in excess of the cap;
- neglected to specify a verification process for demand response; and
- failed to limit the cap on all adders above cost to $100.

On Wednesday, FERC determined that MISO's second filing had cleared up the offer validation process, which gives the Independent Market Monitor discretion to validate market participants' data. The RTO additionally complied with a requirement that external energy transactions not exceed the hard cap but also not be subject to validation.

However, FERC said MISO still must pledge to apply the new hard cap to adjusted energy offers from fast-start resources.

The commission acknowledged that its previous ruling mistakenly understood "proxy offers" to include fast-start resources' adjusted offers, but it said it now recognizes the term applies to resources deployed during emergency operating procedures.

"The commission did not intend to change the definition of 'proxy offers,'" FERC said.

MISO had proposed to apply the $2,000/MWh hard cap to most proxy offers used during emergency conditions for price-setting purposes, but it said emergency demand response proxy offers would not be included. The RTO has long allowed emergency DR resources to exceed the hard price cap up to the value of lost load, which is currently $3,500/MWh.

FERC said it viewed MISO's value of lost load as an "administratively determined pricing mechanism beyond the scope of the offer cap reforms in Order No. 831."

The commission also accepted MISO's plan to have its Monitor verify offers from DR resources above the $1,000/MWh soft offer cap before market clearing in order to allow them to set the LMP. FERC also approved edited Tariff language that allows resources to submit cost-based incremental energy offers above $2,000/MWh and recover verified costs through make-whole payments, although such offers are barred from setting LMPs.

But the commission is requiring MISO to provide more detail on the Monitor's verification process for resources that submit incremental energy offers above $1,000/MWh that cannot be verified prior to the market clearing. FERC said MISO must also describe when the Monitor will verify the prices and revise reference levels, and when a market participant can dispute revenue sufficiency guarantee make-whole payments.

"Additionally, we direct MISO to propose Tariff language describing how the amount of the make-whole payment will be determined," FERC added.

FERC also ordered MISO to update its Tariff to include references to its Operating Cost Survey, which is used to determine reference levels by collecting more than 200 "pieces of data for a single plant," according to the RTO.

FERC additionally said MISO must clarify the use of its adder for "outage risk," a term the RTO used in its amended offer cap filing but is not found in Tariff provisions that define reference levels, which instead employs the term "legitimate risk."

FERC also said MISO appeared to violate a rule that limits to $100/MWh the sum of any adders for cost-based incremental energy offers above $1,000/MWh by allowing two types of adders within its offer cap: the legitimate risk adder and a fuel cost uncertainty adder. The commission gave the RTO 60 days to explain the differences, if any, between the two terms and describe how it will stay within the $100/MWh adder limit.

NYISO News

Management Committee Briefs

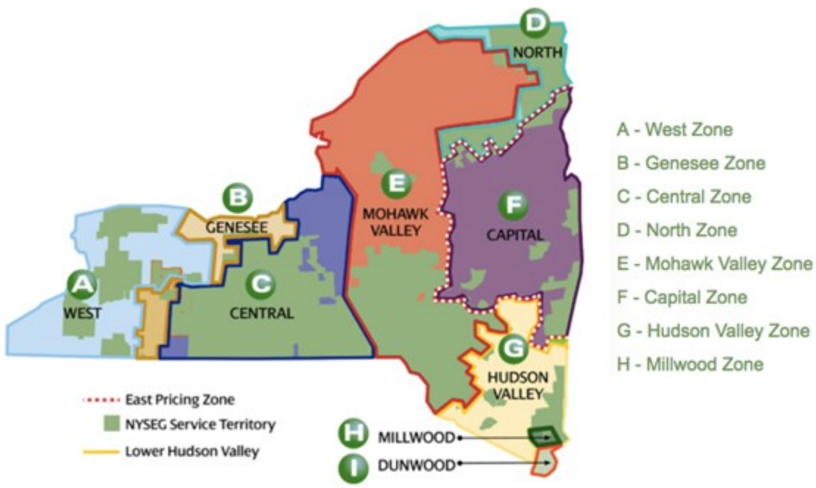
MC Approves CRIS Tariff Revisions

RENSSELAER, N.Y. — NYISO's Management Committee on Wednesday approved Tariff revisions intended to provide external resources with Rest of State (ROS) deliverability rights to improve their ability to participate in the ISO's capacity market.

The March 28 vote recommended that the ISO's Board of Directors authorize staff to file the revisions with FERC under Federal Power Act Section 205.

Ethan Avallone, NYISO senior market design specialist, said Hydro-Quebec US (HQUS) proposed the ISO develop a method for awarding capacity resource interconnection service (CRIS) to entities that create increased transfer capability through transmission upgrades over external interfaces. (See "External Deliverability Rights," *NYISO Business Issues Committee Briefs: March 15, 2018*.)

FERC last year granted HQUS eligibility to receive CRIS in proportion to the incremental transfer capability created by its Cedars Rapids Transmission intertie project (ER17-505). National Grid also stands to benefit from the change after it completes upgrades on its 115-kV Dennison-Alcoa line in Zone D in Q4 2019.



| *New York State Electric and Gas*

2017 CARIS Report Moves to Board

The committee also approved the 2017 Congestion Assessment and Resource Integration Study (CARIS) Phase 1 draft report on the potential costs and benefits of relieving congestion on the transmission system through generic transmission, generation, demand response and energy-efficiency solutions. (See "2017 Congestion Assessment and Resource Integration Study," *NYISO Business Issues Committee Briefs: March 15, 2018*.)

Tim Duffy, economic planning manager, said NYISO has identified three main areas of the state where transmission congestion is: Edic-Marcy, Central East and New Scotland-Pleasant Valley.

To provide additional value to stakeholders, Duffy said the ISO developed a system resource shift case, which assumed retirement of the Indian Point nuclear plant by 2020/2021 and all coal units in the state by 2020, and a resource mix consistent with attaining Clean Energy Standard targets by 2026.

— Michael Kuser

PJM News

PJM TOs, Customers Reposition After Supplementals Order

By Rory D. Sweeney

PJM's Transmission Replacement Processes Senior Task Force (TRPSTF) met on March 28. | *© RTO Insider*

VALLEY FORGE, Pa. — After nearly two years of intractability, FERC's order last month on supplemental transmission projects — and PJM's subsequent compliance filing — have reshuffled the deck in the RTO's Transmission Replacement Process Senior Task Force (TRPSTF).

The order and filing require transmission owners to change how they plan and represent supplemental projects but also give them greater control over defining that process. They forced stakeholders at last week's TRPSTF meeting — the first since submitting the compliance filing — to reconsider how they approach topics that have remained largely unchanged since the task force was proposed in January 2016.

PJM's Steve Herling reviewed the process changes proposed in the filing, which delineate a structure for stakeholder engagement on supplementals and define deadlines for input. Developed internally by TOs through their "local" transmission plans, supplementals are not driven by PJM criteria. They're included with baseline and market efficiency projects in PJM's Regional Transmission Expansion Plan to allow staff to identify possible reliability or operational performance issues, but they are not subject to staff oversight or approval. All stakeholders are supposed to have opportunities to provide "meaningful" input on them, and FERC's order determined that TO procedures weren't allowing that. (See *Group Contests 'Supplementals' Ruling as PJM, TOs Advance*.)

Is Anything Ever Final?

Herling said projects tend to be submitted in "bunches" near the beginning and end of the year.

"I don't know that PJM would be able to second-guess the timing of those decisions," he said when asked to explain the reason for the bunches. He said the focus is to "get the solutions accepted, lock them down and move on so we don't have surprises in the RTEP process."

The deadlines in the compliance filing drew criticism from American Municipal Power's Ed Tatum, who said they might not provide enough time to fully vet projects and receive answers. He asked when local plans are finalized so that stakeholders can comment on them in their entirety.

"The only way I can answer that is to refer to the RTEP. The RTEP is never finalized," Herling said. "I don't know what it means for the RTEP to be finalized, so I would suggest that I also don't know what it means for the local plan to be finalized. … I don't have a problem with putting a flag in the ground and saying, 'We're done.' … I don't know what the significance is from a planning perspective because every year we finish an RTEP, we start another one."

Mark Ringhausen with Old Dominion Electric Cooperative said it seems like "there really isn't a local plan; there's just approval of supplemental projects."

Resolving the Task Force's Work

The TRPSTF went on a 10-month hiatus in response to FERC's show-cause order on the issue, and TOs remained reticent to engage even after the task force resumed meeting late last year at the urging of load-side interests, citing the lack of FERC direction. The order and compliance filing clear the way for resolving the task force's assignments, but how that's accomplished remains to be seen. PJM is hoping the details contained in the order and filing can be accepted by everyone and set aside from debate on the remaining components, but AMP isn't convinced.

"All we're suggesting is we leave the parts that were filed on the table assuming they'll be approved," Herling said.

Tatum suggested having stakeholders propose solution packages and voting on them at an upcoming meeting as is common in other task forces.

"We have been doing nothing for 16 months. … We're still getting ready to try to see if anyone is willing to have a discussion with us," he said. "We've got to finish this group. We've got to stop meeting like this."

Exelon's Gary Guy questioned an all-inclusive approach.

"We're not debating the pros and cons of a commission-issued order," he said. "Once the commission has issued an order, we don't have anything to debate."

While the order undoubtedly has an impact on the task force, the question remains how much. The order is specific to TOs' implementation of Order 890 regarding supplementals, but the TRPSTF is charged with addressing the processes for determining and replacing infrastructure that has reached the end of its usable life. The task force's problem statement, issue charge and charter make no mention of Order 890. PJM's Fran Barrett, the TRPSTF administrator, said he will research any potential

Continued on page 21

PJM NEWS

NJ-NYC Merchant Line OK'd for 'Anchor Customers'

By Rory D. Sweeney

FERC last week granted approval for Linden VFT to contract potentially all of its transmission capacity through long-term "anchor customers" rather than its current recurring auction process (ER18-730).

Linden owns a merchant transmission line and three 105-MW variable-frequency transformers between the Public Service Electric and Gas system in New Jersey and Consolidated Edison on Staten Island, which began operation under PJM's control in 2009. The company has rights to 330 MW of firm point-to-point transmission service from within PJM, 315 MW of export capability from NYISO and 315 MW of delivery into either PJM or NYISO.

Linden has held five "open season" auctions, through which it receives all of its revenue, since 2007. It told FERC there has been a "declining number and diversity of participants and qualified bidders, resulting in shorter-term contracts" and signaling reduced interest in its transmission scheduling rights.

One of Linden VFT's variable-frequency transformers in Linden, N.J. | *Joseph Jingoli & Son*

PSEG Energy Resources & Trade will hold all those scheduling rights as of June, but Linden told the commission it has been approached by new customers seeking "longer-term, more tailored arrangements" and that "the ability to subscribe up to all of [its] transmission capability through such longer-term arrangements with anchor customers will allow it to explore more sustainable, alternative business models and allocate its transmission scheduling rights to the market participants who value them the most."

FERC approved Linden's request to amend its existing authorization so it can contract for service and negotiate rates, payment arrangements and agreement lengths and sell any remaining capacity at market-based rates through open solicitations. The company committed to filing a report within 30 days of a solicitation detailing its open-access characteristics, which allowed the proposal to pass the commission's four-part analysis. Because it had changed its policies on reviewing negotiated-rate proposals since Linden's project was originally approved, FERC decided to conduct a *de novo* analysis.

In December, Linden and Hudson Transmission Partners — another owner of merchant transmission between northern New Jersey and New York City — were approved to convert their lines from firm to non-firm service and avoid being saddled with hundreds of millions of dollars in cost allocations under PJM's Regional Transmission Expansion Plan. (See *NJ Merchant Tx Operators Win Relief on Upgrade Costs*.)

PJM TOs, Customers Reposition After Supplementals Order

Continued from page 20

overlap.

Stakeholders have proposed components that they believe are necessary for any solution, and Barrett asked if PJM staff could analyze them to pull out the parts that have been addressed by the order and filing.

"Could we clean up the past without throwing it away?" he asked.

TOs didn't object to the plan, which would have PJM present an interpretation of what is explicitly addressed by the FERC order, but PPL's Frank "Chip" Richardson pointed out that TOs remain in litigation on some of the TRPSTF's topics and are unable to negotiate on them. Tatum and AMP's Lisa McAlister said they want to maintain the right to go through their proposal and make their own modification interpretations.

They didn't see any benefit to PJM's interpretation.

"We're pretty good with what's in the order and the compliance filing," McAlister said. "I'm not sure it's that helpful."

Guy said he would object to any proposed alternatives to what's in the commission order and said PJM should rule them out of the bounds of the discussion.

"That would be running amok here in complete disregard of what just took place at the commission," he said.

"Discussion is one thing," said Ruth Ann Price, who represents the Delaware Division of the Public Advocate. "Implementation is another. … I'm not sure you have any ability to stop us, the rest of the stakeholder body, going forward."

"Just because we put it out there, doesn't mean there's an affirmation on this," Barrett explained.

He attempted to point to improvements that have been made to the process since the task force began, but Tatum wasn't convinced.

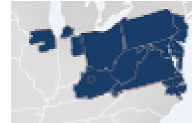
"We are not encouraged by the changes that have been made. We see some progress, but we also see a lot of pullback," he said. "There are certain things that PJM doesn't think about regarding end-of-life projects … so we're going to seek to have those things addressed, as we already have. … There's a lot of things we need to work on. We're very serious about it."

Barrett said subregional RTEP meetings have evolved in response to the task force's work.

"They're not the same calls they used to be," he said.

The TRPSTF's next meeting is scheduled for April 30. Tatum said he hoped that proposed solution packages could be finalized and ready to be voted on by then.

PJM NEWS



FERC Rejects PJM Regulation Plan, Calls Tech Conference

By Rory D. Sweeney

FERC last week moved to investigate PJM's regulation market, rejecting the RTO's most recent proposal for compensating the systemwide service (ER18-87) and ordering a technical conference on larger concerns identified by stakeholders (EL17-64).

The commission denied PJM's most recent proposal, filed in October, for the same reasons it had on previous attempts, which date back to the RTO's efforts to comply with Order 755. The technical conference comes in response to complaints filed in that docket by the Energy Storage Association, Renewable Energy Systems Americas (RESA) and Invenergy Storage Development. They argue that operational changes PJM has made in relation to its filing have had significant negative impacts on battery storage and are "a symptom of the broader problem that PJM misuses regulation resources to reduce generation on its system for sustained periods of time."

FERC granted a portion of the complaints but deferred any action until after the conference and set a refund effective date of April 14, 2017.

Regulation Issues

PJM maintains two regulation signals: RegA dispatches slower, sustained-output resources such as steam and combustion resources, while RegD dispatches faster, dynamic resources, such as battery storage. The RTO uses a "benefits factor" curve to reflect the operational relationship between the signals and establish the tradeoff between their capabilities so that the market's clearing engine can accurately compare their expected performance.

In its original filing on Order 755, PJM had proposed using the benefits factor instead of a unit's actual "mileage" — the amount of regulation work a unit provides — in determining its payment, but FERC rejected that in November 2012 because the order required accounting for a unit's mileage. PJM's January 2013 compliance filing eliminated use of the benefits factor but warned it would create an "unsustainable market structure."

Proposed Regulation Requirements
On Ramp: 800 MW / Off Ramp: 525 MW

Season	Morning On Ramp (hours ending)	Evening On Ramp (hours ending)
Fall: September 1 – November 30	6:00–8:00	18:00-24:00
Winter: December 1 – February 29	5:00-9:00	17:00-24:00
Spring: March 1 – May 31	6:00–8:00	18:00-24:00
Summer: June 1 – August 31	6:00–14:00	19:00-24:00

PJM's updated regulation rules changed requirements from on- and off-peak to on- and off-ramp. | *PJM*

PJM returned to the issue, arguing that its prediction came true and FERC's requirements resulted in over-procurement of RegD and incorrectly signaled for additional entry into the market, which exacerbated the problem. The requirement to unconditionally respect RegD resources' power balance also worked against overall system balance at times, the RTO said.

The RTO redesigned its regulation signals to work together to manage area control error (ACE) and revised the RegD signal to be neutral over 30 minutes rather than 15, it told the commission. It filed for approval of a four-part plan that would substitute the mileage ratio for a new "regulation rate of technical substitution curve" and adjust calculations for performance scoring, settlements and lost opportunity costs. (See *PJM Regulation Compensation Changes Cleared over Opposition*.)

Signal Type	Year	Average of Median Daily ACE
New Signal	2017 (1/9 – 1/31)	34
Old Signal	2017 (1/1 – 1/9)	68
	2016	56
	2015	52

PJM's new regulation signal has helped improve its area control error (ACE) control. | *PJM*

Decision

Stakeholders were mixed in their comments to FERC, with several noting the plan was vetted through the stakeholder process and others calling it discriminatory. The commission disagreed with PJM's contention that the proposal meets its requirements because the market clearing process accounts for the "dollar per mile" cost of RegD resources. It also rejected PJM's argument that accounting for mileage in the settlement equation double-counts it.

In its December order to RTOs on fast-start resources, FERC noted PJM's dispatch process doesn't respect the "power balance constraint" and thus "unnecessarily increases the cost of serving load and puts stress on the frequency regulation resources that are necessary for maintaining system reliability." (See *FERC Drops Fast-Start NOPR; Orders PJM, SPP, NYISO Changes*.)

PJM NEWS

PJM, MISO Considering 2018 Interregional Analysis

By Rory D. Sweeney

MISO and PJM will decide by May 18 whether to undertake a coordinated system plan study this year, the RTOs said last week.

The decision could be announced at the next Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting on May 11. Staff from both RTOs confirmed the timeline at last week's IPSAC meeting, which included the issues review required as part of the process of determining whether a study is required.

"We don't anticipate taking that long," PJM's Alex Worcester explained, referring to the May 18 deadline. He later added that PJM is "likely supportive" of a study.

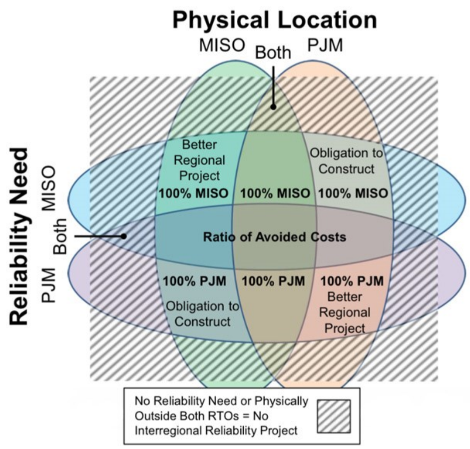
The RTOs will provide justification for their decision, MISO's Adam Solomon said. It will be based on whether there are projects that "make sense," addressing reliability issues on either side of the border that are close to each other.

PJM and MISO in January jointly reviewed their separate regional issues, newly approved projects near their border, coordinated interconnection requests and historical market-to-market congestion, which RTO representatives said would form the basis of the study, if it's undertaken. The results were presented at last week's meeting, along with analysis of stakeholder feedback.

RTOs' Review

Worcester reviewed projects approved through PJM's monthly Transmission Expansion Advisory Committee analysis, including 27 baseline reliability projects near the RTOs' shared border, six market efficiency projects and another six supplemental projects.

All reliability issues identified for 2022 are being addressed through a single proposal window open last summer. Market efficiency projects are addressed on a 24-month cycle that last identified issues in October 2016, but an addendum window to address thermal constraints on the Tanners Creek-Dearborn 345-kV line was closed in



An analysis of site location compared to benefits of interregional projects between MISO and PJM shows that there are nine potential cost allocation categories into which a project could fit. | *MISO, PJM*

February. Supplemental projects are developed internally by transmission owners and are not driven by RTO criteria. They're included with baseline and market efficiency projects in PJM's Regional Transmission Expansion Plan to allow staff to identify possible reliability or operational performance issues, but they are not subject to staff oversight or approval.

Solomon reviewed the 2018 MISO Transmission Expansion Plan, which began in June 2017 and is scheduled to culminate in December 2018 with approval from the Board of Directors for recommended projects. He highlighted 52 approved projects near the RTO border that might spur interregional projects if there are needs nearby in PJM's territory. They are all TO-submitted "bottom-up" projects.

MISO is also reviewing 15 of its most congested north/central flowgates, which will be included in its Market Congestion Planning Study this year to potentially identify market efficiency projects, he said. Nearby PJM economic issues could drive the need for an interregional project. He also noted 21 congestion flowgates that were eligible for the MCPS but were excluded for individual reasons.

Stakeholder Issues

The RTOs also reviewed issues identified by stakeholders. Ameren submitted four issues, while three issues Northern Indiana Public Service Co. highlighted were included in Solomon's presentation.

"We will look at those as appropriate and as they show up in the interregional process," Worcester said.

NIPSCO's final concern involved PJM's finding of 10 facilities with infeasible auction revenue right paths. ARRs are rights to the revenue from congestion charges allocated to firm network and point-to-point customers because they fund the embedded costs of the transmission system. MISO and PJM are each addressing one of the infeasible ties with approved internal projects. Three others have projects under consideration, and two others will be included in a future proposal window. The three remaining infeasible paths are pseudo-tie flowgates. (See "ARR Analysis IDs Constraints," *PJM Planning and Transmission Expansion Advisory Committee Briefs: Nov. 9, 2017*.)

Worcester said MISO has no process comparable to PJM's ARRs, so "if it's outside of PJM, it's unclear how it would move through the [RTOs' joint operating agreement] with the competitive transmission process," he said. PJM will investigate internally ways to address the issues and engage with MISO on any potential solutions, he said.

Wind on the Wires and EDF Renewable Energy asked that the RTOs re-evaluate previously considered targeted market efficiency projects (TMEPs) that did not qualify last year if congestion has continued.

"We certainly agree with that in principle," Worcester said. He said the RTOs aren't planning on reconsidering the Thayer-Morrison project, which Wind of the Wires had specifically requested.

JOA Changes

Seven stakeholders provided feedback on three potential JOA changes, which informed the RTOs' decision-making on the issues. References to joint economic models will be removed.

Continued on page 24

PJM News

PJM, MISO Considering 2018 Interregional Analysis

Continued from page 23

"NIPSCO prefers a joint model," the company's Clark Gloyeske said, noting past differences between the regional models in wind-unit profiles. "More coordination between the regional models to fix some of these modeling issues would be really helpful."

The RTOs have decided against changing the number of benefit years, fixed charges and discount rates used in analyses, Solomon said. While changes were recommended, they were "wildly varying" on what the correct number of years should be.

"Considering all the feedback, the RTOs think this should be a regional discussion," he said. "We think the regional processes are working … and that we shouldn't be deviating from the regional criteria."

"I understand the simplicity of working just within the regions … but if the number of years the benefits are calculated over are significantly different … I think there's a risk of coming up against significant stakeholder or state concern about another region not paying its fair share because they haven't calculated the same level of benefits over the same years," said Natalie McIntire of Wind on the Wires.

Solomon acknowledged the "valid concern" but said it had to be weighed against "regional differences."

"Each region has its own definition of how benefits should be calculated, and that's in line with what we do with our regional projects," he said. "Deviating from that for an interregional project would be difficult, but certainly, your point is taken."

The generation-to-load distribution factor test will be removed, Solomon said, and the RTOs will rely on their own regional materiality tests. This removes a "triple-hurdle concern" that would require projects to pass tests for each region as well as an interregional review, Worcester explained. PJM will develop its test through its recently formed Market Efficiency Process Enhancement Task Force, while MISO is still considering where it will address the question.

"The Tariff is silent on how projects qualify materiality-wise," Solomon said.

Ameren's Adam Weber asked that the regions' materiality tests be delineated in the JOA so stakeholders aren't surprised by a project not clearing both tests. RTO staff hesitated to endorse that proposal but were aligned on addressing Weber's concern.

The grid operators will replace the distribution factor (DFAX) cost allocation method with an approach that allocates costs to the RTO with the reliability need, with split projects allocated based on the ratio of avoided costs. Cross-border baseline reliability projects will be replaced with interregional reliability projects because no scenario exists where the baseline projects would be used. An RTO will be obligated to construct projects that benefit the other RTO, but the benefiting RTO will cover the costs.

"There's not going to be a scenario where there's a new project developed and we would need to come up with a new cost allocation methodology," Solomon said.

The RTOs said they "don't see a need for" EDF's request to add benefit metrics for projects, but a second request to broaden the JOA's definition of a flowgate will be forwarded to the Congestion Management Process Working Group, which has representatives from most RTOs.

The RTOs hope to have the JOA changes in place for the next interregional market efficiency project window, which opens around Nov. 1.

"We're thinking that a filing should be made by July to allow for the FERC process to go through," Solomon said.

SPP NEWS

FERC Approves Service Reductions for SWPA Customers

By Tom Kleckner

FERC last week approved SPP's proposed Tariff revisions reducing network service charges for customers in Southwestern Power Administration's (SWPA) pricing zone, effective April 1 (ER18-769).

The commission agreed with SPP that the proposed revisions, filed in January, will ensure SWPA customers are not charged twice for the same deliveries. FERC noted it had previously accepted similar mechanisms to eliminate double charging for deliveries of statutory hydropower obligations to federal preference customers.

SWPA is one of several Department of Energy power marketing administrations selling hydroelectric power produced at Army Corps of Engineers dams "with preference to public bodies such as rural electric cooperatives and municipal utilities." The agency participates in SPP as a limited transmission owner under the RTO's Tariff, selling excess transmission capacity on its system as non-federal transmission service under grandfathered agreements with individual customers or through its Tariff.

SPP uses SWPA's transmission facilities, located in pricing Zone 10, to provide transmission service, scheduling services, operating reserve sharing, reliability coordination and other services. Attachment AD of the RTO's Tariff "contemplates" the migration of all non-federal transmission service customers to network service or point-to-point transmission service, FERC said.

SPP explained to the commission that network service customers in SWPA's pricing zone are assessed monthly demand charges on a coincidental peak basis under Schedule 9 of the Tariff, based on the customer's total metered load. Because SWPA charges a bundled rate for deliveries of its federal power, federal preference customers could pay twice if they take SPP network service in the zone and do not use any other TOs' intervening facilities, the RTO said.

SPP said the revisions would eliminate the double charging by reducing the eligible network customers' network load by the amount of federal power they receive from SWPA, scheduled at the time of the coincident peak used in calculating Schedule 9 demand charges.

The commission noted SWPA recognized the double charging issue and sponsored the Tariff revision through SPP's stakeholder process. The SPP Board of Directors approved the change in July 2017.

SPP News

SPP's Frequently Constrained Area List Pared to One Area

By Tom Kleckner

FERC on Thursday accepted the recommendations of SPP's Market Monitoring Unit to eliminate the Woodward frequently constrained area (FCA) in Northwest Oklahoma and replace the Texas Panhandle FCA with a smaller one for the Lubbock area. The changes were effective April 1 (ER18-736).

FCAs are areas with high levels of congestion that are also subject to one or more pivotal suppliers.

The Monitor's December 2017 FCA report recommended removing the two historically congested areas that appeared on the 2016 report, while designating one new FCA. The MMU annually reviews and designates SPP's congested areas.

The MMU recommended removing the Woodward FCA — added in January 2016 because of the growth in wind resources in western SPP — because of a decrease in congestion following the Woodward phase shifting transformer upgrade in May 2017.

It said the Texas Panhandle FCA should be removed because it no longer met the threshold of binding for at least 500 hours with a $25/MWh impact during a given 12-month period.

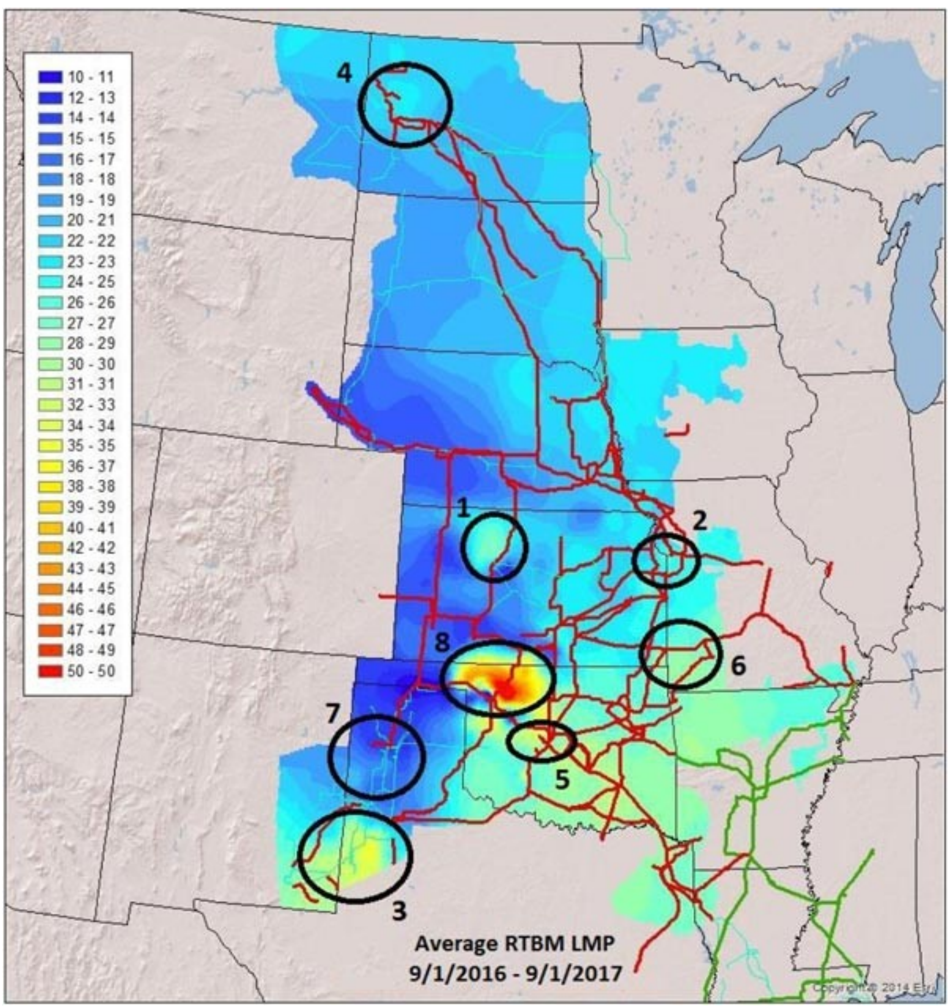
However, the Monitor suggested the Lubbock, Texas, area be added as SPP's lone FCA for this year. The area first appeared as an FCA candidate in the 2015 study and has seen increased congestion since, indicating a shift in congestion south of the Texas Panhandle, the MMU said.

Congestion in this area was part of the southern section of the Texas Panhandle FCA but upgrades north of the Lubbock area and the Woodward-Border-Tuco 345-kV line shifted the congestion to the southwestern edge of SPP grid.

"The Texas Panhandle still sees congestion, but the addition of the Lubbock area better represents where the concern of exercise of market power exists," the MMU said. The Lubbock area saw 686 hours of congestion in 2017.

FERC ruled that the Monitor's suggestion that it simply post the FCA list on SPP's website without the Board of Directors' approval was outside the proceeding's scope. The MMU said that following the Tariff requirement for board approval can take six months, a lag that can lead to outdated FCA lists and that "does not allow SPP or the Market Monitor to efficiently and appropriately address market power concerns."

The commission urged the RTO and its stakeholders to consider the MMU's suggested improvements to the FCA re-evaluation and designation process through the stakeholder process.



SPP's FCA candidate areas | *SPP*

Map Reference #	Geographical Area	FCA Candidate Name
1	Hays, KS	Hays KS
2	Kansas City, KS/MO	Kansas City
3	Lubbock, TX	Lubbock
4	Northern North Dakota	Northern NC
5	Oklahoma city, OK	OK city
6	Southeast Kansas - Southwest Missouri	SE KS – SW MO
7	Texas Panhandle	Texas Panhandle
8	Woodward, OK	Woodward

FCA candidate designations | *SPP*

Company Briefs

Energy Future Holdings' Bankruptcy Fees Top $600M

The law firms, banks and consultants working on Energy Future Holdings' bankruptcy case have received more than $600 million so far, making the case one of the most expensive corporate bankruptcies in U.S. history, according to new data research by The Texas Lawbook.

"The total fees for all the professionals — for the lawyers, bankers, accountants, restructuring experts for all the companies involved — will probably hit $1 billion," EFH General Counsel Andy Wright told the Lawbook in an exclusive interview.

EFH owned 80% of Texas utility Oncor but sold that to Sempra Energy for $18.8 billion on March 9.

More: Houston Chronicle

Dominion Threatens to Withdraw SCANA Offer

Dominion Energy said March 28 it would withdraw its offer to buy SCANA — canceling a plan to offer customers of SCANA's South Carolina Electric and Gas subsidiary $1,000 refunds — if South Carolina lawmakers decide to cut SCE&G's rates.

Dominion's statement came a day after the South Carolina Senate released a study that said it could cut SCE&G's rates by at least 13% without forcing the utility into bankruptcy. The Senate on the night of March 28 tentatively agreed to temporarily lower SCE&G's rates by 13%, but the proposal didn't receive a final vote.

About 18% of SCE&G's rates go to cover the cost of SCANA's share of its and Santee Cooper's failed attempt to expand the V.C. Summer nuclear power plant.

More: The State

OG&E Customers to See Lower Bills from Fuel Cost Reduction

Oklahoma Gas & Electric said March 28 it expects its average residential customer will see their monthly bill drop by $13.34 next month because of an adjustment in the bill's fuel cost portion.

The fuel cost reduction, which is the largest cut in the cost of power that OG&E has made recently, is the result of low natural gas prices and reduced congestion costs stemming from transmission upgrades in northwest Oklahoma.

More: The Oklahoman

Hydro One, Avista File Merger Settlement in Wash.

Hydro One and Avista said March 27 they have filed an "all-parties, all-issues settlement agreement" with the Washington Utilities and Transportation Commission in Hydro One's $5.3 billion acquisition of Avista.

The companies said the settlement includes $44 million in financial commitments to Washington state and that, if those commitments were proportionally allocated to the other states that must approve the acquisition, their total financial commitments would be $74 million.

The commitments in the settlement include $3 million to help Colstrip, Mont., when a coal-fired power plant there that Avista owns part of closes. Avista also agreed to be financially ready by 2027 to close the plant's newest units. Avista has not agreed on a shutdown date for the entire plant, which could operate until the mid-2030s.

More: Hydro One and Avista; Billings Gazette

Santee Cooper Lobbyists Worked to Deter Utility's Sale

Emails and other communications released by South Carolina Gov. Henry McMaster on March 27 show that lobbyists for Santee Cooper worked to derail potential purchases of the state-run utility after promising McMaster they would not oppose its sale.

The lobbyists asked state legislators to openly oppose a sale and pushed the utility's leaders to sweeten deals for its customers so that legislators would feel more comfortable not accepting offers like one from NextEra Energy.

South Carolina is considering selling the state-owned utility in the wake of its involvement with the failed attempt to add two new reactors to the V.C. Summer nuclear power plant.

More: The Post and Courier

Federal Briefs

Audit Finds TVA's Aircraft Purchase Unjustified

The Tennessee Valley Authority's Office of Inspector General on March 29 filed a report saying TVA's purchase of two new fixed-wing aircraft for $17.7 million wasn't justified.

The report stemmed from an audit that sought to learn if TVA's decision to purchase the aircraft was reasonable; how the use of the aircraft compared to the use of aircraft by other utilities and industry standards; and whether the use of the aircraft is consistent with applicable federal laws and regulations.

The report found the TVA's justifications to purchase the aircraft were not supported by analytical cost, safety, reliability or time efficiency documentation, and that the TVA did not comply with federal regulations as well as its policies and procedures regarding use of aircraft.

More: WBIR

NETL: Coal Most Resilient Generation During Cold Snap

The Department of Energy's National Energy Technology Laboratory (NETL) on March 27 released a study it says shows "coal was the most resilient form of power generation" during the cold snap that blanketed much of the East Coast between Dec. 27, 2017, and Jan. 8, 2018.

The report says that during the height of the event on Jan. 5-6, "U.S. electricity market experience demonstrated that without the resilience of coal plants — its ability to add 24-hour baseload capacity — the eastern United States would have suffered severe electricity shortages, likely leading to widespread blackouts."

Continued on page 28

Federal Briefs

Continued from page 27

NETL said the report "indicates that continued retirement of fossil fuel power plants could have an adverse impact on the nation's ability to meet power generation needs during future severe weather events."

More: *National Energy Technology Laboratory*

EPA Looking into Shortening Air Pollution Permit Process

EPA is investigating how to shorten the time needed to get air pollution permits for building or expanding power plants or factories, Chief Operating Officer Henry Darwin said.

The agency wants to determine what is holding up the issuance of permits under the New Source Review program, Darwin said during the Environmental Council of the States conference, which was held in St. Paul, Minn., March 20-22.

EPA Administrator Scott Pruitt's goal is to cut in half by September 2019 the number of permitting decisions that take longer than six months to reach.

More: *Bloomberg BNA*

State Briefs

ARIZONA

Senate Committee Approves Alternate Renewable Referendum

The Senate Appropriations Committee on March 27 voted to place a renewable energy referendum on the November ballot, but critics say its purpose is to confuse voters who otherwise would support a renewable energy measure that a group backed by billionaire Tom Steyer seeks to get on the ballot.

Both measures would require electric companies to get half their power from renewable sources by 2030. The referendum advanced by the committee, however, would make the requirement unenforceable if it becomes too costly.

More: *The Republic*

CALIFORNIA

SFPUC Says PG&E Requirements Delaying City Projects

Barbara Hale, the San Francisco Public Utilities Commission's (SFPUC) assistant general manager in charge of power, said March 27 that at least 16 city projects are being delayed because Pacific Gas and Electric is requiring new construction or renovation projects be built to handle enormous electricity loads that are much more than the projects require.

PG&E is able to impose that requirement because it owns the power lines that transport SFPUC power from the hydroelectric plants that are part of the Hetch Hetchy Project. SFPUC thinks 17 upcoming projects could also be impeded by the requirement.

O'Shaughnessy Dam, part of the Hetch Hetchy Project

PG&E spokeswoman Andrea Menniti declined to answer specific questions but said in an email that "PG&E is committed to collaborating with the city and county of San Francisco to help the SFPUC serve its customers, and we continue to energize electric projects safely and as quickly as possible."

More: *San Francisco Chronicle*

KENTUCKY

LG&E, KU Ask PSC to Reconsider Rate Reduction Order

Louisville Gas & Electric and its sister company, Kentucky Utilities, have asked the Public Service Commission to reconsider its order requiring them to lower their rates by about 6% to reflect the federal Tax Cuts and Jobs Act.

In their request, the utilities cited factual and process errors by the commission in its March 19 order. On March 27 they threatened to go to court if the commission refuses its request for reconsideration.

More: *Louisville Courier Journal*

FERC Rejects Clarification On EKPC QF Order

FERC on March 26 rejected a solar developer's request for clarification of its September 2017 order relieving East Kentucky Power Cooperative of its obligation to purchase power from Public Utility Regulatory Policies Act qualifying facilities larger than 20 MW.

The commission granted EKPC a PURPA exemption based on the cooperative's participation in PJM's wholesale markets, effective June 9, 2017, the date of its application. (See *EKPC Gets PURPA Exemption; Still on Hook for 2 QFs*.) The commission said the ruling would not relieve EKPC of having to purchase from two QF solar farms that had notified the coop, before the its application, of their intent to sell their output to it at an avoided cost rate before the utility's application. BayWa r.e. Solar Projects notified EKPC of plans for its 80-MW Bluebird solar QF on Dec. 5, 2016, and its 60-MW Blue Jay QF on March 8, 2017.

The commission said its ruling did not negate the solar developer's grandfathered QF rights "[b]arring any restrictions under state law." The developer asked FERC to specify that any state law restrictions that violate PURPA or were not in effect at the time East Kentucky filed its application do not affect its grandfathered status. But the commission rejected the request saying, "Granting clarification or rehearing based on petitioners' speculative concerns that the Kentucky [Public Service] Commission may improperly interpret PURPA or impose new restrictions subsequent to the Sep-

Continued on page 29

STATE BRIEFS

Continued from page 28

tember order would require our action prematurely. We do not know what the Kentucky commission may do, and, in fact, it may do nothing that would be inconsistent with petitioners' having established legally enforceable obligations."

More: QM17-5-001

MARYLAND

Utilities Propose Spending $104 Million on EV Network

The state's electric utilities have filed a proposal with the Public Service Commission to spend $104 million deploying 24,000 charging stations to help the state meet its goal of getting 300,000 electric vehicles on state roads by 2025.

The proposal asks the utilities' customers to pay 25 to 42 cents more a month to support the buildout.

The utilities involved in the filing include Baltimore Gas and Electric, Potomac Electric Power, Delmarva Power and Potomac Edison.

More: The Baltimore Sun

MICHIGAN

PSC Cuts Consumers' Desired Rate Increase by 62%

The Public Service Commission on March 29 approved a nearly $66 million rate increase for Consumers Energy, 38% of what the utility originally sought.

Consumers last March 31 asked for a $173 million increase. It subsequently lowered that to $148 million and on Oct. 1, 2017, self-implemented a $130 million rate increase.

Since the self-implemented increase hiked the bills of residential customers using 500 kWh of electricity per month by about $2.46, the commission's ruling will decrease those bills by 59 cents.

More: The Associated Press

Lansing BWL Commissioners Approve New Gas Plant

The Lansing Board of Water and Light on March 27 unanimously approved constructing a natural gas-fired power plant.

The approval will allow Lansing's city utility to issue up to $500 million in bonds to finance the plant's construction, invest in renewable energy and make operational improvements. The utility's general manager said about $450 million will go to building the new plant.

The utility said the plant will complement its renewable energy projects and allow it to close its two coal-fired plants, one in 2020 and one in 2025. The plant will be located on the site of the coal-fired plant that is closing in 2025 and is expected to go online in three years.

More: Michigan Radio

NEW JERSEY

BPU Issues Tax Cut Rate Reduction Orders

The Board of Public Utilities on March 26 issued 16 orders approving rate reductions effective April 1 that pass savings from the Tax Cuts and Jobs Act through to the customers of nine water companies and seven gas and electric companies.

The orders reduced rates by approximately $215 million for power and gas customers of Atlantic City Electric, Elizabethtown Gas, Jersey Central Power and Light, Public Service Electric and Gas, New Jersey Natural Gas and Orange and Rockland Electric.

Utility rates in the state include the tax liabilities of the utility companies. The utilities' tax liabilities were reduced by the act from 35% to 21%.

More: New Jersey Board of Public Utilities

OKLAHOMA

Senate OKs Bill on Wind Farm Development near Military Facilities

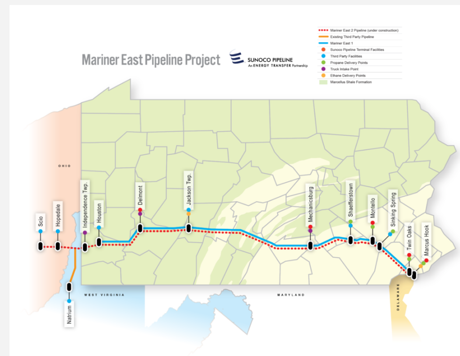
The Senate on March 28 unanimously approved a bill to require developers of wind farms near military facilities to take steps to make sure the wind farms don't interfere with the facilities' operations.

Under the bill, which was approved 91-1 by the House of Representatives, developers of wind farms near military facilities must get an active Determination of No Hazard or an approved mitigation plan from the U.S. Department of Defense Siting Clearinghouse before construction. They also must notify the Military Strategic Planning Commission so it can notify local base commanders.

More: The Oklahoman

PENNSYLVANIA

Court Rules Pipeline's Utility Status Trumps Local Law



| Sunoco

The Commonwealth Court on March 26 ruled that the public utility status of Sunoco Pipeline's Mariner East 2 trumps a Middletown Township ordinance prohibiting pipelines from passing less than 75 feet from a residence.

The ruling was issued in an appeal by six Middletown residents who sought to have the ordinance enforced against Sunoco, which is building the pipeline to carry natural gas liquids such as propane from the Marcellus Shale region to a terminal on the Delaware River in Marcus Hook.

The court said its ruling was consistent with its February rejection of a lawsuit led by the Delaware Riverkeeper Network that sought to enforce a West Goshen ordinance specifying how far a pipeline must be constructed from occupied structures.

More: The Philadelphia Inquirer

RHODE ISLAND

Siting Board Member Agrawal Resigning

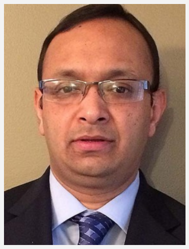
Parag Agrawal is resigning from his post as associate director of the Division of Planning effective April 13, meaning he

Continued on page 30

State Briefs

Continued from page 29

likely won't be on the Energy Facility Siting Board when it decides the fate of a natural gas power plant that Invenergy wants to build in Burrillville.


Agrawal

Agrawal's duties include sitting on the three-member board, which has scheduled the start of its final hearing on the power plant for April 11. A member of a community organization that opposes the power plant said he is concerned about a new person getting involved in the board's deliberations on the power plant after the comment period has ended.

A division of administration spokeswoman said there is neither a plan to immediately replace Agrawal nor a timeline for doing so. The board can approve licenses with just two members.

More: Rhode Island Public Radio

UTAH

Gov. Herbert Signs Two Residential Solar Bills

Gov. Gary Herbert on March 27 signed into law two bills meant to benefit residential solar energy customers.

One bill requires solar companies to provide residential customers with disclosure statements that summarize key terms in the agreements they sign. The disclosure statements were modeled on the standardized disclosure forms that the Solar Energy Industries Association developed for the public.

The other law extends for two years a $1,600 tax credit for homeowners that get residential solar generation systems. It's meant to help the solar industry adjust to recently restructured residential solar rates.

More: Solar Builder

VIRGINIA

Court Makes Switching Providers Easier for Large Consumers

The state Supreme Court on March 29 rejected Dominion Energy's appeal of a decision by the Corporation Commission that large electricity users seeking all-renewable power can switch to an independent power provider without having to give five years' notice if they want to resume getting power from their local utility.

The commission issued its decision in a case brought by Direct Energy Services, which is seeking to sign up residential and commercial utility customers for its 100% renewable energy product.

A Dominion spokesman said the company is reviewing the order.

More: Richmond Times-Dispatch

WYOMING

Utilities Ordered to File Tax Cut's Effect on Rates

The Public Service Commission on March 26 ordered utilities to file by March 30 an initial assessment of the federal Tax Cuts and Jobs Act on their rates and a statement of whether they anticipate adjusting their rates due to the reduction of the corporate tax rate contained in the act.

Utilities that don't think they'll need to adjust their rates to account for the effects of the act, which reduces the federal corporate tax rate to 21% from 35%, should explain why in their filing, the PSC said in the order.

Utilities with rate cases open before the commission should address the effects of the act in those proceedings, according to the order.

More: Wyoming Public Service Commission

Peak/PJM Enter Western Market 'Commitment Phase'

Continued from page 1

Peak said it continues to receive notices from utilities intending to withdraw from its reliability services but is not making public the number that have filed. The organization has noted that market participants are highly likely to receive RC services and market services from the same source.

"I can say we have not received notices from all of our funding parties," Peak spokeswoman Rachel Sherrard told *RTO Insider*. "I would note that, with the exception of one entity, all notices received so far are revocable." The non-revocable notice is from CAISO, which will leave Peak on Sept. 2, according to organization documents.

The Peak/PJM commitment phase will consist of confidential meetings with interested parties "to review more details on the plan's assumptions, market size scenarios, expected transactional cost ranges, projected aggregate efficiency savings and proposed services within the business plan," the organizations said.

They envision the market will initially roll out with a day-ahead and real-time market using LMP and forward transmission rights for hedging. A full RTO would then be developed at the behest of market participants. (See Peak Touts 'Independent' Western Market Plan.) Existing RC services would be offered as well as balancing authority services, transmission operation, real-time grid monitoring and control, and interregional congestion management. A NERC-certified RC is needed to comply with the reliability organization's standards.

Peak has highlighted its knowledge of the Western grid as an RC, while PJM brings its experience in market design and operation. (See PJM Chief Confident on Western Market Proposal.) The real-time market would include spot energy, synchronous and nonsynchronous reserves, and frequency regulation. The day-ahead offering would include a virtual energy market, while the FTR offering would allow a forward hedge price differential between nodal and aggregate locational pairs.

Peak says its funding level will remain flat through 2019. It has scheduled an April 11 conference call on its market initiative.

CAISO says it will "shadow" Peak RC services and then launch its own RC offering by spring of 2019.

Is RTO Tx Planning Hampering Green Corporate Goals?

Continued from page 1

affairs and sustainability, said last week.

"If we're going to actually get [renewables] … actually running our facilities, instead of just being out there buying the [renewable energy credits], we've got to really focus on transmission."

Even as President Trump has moved to undo the Obama administration's climate initiatives, large corporate energy buyers such as Unilever have accelerated their commitments to purchase carbon-free electricity. But their efforts may be frustrated because of insufficient transmission to move Midwest wind power to load centers, according to a study released by the Wind Energy Foundation. The study was the subject of a webinar last week by Americans for a Clean Energy Grid (ACEG), a coalition whose members include the Natural Resources Defense Council, WIRES, ITC Holdings and American Electric Power.

Transmission Project Name (State)	Voltage (kilovolts, kV)	Estimated In-service Date	Estimated Potential Wind Capacity (MW)
MISO Multi-Value Projects (ND, SD, IA, MN, WI, IL, MO, MI)	345, one 765 line	2015-2020	14,000
Grand Prairie Gateway (IL)	345	2017	1,000
Southline Transmission Project (NM, AZ)	345, 230	2018-2020	1,000
Power for the Plains (NM, TX, OK)	115, 230, 345	2016-2020	1,230
Pawnee—Daniels Park (CO)	345	2019	600
Gateway West (WY, ID)	500	2019-2021	3,000
Empire State Connector (NY)	320 DC	2020	1,000
Transwest Express (WY)	600 DC	2020	3,000
Sunzia (NM, AZ)	500	2020	3,000
Clean Line Projects (KS, OK, IA, NM, AZ)	600 DC	2020+	16,000
Southern Cross (TX)	500 DC	2021	2,000
SPP 2012 ITP10 Projects (TX, OK, KS, MO)	345	2018-2022	3,500
Gateway South (WY, UT)	500	2020-2024	1,500
Boardman-Hemingway (OR, ID)	500	2022	1,000
Total Potential New Transmission Capacity			**~52 GW**

Transmission line activity serving renewable energy projects | *David Gardiner and Associates, for the Wind Energy Foundation*

15 States Hold Most Onshore Wind

The study concluded that transmission expansions currently planned will likely be insufficient to support large corporate energy buyers' renewable energy goals because most of the solar and wind power potential is in 15 Midwestern states, far from load centers. The 15 states hold 88% of the country's wind technical potential and 56% of its utility-scale solar photovoltaic potential, but they are home to only 30% of projected 2050 electricity demand.

This is based on the Renewable Energy Buyers Alliance (REBA) goal of obtaining 60 GW of new renewables by 2025 and the 52 GW of new transmission capacity planned in 14 near-term projects in advanced development in MISO, SPP, PJM and NYISO (see table).

In three of the four scenarios studied, transmission would be insufficient to meet corporate renewable demand. With 9 GW of renewables procured by corporate purchasers since 2013, about 51 GW remain to meet the goal. If RTOs build 90% of the capacity in the 14 projects, only 70% of the corporate demand would be filled, the study said. If corporate procurements fall short at only 20 GW, the transmission projects would meet the corporate needs, the study said.

According to the study, one of the biggest obstacles to bringing more renewable energy online is "the absence of transmission planning across RTOs and other regional planning authorities."

Not Counting All the Benefits

"I think that current [transmission] planning process doesn't do an adequate job of really counting up all of the benefits, and then it doesn't think about it … in a … broader geographic scale," said David Gardiner, president of David Gardiner and Associates, which conducted the study for the foundation.

"We've built the interstate highway system in this country not because the highway system went from point A to point B, and the people along point A and point B paid for it, but because we recognized that it provides national benefits, and therefore everybody contributed nationally. We need to be thinking about how we assess the benefits and think about how we want to pay for things more along those lines than we currently are."

The study recommends that corporate and institutional energy buyers participate in regional and interregional transmission planning and urges FERC and RTOs to improve interregional planning under Order 1000. It said RTOs should incorporate voluntary, large customer demand in transmission planning.

"While we highlight a few examples in the report of companies like Stefani's that have engaged in some of the planning for transmission lines, it's been limited, and we're going to need to step up the kinds of engagement in the transmission planning process as we go forward," Gardiner said.

Gardiner's study found that while transmission planners "in rare instances" account for voluntary goals, such as statements by governors, they do not account for growing voluntary demand from large corporate purchasers. "Instead, RTOs typically only focus on mandatory renewable energy requirements prescribed by [renewable portfolio standards].

"If a governor issues a voluntary goal to develop 1 GW of renewable energy in the state, some RTOs would typically include assumptions to meet that 1-GW target in transmission planning models. Although the goal may not be a mandate … other RTOs do only what FERC requires, which is to 'consider' public policy and may ultimately opt not to include state RPSs or other policies in their plans."

RTOs Respond

Officials of MISO, PJM and SPP told *RTO Insider* last week they are adding transmission for renewables as best they can under FERC transmission planning and cost allocation rules.

"Lack of transmission expansion to facilitate renewable deliveries across regions is not due to inadequate transmission planning between the regions," said SPP Vice President of Engineering Lanny Nickell in a statement. "Rather, the lack of expansion primarily derives from the difficulty in achieving agreement among multiple groups of customers as to who receives the benefits and, thus, who should pay for

Continued on page 32

Is RTO Tx Planning Hampering Green Corporate Goals?

Continued from page 31

transmission upgrades."

Nickell noted that SPP and other RTOs consider varying amounts of renewable transfers between regions in their interregional transmission planning studies. "RTOs have largely addressed this issue within their regions due to FERC-approved cost allocation mechanisms for service contained in their areas. However, customers in other regions are sometimes challenged to deliver renewable energy from regions like SPP's because they are unwilling to bear the costs of required infrastructure upgrades or because it is difficult to find other customers willing to share the costs of those upgrades that they don't believe benefits them," he said.

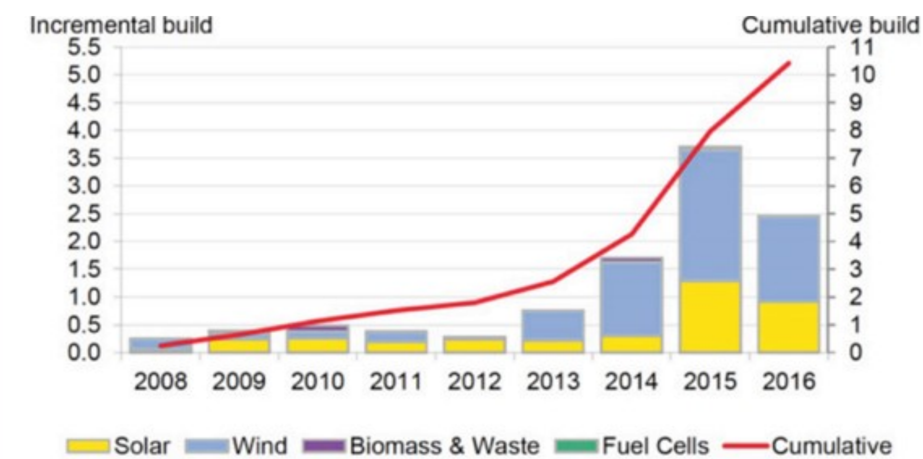
"We believe our transmission planning process does adequately address large customers' increased demand for renewable energy," said Eli Massey, MISO's senior adviser for policy studies, in a statement. "MISO's top-down transmission planning examines regional economics, and its bottom-up planning examines local load growth and reliability issues in order to optimize the transmission system. MISO's transmission planning process already facilitates the study's recommendation that large customers engage in the transmission planning process through the industry sector mechanism of the Planning Advisory Committee."

PJM spokesman Ray Dotter said the RTO accounts for transmission for renewables through its markets and interconnection process.

"We do not plan or build transmission lines on speculation alone," he said "The developers of new generation of any type are required to pay for the transmission upgrades necessary to deliver the output of their projects. The principle has been that consumers should not pay for transmission required because of generation developers."

He noted that PJM's state agreement approach allows states to take responsibility for the costs of transmission expansions addressing their public policy requirements. FERC approved the state agreement approach in a 2015 ruling as part of the RTO's plan to integrate multi-driver projects into the Regional Transmission Expansion Plan (ER14-2864). (See *PJM Wins OK on Multi-Driver Tx Projects*.) PJM said the multi-driver concept could lower the cost of states' public policy transmission projects by incorporating them in upgrades that address market efficiency or reliability.

Nickell said SPP considers voluntary and mandatory renewable goals in its planning assumptions. "If a wholesale customer, under the SPP Tariff, desires to buy from a new or existing renewable resource to supply the needs or goals of its customers and submits a request for transmission service from SPP, we are obligated to plan the system to accommodate the requested service, as long as the customer agrees to fund any requisite upgrades. SPP will consider any and all requests for transmission service made to deliver energy from existing or future renewable resources to prospective buyers and will direct construction of transmission upgrades on the SPP system needed to accommodate those requests in accordance with the respective customers' service agreements."



Renewable capacity contracted by corporations by technology, 2008-2016 (megawatts) | *David Gardiner and Associates, for the Wind Energy Foundation*

RPSs — which currently represent 10% of MISO's load — are considered the base level of renewable penetration in its transmission planning modeling futures. "Large customer demand for renewable energy is included in alternative modeling futures on an additive basis that range up to 30% penetration of MISO system load," Massey said. "We believe that level of penetration fully captures the stated goals of large customers and still leaves room for additional growth."

Massey, who also spoke at the webinar, said it is the scheduling of transmission to deliver power under a PPA that signals load growth to MISO.

The RTO also learns of PPAs from stakeholders. "But because MISO is not a signatory to the power purchase agreement, we don't always know about these power purchase agreements, so it's difficult to plan in that context."

ACEG Executive Director John Jimison, who moderated the webinar, noted that "it only takes a couple of years" to bring a wind farm or central solar plant into operation, shorter than the timeline for developing new transmission. "How do you anticipate the need for transmission so that you don't expect people to put up a wind farm and then wait five years before they can actually transmit the power?" he asked.

Massey said MISO accounts for that disparity through its multi-value projects (MVPs). He cited the wind-rich Buffalo Ridge area of southwest Minnesota, northwest Iowa and eastern South Dakota. "We know that there's a tremendous amount of wind capacity there, and in the current incentives regime with the production tax credit … and because the cost of wind generators is coming down rapidly, we know that there's going to be wind locating there."

MISO has about 37 GW of wind and 21 GW of solar in its interconnection queue. "The good news is that it takes a long time for even those plants to get through the generator interconnection process, and this gives us a little bit of lead time in the transmission planning process to identify projects that we're going to need on a regional basis, that we can predict based on what the wind capacity is and where we know the load is," Massey said.

Continued on page 33

FES Seeks Bankruptcy, DOE Emergency Order

Continued from page 1

Beaver Valley

expected since at least February, when FirstEnergy CEO Charles Jones predicted it in a company earnings call. (See *FirstEnergy CEO Predicts Death of FES, Coal, Nuclear*.)

In a statement, FirstEnergy made clear that the bankruptcy proceedings only applied to FES and its subsidiaries, including First-Energy Nuclear Operating Co. Jones touted the move as part of the company's strategy to get out of the competitive power industry.

"Becoming a fully regulated utility company should give FirstEnergy a stronger balance sheet, solid cash flows and more predictable earnings. Simply put, we will be better positioned to deliver on the tremendous opportunities for customer-focused growth," he said.

According to Bloomberg, FES is about $3.6 billion in debt, of which 60% is in municipal bonds. It had faced an April 2 deadline to pay bond holders $100 million.

'Immediate Action' Requested

In its 44-page letter to Secretary Perry, FES said the premature retirements of its three plants, along with other coal and nuclear plants in PJM, constitute an emergency threat to the reliability of the RTO's grid. It cited as evidence a report released just two days earlier by the Department of Energy's National Energy Technology Laboratory that said coal "provided the most resilient form of generation in PJM" during the January cold snap known as the "bomb cyclone."

"PJM continues to claim that all is well with its system, but at the same time shows it does not have a clear view of what resilience is, how to measure it or how to ensure it," FES told Perry. "PJM has demonstrated little urgency to remedy this problem any time soon — so immediate action by the secretary is needed to alleviate the present emergency."

PJM rejected FES' allegation. "This is not an issue of reliability," PJM said in an emailed statement. "There is no immediate emergency."

FES also criticized FERC for rejecting DOE's Notice of Proposed Rulemaking that would have directed all RTOs and ISOs to compensate the full operating costs of any generating facility with 90 days of onsite fuel. The commission instead opened a new docket to receive input on the resilience issue. (See *RTO Resilience Filings Seek Time, More Gas Coordination*.)

"Despite the fact that the time for such remedial action has come, FERC terminated your rulemaking proceeding and chose instead merely to study the issue further," the company wrote. "FERC's response was disappointing. FERC's reliance on comments by RTOs/ISOs — the very entities that preside over the flawed markets — is misplaced. More fundamentally, FERC's decision to study the issue further is too little, too late."

FERC recently extended the deadline to May 9 for intervenors to submit comments in response to the grid operators' filings (AD18-7).

Continued on page 34

Is RTO Tx Planning Hampering Green Corporate Goals?

Continued from page 32

Order 1000

Although Order 1000 requires RTOs to jointly plan transmission with their neighbors — and to "consider" whether needs identified in local and regional transmission plans could be addressed more cost-effectively through joint projects with a neighboring region — it does not require them to build anything.

Developers say another reason for the dearth of interregional transmission projects is disparities in regions' competitive processes, cost allocation and means of valuing potential expansions. (See *Developers Lament Lack of Tx Competition, Interregional Projects under Order 1000*.)

FERC has attempted to address those concerns. In 2015, for example, it ordered MISO to adopt SPP's cost allocation method for interregional transmission projects addressing reliability needs. (See *FERC Orders MISO to Use SPP Cost Allocation Method in Reliability Projects*.)

The commission will conduct a technical conference beginning today on how RTOs coordinate generator interconnection studies on projects near their seams, saying their practices may not be just and reasonable (EL18-26, AD18-8).

FERC called the conference to address issues raised in EDF Renewable Energy's complaint against PJM, MISO and SPP last year, which contends that inconsistencies and a lack of clarity in the RTOs' rules for "affected systems" interferes with developers' ability to judge the commercial viability of proposed projects. An affected system is one that may be impacted by an interconnection in a neighboring "host" system.

FES Seeks Bankruptcy, DOE Emergency Order

Continued from page 33

FPA Section 202c

FES' requested order, which would be invoked under Section 202c of the Federal Power Act, would apply to "nuclear and coal-fired generators located within the PJM footprint that have a supply of fuel on site sufficient to allow 25 days of operation at full output; that are substantially compliant with all applicable federal, state and local environmental laws and regulations; and that do not recover any of their capital or operating costs through rates regulated by a duly authorized state regulatory authority, municipal government or energy cooperative."

Those plants would "be compensated with just and reasonable rates that provide for full recovery of its fully allocated costs and a fair return on equity."

FES also requested that in cases when PJM and a qualifying plant are unable to reach an agreement on rates, "the secretary step in and determine the just and reasonable compensation and conditions." It also asked that the order remain in effect for at least four years or "until the secretary determines that the emergency has ceased to exist because the PJM markets have been fixed to properly compensate these units for the resiliency and reliability benefits that they provide."

The Energy Department has used its authority to declare emergencies eight times since 1977 — when the Department of Energy Organization Act transferred this power from FERC to the secretary of energy — beginning with the Western Energy Crisis of 2000. Perry has invoked it twice: last April for the Oklahoma-owned Grand River Dam Authority's Grand River Energy Center Unit 1, and in June for Dominion Energy's Yorktown plant. (See *DOE Approves Emergency Dispatch of Yorktown Units*.)

In both cases, the plants were coal-fired. And in both, Perry issued the orders less than five days after receiving the requests from the plants' owners. In Yorktown's case, PJM had also filed a request.

Section 202c limits any emergency action to 90 days if it conflicts with any other law, although it allows the secretary to extend the emergency for another 90 days after a

Perry nuclear plant

review. Perry has renewed the Yorktown request twice, as PJM had requested that it stay in effect until the construction of a needed transmission line in the Historic Triangle region of Virginia.

However, FES said that "because the eligible nuclear and coal-fired generators must continue to substantially comply with all applicable federal, state and local environmental laws and regulations, the provision in Section 202c limiting the duration to a 90-day period is not applicable."

Robert Murray, CEO of coal producer Murray Energy, has been lobbying the Trump administration to issue an emergency order for FirstEnergy's Ohio coal plants, his company's biggest customer, since at least last July. Perry had reportedly rejected the use of such an order in August, opting instead to issue the resilience NOPR. (See *Photos Show Murray's Role in Perry Coal NOPR*.)

Bloomberg, citing anonymous sources, reported in February that DOE officials were still considering the use of 202c for FirstEnergy's coal plants, but the department countered that the sources were "misinformed." Nevertheless, Undersecretary Mark Menezes told Bloomberg that "we have authorities that we can use when the need arises. They're well known. And we'll use them if we need to."

PJM, Stakeholders React

PJM acknowledged fuel supply diversity is important. "But the PJM system has adequate power supplies and healthy reserves in operation today, and resources are more diverse than they have ever been. Nothing we have seen to date indicates that an emergency would result from the generator retirements," the RTO said. "The potential for the retirements has been discussed publicly for some time. In anticipation, PJM took a preliminary look at the effect of the retirements on the system. We found that the system would remain reliable. We have adequate amounts of generation available."

In February, PJM issued a report showing that its grid performed reliably during the cold snap but that price formation changes were needed, echoing comments that CEO Andy Ott made in January before the Senate Energy and Natural Resources Committee. (See *PJM: Cold Snap Uplift Shows Need for Pricing Changes*.)

Condemnation of FES' request was widespread across stakeholder sectors and interests.

"FirstEnergy does not speak for its own customers, as strong opposition from their customers to past FirstEnergy bailout attempts clearly shows, much less their attempt to speak for all 65 million customers who depend on PJM," the Electric Power Supply Association said. "Similarly, FirstEnergy does not speak for all other coal and nuclear asset owners."

On Friday, EPSA joined with 10 other trade associations — the American Council on Renewable Energy, American Forest & Paper Association, American Petroleum Institute, American Wind Energy Association, Electricity Consumers Resource Council, Independent Petroleum Association of America, Interstate Natural Gas Association of America, Natural Gas Supply Association, Solar Energy Industries Association and Advanced Energy Economy — to request that Perry allow comment on FES' filing, citing the company's failure to seek rehearing of FERC's decision on the resilience NOPR.

"It would be manifestly unreasonable and unfair to both other interested parties and the secretary for FE Solutions to demand that the secretary act without hearing from interested parties, including PJM, after having failed to exercise its right to request rehearing before FERC and waited nearly three months before challenging FERC's order through the March 29 request to the secretary," the groups said.

The Sierra Club said a 202c order would be illegal and promised to sue the department if Perry granted FES' request. "If the Trump administration bows to FirstEnergy and moves forward with this bailout attempt, Sierra Club fully intends to challenge and defeat the administration in court," said Mary Anne Hitt, director of the group's Beyond Coal campaign.

Continued on page 35

FES Seeks Bankruptcy, DOE Emergency Order

Continued from page 34

NRG Energy spokesman David Gaier called FES' request "a solution in search of a problem."

"The only crisis here is one affecting FirstEnergy's shareholders, and Ohio ratepayers should not be asked to bail out FE for its inability to profitably operate its power plants," Gaier said.

John Moore, director of the Natural Resources Defense Council's Sustainable FERC Project, said, "FirstEnergy is desperate to pad its bottom line at the expense of its customers. The region is awash in cleaner and cheaper resources, and FirstEnergy can't compete in the market. This move is stunning given that the Federal Energy Regulatory Commission, the Department of Energy and the state of Ohio have all rejected these bailouts."

"PJM has twice the reserve margin it needs so this fuel supply crisis is completely manufactured," said Rob Gramlich, president of Grid Strategies, a renewable energy consultancy. "PJM has been quite accommodating in my opinion, asking FERC for a nationwide ruling and to be directed to make market design changes if they deem necessary. They're punishing some pretty good deeds."

While the Nuclear Energy Institute lamented the plant closures, it did not express direct support for FES' request.

"The announcement from FirstEnergy to retire more than 4,000 MW of nuclear power generation demonstrates the urgency for policymakers to act before it is too late," said John Kotek, NEI vice president of policy development and public affairs. "All options to prevent the closure of nuclear plants should be explored."

Nuke Closures

In Wednesday's announcement of the nuclear plant closures, FES Generation President Don Moul repeated its call for "elected officials in Ohio and Pennsylvania to consider policy solutions that would recognize the importance of these facilities to the employees and local economies in which they operate, and the unique role they play in providing reliable, zero-emission electric power for consumers in both states."

Zero-emission credit legislation similar to that passed in Illinois and New York has stalled in Ohio, however.

The plants have a combined capacity of slightly more than 4 GW, representing about 65% of the electricity FES generated in 2017, according to the company.

"PJM has an established 90-day process to review generator retirement requests. We will conduct the full analysis required to determine if there would be any local effects on the grid," the RTO said in its statement. "However, given the unusually long advance notice, there would be sufficient time to complete any transmission upgrades required."

It also noted there are about 10 GW of generation in Ohio under construction or in the interconnection queue.