RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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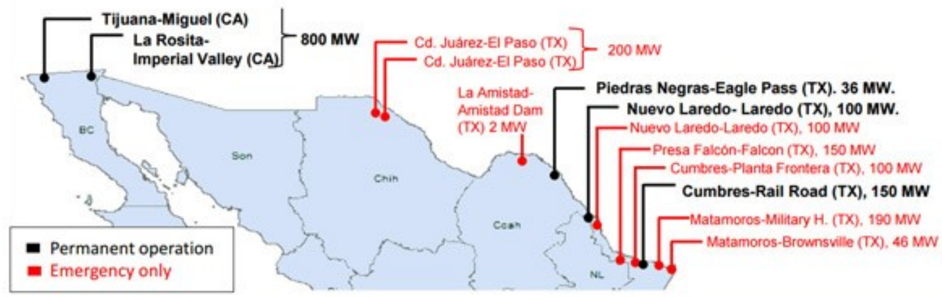
Trump Casts Shadow over Growing Mexican Market

By Tom Kleckner



Cross-border interconnections | *Mexico Ministry of Energy*

AUSTIN, Texas — When Diego Villarreal looks north across the Rio Grande toward Texas, he sees a deregulated energy market that looks very much like his country's.

That stands to reason: Mexico has borrowed the best elements of competitive markets from around the globe and learned from U.S. "success stories" — including ERCOT.

In less than four years, Mexico's electricity sector has been transformed from a state-run monopoly into a burgeoning market-place where energy, capacity, financial transmission rights and clean-energy certificates are traded in day-ahead, real-time and capacity markets.

Villarreal, the deputy managing director of electric industry coordination for Mexico's Ministry of Energy, takes understandable pride in the transformation.

"Where we are right now … that basically took Texas about 10 years," he said during Infocast's ERCOT Market Summit. "We have been working nonstop to get it where it is in only three and a half years. Yes, there are some elements missing, but keep in mind, it's only been three and a half years."

Key to the market's reform, Villarreal told his audience, was the concept that Mexico "is not an isolated island," but part of a regional market where "integration can lead to lower prices and more generation" — all of which could be quickly disrupted if the Trump administration continues to insist on building a large physical wall, or "larga barrera física," along the border.

"It goes without saying that integrating with the United States … is, and was, an essential

Continued on page 14

NYPSC Adopts 'Value Stack' Rate Structure for DER

By Michael Kuser and Rich Heidorn Jr.

The New York Public Service Commission on Thursday adopted a new "value stack" pricing mechanism for solar and other distributed energy resources, along with two other orders to transition utilities into "distributed system platforms" and align their incentives with DER providers.

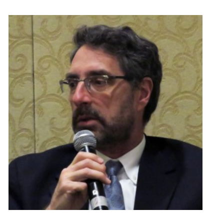
The Value of Distributed Energy Resources order approved March 9 (Case 15-E-0751) begins the transition away from net energy metering and toward an approach that aggregates specific value components. The number of those components will be raised

Continued on page 31

IMAPP Pondering 4 Options for Incorporating Clean Energy in NE Markets

By Rich Heidorn Jr.

AUBURNDALE, Mass. — Stakeholders are considering four proposals for making New England's markets more accommodating to state clean-energy initiatives, including a carbon adder in the energy market, potential changes to the capacity market and a possible new "clean energy" market.



David T. Doot, counsel and secretary to the New England Power Pool, outlined the changes to about 200 attendees at the Northeast Energy and Commerce Association's 2017 Renewable Energy Conference on March 6.

Doot said the four long-term proposals were narrowed from the 17 proposed over seven meetings of the Integrating Markets and Public Policy (IMAPP) initiative last year. Officials announced last month that IMAPP

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IN THIS WEEK'S ISSUE

RESISTANCE
BY STEVE HUNTOON

Microgrid Kool-Aid and National Security

The microgrid Kool-Aid keeps gushing out of the firehose. I wrote a while back about why microgrids are an irrational throw-back to the utility islands of the late 19th century.[1]

In a nutshell, microgrids cannot improve on the efficiency of centralized, least-cost dispatch. And in terms of adding reliability, authoritative case studies by the New York State Energy Research and Development Authority found that microgrids would make sense only if annual customer outage time was measured in *weeks*, rather than the reality of a couple hours.

Yet microgrid proposals continue to proliferate. Especially where subsidized with Other People's Money.[2]

This column focuses on a microgrid study involving our military bases.[3] This is important not only because taxpayer money is involved, but because our national security is involved.

This study, by a consultancy called Noblis, with assistance from ICF, concludes that replacing backup diesel generators at individual military buildings (the status quo) with diesel/natural gas microgrids at military bases would save money. Their concept is shown in the study's Figures 4 and 5.

The study includes an incredible amount of modeling and data, no doubt costing its sponsor, Pew Charitable Trusts, a ton of money.

Yet the study is *profoundly wrong*. The profound error is shown by this "Ownership of infrastructure" pie chart from a Government Accountability Office study,[4] showing who owns the infrastructure responsible for significant outages.

You can see that 87% of outages on military facilities arise on the military's own distribution systems. Microgrid generation would be dependent on these distribution systems to deliver electricity to individual buildings. Thus, microgrids would cause individual buildings to lose backup for 87% of outages — *eliminating the vast bulk of backup.*

How could such a profound error be made? The study wrongly assumed that distribution system outages aren't significant, saying: "Although inside-the-fence problems account for some (unknown) share of all outages, on-base problems can generally be solved through improved maintenance of the base and straightforward investments (e.g., keeping trees trimmed and putting wires underground)."

Instead, on-base problems account for 87% of all outages.[5] And if they were easily avoided, they would be.

In Rumsfeldian parlance, on-base problems are not a "known unknown," but instead are a "known known." The study's profound error was not recognizing this known known.

And another important national security consideration: cybersecurity. The Noblis study talks a lot about cybersecurity, but nowhere does it acknowledge that for microgrids to function as intended, they must have communications links with the greater grid, exposing them to the same cyber risks as the rest of the grid. Backup generators at individual buildings do not need any communication link outside the building.[6]

Beyond these two vital national security considerations, please note one other glaring oversight in the study. This one involves the estimated cost of microgrids.

The study goes through a lot of hypothetical numbers to come up with a capital cost of $17.4 million for a hypothetical microgrid of 24 MW, which works out to $725/kW.

Problem: The Defense Department's most recent microgrid project at Marine Corps Air Station Miramar in San Diego cost $20 million for 7 MW.[7] That works out to $2,857/kW, which is about 400% of the study's cost estimate. The study mentions the Miramar microgrid but somehow doesn't connect the dots to its project cost.

An ounce of fact is worth a pound of hypothetical.

And speaking of fact, the nation's "flagship" microgrid at the University of California, San Diego flunked its acid test in the Southwest Blackout of 2011. The campus shut down with the rest of San Diego.[8]

You can't make this stuff up.

In Rumsfeldian parlance, on-base problems are not a "known unknown," but instead are a "known known." The study's profound error was not recognizing this known known.

Steve Huntoon is a former president of the Energy Bar Association, with 30 years of experience advising and representing energy companies and institutions. He received a B.A. in economics and a J.D. from the University of Virginia. He is the principal in Energy Counsel LLP.

[1] http://energy-counsel.com/docs/Microgrids-Wheres-the-Beef-Fortnightly-November2015.pdf.

[2] Not all the news is bad. Pennsylvania's consumer advocates got PECO Energy to abandon a $35 million microgrid dalliance, and it appears hundreds of millions for Commonwealth Edison microgrids got cut from the Illinois Future Energy Jobs Act, approved in December, which provides zero-emission credits for Exelon's nuclear generators.

[3] http://noblis.org/media/b6a465e0-4200-42d8-9377-5f20251e52c0/docs/Environment/Power%20Begins%20at%20Home-%20Noblis%20Website%20Version_pdf.

[4] http://www.gao.gov/assets/680/671583.pdf. Figure 3: Disruptions lasting eight hours or longer in fiscal years 2012-14 as reported to GAO by 18 Defense Department installations inside and outside the continental U.S. The data include wastewater and potable water disruptions, but the vast majority of the disruptions are electric.

[5] This is consistent with outage causation outside of military facilities. About 90% are attributed to the distribution system, as opposed to the higher voltage transmission system. See http://www.eei.org/issuesandpolicy/electricreliability/undergrounding/documents/undergroundreport.pdf, Figure 3.3. (Compare the customer interruptions on the combined transmission/distribution system to interruptions on the distribution system alone). One driver of this is that the transmission system is designed with redundancy, so that if one element (a transmission line, a transformer, etc.) fails, there is no loss of service. The distribution system generally is not designed with such redundancy.

[6] Individual backup generators also would seem less vulnerable to electromagnetic pulses (EMPs) because they are simpler, not connected to the grid, and do not operate unless there is an outage. Noblis says that EMPs are "beyond the scope of this report" (footnote 10), which begs the question: "Why?"

[7] https://microgridknowledge.com/military-microgrid-projects/.

[8] http://www.eenews.net/stories/1059996047 ("The university's two 13.5-MW Trident turbines were running full-bore when power from the utility abruptly went dead. With no time to shed their load, the turbines also shut down, and the campus lost electricity.")

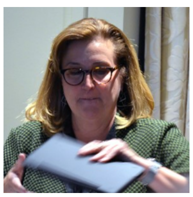
CAISO News

Western Stakeholders Support Continuation of EIM Regional Forum

By Robert Mullin

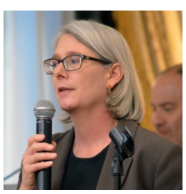
LAS VEGAS — The West-wide forum created by CAISO to foster discussion about Energy Imbalance Market-related issues outside the ISO's normal stakeholder process is worth preserving — and developing further.

That was the general consensus of stakeholders and EIM Governing Body members who gathered at The Palazzo hotel to discuss the fate of the Regional Issues Forum (RIF), which was established in 2015 as the ISO began to build momentum for "regionalization" — the push to expand into other parts of the West.



"We all value what the RIF has been doing," Governing Body Chair **Christine Schmidt** said during a Feb. 28 joint meeting that included fellow body members, RIF representatives, industry participants and interest groups. "We value the promise of what the RIF can do going forward."

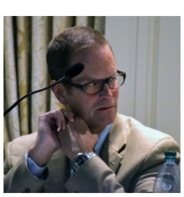
'Learning a Lot'



Speaking in her capacity as a Washington state utility commissioner, **Ann Rendahl** — chair of the EIM's Body of State Regulators — voiced her support for the RIF as someone "who is coming into this market new and learning a lot."

"The Regional Issues Forum discussions have been very helpful, because you are all participating in the market and you have experiences that are helpful for us to learn and hear, in addition to the formal stakeholder processes that the ISO puts on," Rendahl said.

Accolades notwithstanding, uncertainty still looms about the future role for the forum, what formal structure it should assume and how it should interact with the Governing Body.



Doug Howe, the body's vice chair, referred to it as "the existential question of 'What's the RIF?'"

RIF representatives, called "sector liaisons," have committed to answering that question and developing an operating framework for the group in time for the Governing Body's July meeting.

"The liaisons don't see a lot of barriers to getting this done in an expedited way," said **Tony Braun**, RIF chair and a liaison representing the publicly owned utilities sector.

Informal Body

The RIF was conceived under the EIM charter as an informal body to enable industry stakeholders and the public to discuss wide-ranging issues related to the West's only real-time energy market. (See *PacifiCorp Offers Lessons for Future EIM Participants*.)

The forum is organized by 10 liaisons representing five industry sectors: independent power producers and power marketers; transmission-owning utilities; publicly owned utilities; consumer advocates; and balancing areas neighboring the EIM — the last of which is a diminishing group as the EIM grows, Braun joked. CAISO planned for the RIF to meet about three times a year but required no set schedule.

According to the ISO, "The forum may produce documents or opinions for the benefit of the EIM Governing Body, ISO Board of Governors and the ISO," but it sits firmly outside established stakeholder processes.

The EIM's governance documents call for the RIF's role to be re-evaluated by next month, which was the primary reason for the Feb. 28 joint meeting.

Re-evaluation Process

A key question in the re-evaluation: How should the RIF run the process to re-evaluate itself?

"Should this be an ISO-run stakeholder process in the traditional fashion?" asked Braun. "Is this something that the liaisons should take ownership of? What should be the liaisons' role in putting together the recommendations and things like that, if any?"

Schmidt said she didn't think the RIF's evaluation was ever intended to become part of an ISO stakeholder process.

"I think the general consensus [among CAISO and EIM leaders] is that the Regional Issues Forum is the Regional Issues Forum," Schmidt said. "However the re-evaluation needs to take place, this is in your control and is in your span of control and authority, and you should actually go through that process as a Regional Issues Forum issue."

Speaking on behalf of her company, RIF liaison **Sara Edmonds**, general counsel at PacifiCorp Transmission, supported the general independence of the RIF, but she noted that the group has no funds or processes to post material coming out of its meetings.

"We're happy as the liaisons to kind of be the muscle to pull together the substance [of the re-evaluation], but we're still going to need the ISO vehicle to get the information out [and] help us with the meetings," Edmonds said.

Ellen Wolfe of Resero Consulting, representing the Western Power Trading Forum (WPTF), backed Edmonds' view. The WPTF sees "a lot of value" in the continuation of the RIF and agrees with the bottom-up approach to re-evaluation, she said.

'Grass-Rootsy'

"We do like the idea of the RIF being very 'grass-rootsy,' so to speak, but also appreciate the ISO providing the infrastructure for posting comments and market notices and so forth," Wolfe said.

Howe sought more clarity on the process the RIF would adopt in its re-evaluation.

"So we know that is not going to be a formal

Continued on page 5

CAISO NEWS

Western Stakeholders Support Continuation of EIM Regional Forum

Continued from page 4

ISO stakeholder process — which means a few things, but among them is that you're not going to start with an issue paper that's going to be delivered to you by the staff of the ISO," Howe said.

"So, to some extent, either you're going to have to deliver the issue paper, or you're going to have to take in the comments, perhaps write a strawman proposal, and send that out for another round of comments."

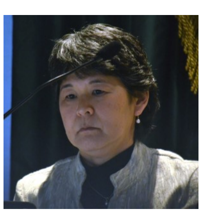
Howe wondered whether ISO staff would ultimately be charged with writing the strawman based on what RIF liaisons heard during the Feb. 28 meeting.

"In my mind, we're either fish or fowl," Braun responded. "So if this is a process that the RIF liaisons are going to take ownership of, then my colleagues as the liaisons need to pick up the pens and craft the issue paper of the first straw proposal."

"We're all devoting our time and energy to this because we think it's important," said RIF liaison Matt Lecar, principal at Pacific Gas and Electric. "But there is a lack of formal structure, and therefore a lack of funding and resources to do things like write the extensive issue papers and straw proposals that the CAISO staff otherwise would in a CAISO stakeholder process."

Hands Off

On the question of who should be responsible for approving the RIF's proposal for a framework, Governing Body members advocated a mostly hands-off position.



"I am not seeking to have authority over what the RIF does," said Governing Body member **Valerie Fong**, adding that she wouldn't want to be cut out of the RIF's activities because of the forum's education value. "I won't be offended if [RIF members] decide that the EIM Governing Body does not have a decision in this process."

Howe seconded Fong's sentiments, saying he didn't see a role for the Governing Body

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to put its "blessing" on the RIF's final proposal.

"The primary purpose of this [process] is to construct an organization that helps you all to be effective, and I just want to thank you for including us in that," Governing Body member Carl Linvill said. "But as far as any kind of formal approval, I'm with what everybody else has said: I don't think we need that."

Fellow body member John Prescott said it was important for the RIF to be transparent.

"What I want is access to the knowledge," Prescott said.

Schmidt reminded her fellow body members that the RIF is embedded in the EIM's governing documents, meaning that decisions around the RIF will still be subject to some CAISO oversight.

"If there's a resource impact, or any other impact on the ISO or the ISO's Tariff, those are matters that will have to be decided by the EIM's Governing Body and ultimately the [ISO's] Board of Governors," Schmidt said.

RIF as Author?

Another key issue facing the RIF: whether it will produce papers on issues coming before the EIM Governing Body.

On that subject, Braun said stakeholder comments ranged from "no, that's not what the RIF is for" to "yes."

Howe said the question must be preceded by what issues the RIF will undertake.

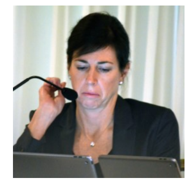
"Are you going to take on issues in the stakeholder process?" Howe asked. He added that the RIF will "need to decide how you're going to decide."

Fong noted that operating guidelines are "somewhat silent" on a lot of RIF issues.

"If I were you, I would keep my options open," she said.

'Happy to Help'

Lecar wondered if there would be resources available to the RIF to take on larger written work projects.



Stacey Crowley, CAISO vice president for regional and federal affairs, affirmed that ISO staff would be willing to take down comments from a RIF meeting.

"We're happy to help," Crowley said, adding that it would be up to the RIF, however, to craft substantive policy recommendations.

Howe emphasized the need for the RIF to document the views arising within its discussions. "If you don't turn this into a written product, these are conversations that get lost in the dark," he said.

Jennifer Gardner, staff attorney with Western Resource Advocates, asked whether the RIF could play the role of flagging issues for the Governing Body that are not already being addressed in CAISO's stakeholder process.

"Is there value, from the Governing Body's perspective, in having something a little bit more formalized with the RIF?" Gardner asked. A more formal process would entail producing written comments, rather than just "casual dialogue" among RIF participants.

"Does the RIF have to come to consensus on everything?" Fong asked. "Does it have to be giving us an overall perspective from a RIF level? I'd say 'no.' I'm OK with the individual input" from RIF participants.

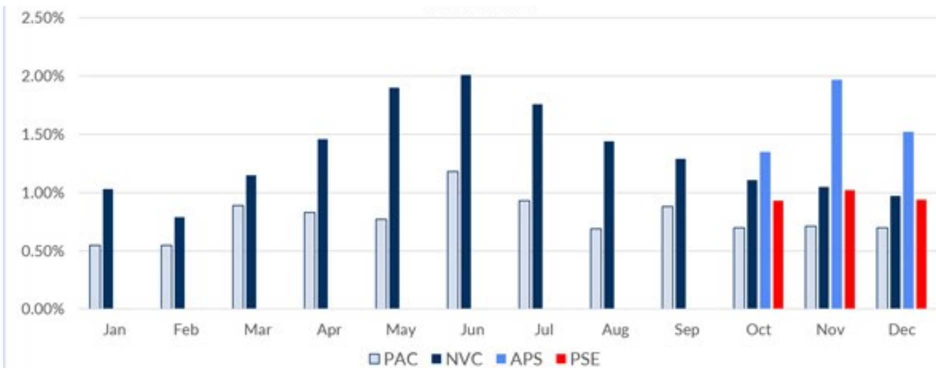
Howe agreed with his colleague and added his own perspective.

"For me, the value is the eyes and ears out in the field to flag issues which may not have risen to the level [of] the ISO yet," Howe said. "What doesn't have value for me would be for the RIF to try to turn itself into a formal stakeholder process, because we've already got that [within the ISO]. And that just wouldn't provide additional value."

CAISO NEWS

Behind-the-Meter Generation Complicating EIM Load Forecasting

By Robert Mullin



Graph shows the hour-ahead load forecast error rates for the EIM balancing areas outside CAISO during 2016. APS errors have outpaced those of other regions since the utility joined last October. | *CAISO*

LAS VEGAS — Increased adoption of behind-the-meter generation is complicating short-term load forecasting across the Western Energy Imbalance Market (EIM), especially in the Arizona Public Service area.

The challenge is caused by the unpredictability of cloud cover, which can cause sharp and sudden drops in solar production.

"In the past, cloud cover was always a variable that came in for load forecasting, but it was really interrelated to temperatures," Amber Motley, CAISO manager of short-term load forecasting, said during a March 1 meeting of the EIM Governing Body at The Palazzo hotel.

The conventional understanding: Clouds would move over an area, causing temperatures to fall, which would in turn reduce system load.

"Now, when you get high penetration levels of rooftop solar, there is a point in time when clouds come over and your [net] load is going to increase instead of decrease" because of reduced output from rooftop solar, Motley said.

A Caveat

Motley offered one caveat to that assessment: When daily temperatures average about 80 degrees Fahrenheit, temperature is still the main driver of the load forecast.

Under those conditions, air-conditioning load still drives enough electricity consumption that a cloud system causing a 10-degree drop in temperatures is going to reduce load.

Further complicating matters is humidity, which causes air conditioners to work harder and support load even under cloud cover. The situation is especially problematic in summer when monsoon moisture is thrown into the mix.

"You really have a question to ask yourself: Is my load going to increase because I am losing the rooftop solar, or is it going to decrease because I have a 10-degree temperature drop?" Motely said. "And we've seen both situations happen."

Motley called APS the "most challenging load-forecasting region" within the EIM.

"It has a combination of a significant amount of rooftop solar, which is a driving factor, combined with some of those strong monsoon days in the summertime," she said.

APS began transacting in the EIM last October, after the summer solar and monsoon peaks. But CAISO began running EIM load forecasting models ahead of the go-live date, giving operations staff an indication of what to expect this summer.

High Error Rates

So far, even outside the summer months, short-term load forecasts for the APS area are recording relatively high error rates compared with other EIM balancing areas (see chart). In November, the region's hour-ahead forecast error rates reached nearly 2%, falling to 1.5% the following month. NV Energy has had similarly high error rates in the summer because of the prevalence of dust storms — a phenomenon that affects Arizona as well. The error calculations represent the average deviation between hour-ahead forecasted load and actual load.

The ISO's goal is to keep error rates below 1%, Motley said, adding that such accuracy is not always attainable in some regions.

"If you have more rooftop solar, your accuracy is going to be worse because you now have another characteristic behind the scene that is influencing it," Motley said.

She pointed out that short-term load forecasting is an important component for market optimization and reliability. It also is used as a key input for dispatch operation functions such as unit commitment, economic dispatch, fuel scheduling and generation and transmission maintenance.

EIM Governing Body member John Prescott wondered if there was a "nexus" between load forecasting errors and the high number of flexible ramping test failures observed in the EIM late last year — particularly in APS. (See EIM Sees Sharp Increase in Flexible Ramping Test Failures.)

"There are several factors that play into that and we have to isolate each one to see what's driving it," said Justin Thompson, director of resource operations and trading at APS. "But load forecast is one piece of it. Also, how well have [we] forecasted wind? … How well [have] we forecast the solar

"You really have a question to ask yourself: Is my load going to increase because I am losing the rooftop solar, or is it going to decrease because I have a 10-degree temperature drop? And we've seen both situations happen."

Amber Motley, CAISO

Continued on page 7

CAISO News

CAISO Seeks Reliability Designations for Calpine Peaking Plants

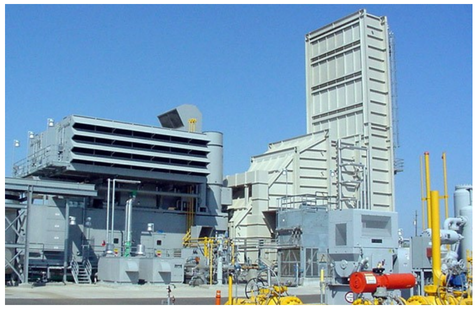
By Robert Mullin

CAISO wants to use an out-of-market measure to keep two Northern California gas-fired peaking plants operating after their long-term contracts expire in December.

The ISO is seeking to designate Calpine's Yuba City and Feather River plants as reliability-must-run resources after identifying that both 47-MW peakers will be needed to support local grid reliability after they fall off their current contracts with Pacific Gas and Electric, which manages the service territory where the plants are located.

The issue arose last November when Calpine notified CAISO that expiring operating agreements would require the company to shut down four of its combustion turbine peakers.

Calpine asked CAISO to study whether loss of the units would cause grid reliability problems. The company said that its capital outlay and resource planning requirements required that it learn of any reliability need for the plants before this fall, when the ISO would release its 2018 resource adequacy assessment. Such a determination would make the plants eligible for longer-term resource adequacy payments under CAISO's capacity procurement mechanism (CPM).



Yuba City | *Calpine*

"On that basis, we did do the review that was requested and concluded that there is a reliability need for two of the four generators," Neil Millar, CAISO executive director of infrastructure development, said during a March 7 call to discuss the issue. Two plants farther to the south, King City and Wolfskill, failed to make the cut.

Pease Area Deficient

Under an RMR arrangement, CAISO has the right to call upon a generator to provide energy, black start services or voltage support to meet reliability needs. The ISO compensates the generator for keeping capacity available for dispatch, with costs allocated to benefitting load-serving entities.

"Without the 47 MW from Yuba City, we would be deficient" in the Pease local capacity requirements sub-area, Millar said.

The ISO performs an annual analysis to determine each local area's minimum capacity requirement to meet reliability

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Behind-the-Meter Generation Complicating EIM Load Forecasting

Continued from page 6

output?"

Phoenix Baseline?

Alyssa Koslow, a regulatory analyst at Salt River Project, said she had heard CAISO was using Phoenix as the baseline for forecasting for Arizona, despite the fact that APS's territory extends into high-elevation areas.

Motley clarified that the ISO's approach to forecasting is more comprehensive than that.

"We have multiple temperature stations within Arizona, and [the load forecast] is always driven by the temperature station that's closest to where your load pattern moves the most," Motley said. "So we work with all of the EIM entities on which station in which area moves the most for your load and then we incorporate that into the design."

"One of the problems with models is 'garbage in, garbage out,'" said Clay MacArthur of Deseret Power. "There's a lot of behind-the-meter generation going on. How do you aggregate" the capacity?

Motley responded that the ISO takes a bottom-up approach that starts with the zip code and capacity for every interconnection on the distribution system. That information lays the foundations for system load forecasts for individual areas.

"And then we forecast the irradiance — which is essentially the amount of sunlight that's going to come from the atmosphere to the roof for that resource — and we put that into the forecast as its own variable," Motley said.

Neural Net

That last point is important for CAISO's "neural net" forecasting method, which relies on the dynamic interplay between "highly interconnected processing elements" — the data fed into the model. As Motley explained, the neural net is modeled on the human brain and can synthesize copious amounts of information and "learn" to weight the importance of certain factors over others in their predictive processing.

"Storing the information by technology type is very important so that the neural net can have the correct connections," Motely said. If that information gets "blended in with the rest of the model," then the neural net has a difficult time distinguishing whether it was a change in temperature or solar output that caused load to move up or down.

CAISO continues to seek ways to improve its load-forecasting model, Motely said. Future improvements could include having EIM participants share their own load forecasts to provide comparisons, as well as having them provide balancing area information about demand response, hydroelectric behavior, rooftop solar and irrigation patterns.

"Can we fix everything? No, it's forecasting — it's good job security," Motley joked. "But are there some things that we can fix? Yes, there are some things."

CAISO NEWS

SMUD Balancing Area Inks Agreement for EIM Membership

By Robert Mullin

The Balancing Area of Northern California (BANC) has signed an agreement with CAISO that puts the Sacramento Municipal Utilities District (SMUD) on track to join the Western Energy Imbalance Market (EIM) in spring 2019.

The implementation agreement comes four months after SMUD entered negotiations to join the West's only real-time energy market — making it the first publicly owned utility to do so. (See *Sacramento Utility to Join EIM; Other BANC Members May Follow*.)

Another municipal utility, Seattle City Light, announced its interest in joining the market shortly after SMUD's announcement and has already signed an agreement with the ISO, putting it on schedule to join up at the same time as the California utility. (See *Seattle City Light Signs EIM Membership Agreement*.)

The latest agreement calls for a "phased" approach for BANC members to join the EIM, with SMUD's participation representing the first stage, followed by discussions regarding participation for other members, possibly including federal power marketing agency Western Area Power Administration's Sierra Nevada region.

Regardless of whether WAPA eventually links up with the EIM, BANC members Modesto Irrigation District and the cities of Redding and Roseville are considering doing so. Two other members — the city of Shasta Lake and Trinity Public Utilities District — own no generating resources and would therefore derive no benefit from joining the market, according to Jim Shetler, BANC's general manager.

The phased implementation hinges on SMUD being accounted for separately from other BANC members, including "having separate interchange as represented by e-tags, a separate area control error calculation, and separate revenue quality metering," the EIM agreement states.

SMUD already has an agreement that enables the utility to bid power into CAISO through a single hub in which one proxy price is selected to represent all connection points between the two areas.

Another term spelled out in the agreement: CAISO acknowledges that as public entities, BANC members want to remain outside the jurisdiction of FERC.

BANC, in turn, accepts that its transmission-owning members will be required to amend their open access transmission tariffs to reflect the fact that the EIM's operations are subject to FERC oversight.

"We believe the implementation agreement and our partnership with [the] ISO recognizes the unique situation of our public power members," Shetler said in a statement. "We are pleased to begin the work that will enable our members to participate in the EIM if they choose to do so."

Incorporation of other BANC members in the future will require that the agreement be amended, or that a completely new one be executed.

CAISO CEO Steve Berberich said he was pleased with the decision by BANC and SMUD.

"SMUD is one of the premiere community-owned utilities in the country that will benefit from access to low-cost resources from the entire EIM footprint," Berberich said.

SMUD has cited the benefits of increased renewable integration, potentially reduced reliance on gas-fired generation and lower operational costs as its primary reasons for joining the market — although the first two benefits outweighed the latter in the utility's decision-making, according to Shetler. A joint study conducted by BANC and the WAPA estimated that SMUD would gain $2.8 million in yearly net benefits from transacting in the market, possibly increasing to $5 million in about five years — a "small number" compared with the utility's overall portfolio, he said.

Established in 2011, BANC is the third largest balancing area in California and the 16th largest of the 38 balancing areas in the Western Electricity Coordinating Council. The agency contracts with SMUD to perform day-to-day balancing functions.

CAISO Seeks Reliability Designations for Calpine Peaking Plants

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standards. Other generators can provide only 82 of the 100 MW required in Northern California's Pease sub-area, leaving the Yuba City unit to make up the difference.

Feather River is not needed to supply capacity, but the plant does play a key role in controlling voltage in its surrounding region by absorbing reactive power from the system. Without the unit, 115-kV bus voltages in the area would rise to "significantly beyond" the upper limit of the normal range, CAISO has found.

"We will be looking at longer-term mitigation in that area in future transmission planning process cycles," Millar said. "We're working with PG&E, and also recognizing that this is a combination transmission and distribution issue."

Millar pointed out that a one-year RMR designation would not prevent the plants from entering into longer arrangements with the ISO if the need is identified.

"Just because the units may be designated as reliability-must-run in the spring [of 2018], [that] doesn't preclude them getting some longer-term resource adequacy contract that would obviate all or parts of the need for an RMR agreement," he said.

Carrie Bentley, a consultant representing the Western Power Trading Forum, wondered why the two plants wouldn't be covered under the ISO "risk-of-retirement" CPM.

"I understand that they can't wait for the annual, but I thought that the risk of retirement didn't have such timing issues," Bentley said.

"It's not totally within the ISO's ability to direct that," said Sidney Mannheim, CAISO assistant general counsel. "The CPM is

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CAISO NEWS

Report Shows Continued Losses in CAISO CRR Auctions

By Robert Mullin

CAISO last year paid out $47 million more to congestion revenue rights holders than it took in from its auctions, the ISO's internal Market Monitor has found.

That deficit — a persistent problem since the ISO instituted CRR auctions five years ago — could buttress the Monitor's call for ending the auctions, which it says allows financial speculators to reap hundreds of millions of dollars at the expense of California electricity ratepayers. (See *CAISO Monitor Proposes to End Revenue Rights Auction*.)

"The [Department of Market Monitoring] believes that the trend of revenues being transferred from electric ratepayers to other entities warrants reassessing the standard electricity market design assumption that ISOs should auction off these financial instruments on behalf of ratepayers after the congestion revenue right allocations," the Monitor said in its quarterly market issues and performance report covering the fourth quarter of last year.

The Monitor's suggestion: Replace the auction with a bilateral or exchange market for contracts-for-differences for pairs of ISO nodes — also known as locational basis price swaps.

Under that arrangement, swaps would be traded among willing counterparties, rather than leaving ratepayers as unwitting parties in a market in which they are outmatched by more sophisticated traders, the Monitor says.

CAISO management has responded to the Monitor's concerns by agreeing to consider a stakeholder initiative on potential changes to the auction, a move that has been met with mixed reactions from market participants. (See *CRR Initiative Elicits Mixed Reviews from CAISO Participants*.)

Proposal Unwarranted?

"While I don't believe DMM's latest findings warrant their specific proposal to replace the CRR auction with a bilateral market or locational price swaps … I think the CAISO's study is absolutely an opportunity to make improvements to the current CRR auction and identify practices and transparency issues that may be causing some inefficiency in the CRR auction pricing," Carrie Bentley, a principal with Resero Consulting, told *RTO Insider*.

Bentley's firm frequently works on behalf of the Western Power Trading Forum (WPTF), an energy trader interest group that opposes the suggestion to scrap the auction. It has called the proposed stakeholder initiative a "pet project" of the Monitor.

The Monitor's most recent findings show that last year's CRR deficit increased by $1 million over 2015, with auction revenues

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CAISO Seeks Reliability Designations for Calpine Peaking Plants

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voluntary on the part of the resource owner, where [with] the RMR authority, we literally have the Tariff authority to designate a resource as RMR."

Impact on Local Capacity Requirements

Erica Brown, senior analyst with PG&E, asked about the impact of the RMR designations on local capacity requirements.

"So, going into our next [resource adequacy] year, if there's an RMR resource [in a local area], would that subtract from the overall quantity that's needed for the local area?" Brown asked.

Millar clarified that the Yuba City plant would count toward the area's capacity requirement because the unit's RMR designation would be based on a capacity need, while Feather River, which is needed for voltage support, would not.

Michele Kito, a regulatory analyst at the California Public Utilities Commission, asked about Calpine's need to make investments in the peaking units to keep them online next year. "At what point would there be some independent engineering assessment that those long-term investments need to be made that would justify a long-term RMR agreement?" she asked.

Mannheim clarified that the RMR agreements would only run year-to-year, although they could ultimately cover a multiyear need.

"The RMR process does involve the responsible transmission owner and the PUC to review any proposed capital improvements," Mannheim said. "That is the process we would undertake following any designation — and the PUC would be involved in that."

CAISO plans to present the Yuba City and Feather River RMR designations for approval by the Board of Governors on March 16. Upon approval, Calpine would be expected to draw up a cost-of-service proposal, including any capital improvements, for review by PG&E, the ISO and the PUC.

CAISO NEWS

Report Shows Continued Losses in CAISO CRR Auctions

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representing just 68% of CRR payments made to auction participants, compared with 73% during the previous year.

While total payments to auction rights holders declined 15% to $147 million, auction revenues also fell 21% to $99 million year over year.

Financial traders last year took in $33 million from the auctions, paying 63 cents for every dollar made from their CRRs. Their overall take was down 30% from the previous year, but it still represented the largest share of all participants. The Monitor has contended that "purely financial entities" are the main beneficiaries of the auction program.

Power marketers saw their auction profits increase by 43% to $10 million, while generator profits fell by 29% to $5 million.

Load-serving entities, which CAISO provides an annual allocation of CRRs, made about $3 million from rights they sold into the auction, down sharply from $14 million earned the previous year.

Transmission congestion dropped last year as drought conditions resulted in decreased electricity use for moving water supplies across California. Transmission usage also was undercut by growth in behind-the-meter rooftop solar.

The fourth quarter saw the resumption of the prevailing pattern of CRR payments outpacing auction revenues, following a short-lived surplus during the third quarter (see chart).

WPTF Comments

In comments filed with CAISO earlier this year, WPTF contended that auction revenues increased as a percentage of payments in the third quarter after the ISO implemented practices that improved transparency into how it represents transmission outages in its market models.

"I think the fourth-quarter results were due to unexpected transmission outages and nomograms [prediction tools] that were not included in the CRR model or known by participants in advance of the auction," Bentley said.

She cited as evidence the ISO's own monthly market performance reports for October, November and December, which attributed at least a portion of auction revenue shortfalls each month to unexpected binding constraints on the transmission system.

Unlike other RTOs that have imposed penalties for "late, unnecessary or nonemergency outages that impact the day-ahead market, but were not modeled in the monthly auction," CAISO has no such policies, Bentley said.

"Therefore, events like this last quarter are frequent, where outages impact CRR shortfalls with no repercussions on those causing the shortfall," she said.

Bentley added that the ISO may compound the issue by not providing sufficient notice in advance of auctions about nomograms created to account for outages.

"While the majority of nomograms understandably may not be done in advance sufficient to notify market participants, a tightening up of transparency policies would enable better CRR auction outcomes in those cases that the CAISO could have given advance warning," Bentley said.

Analysis Challenged

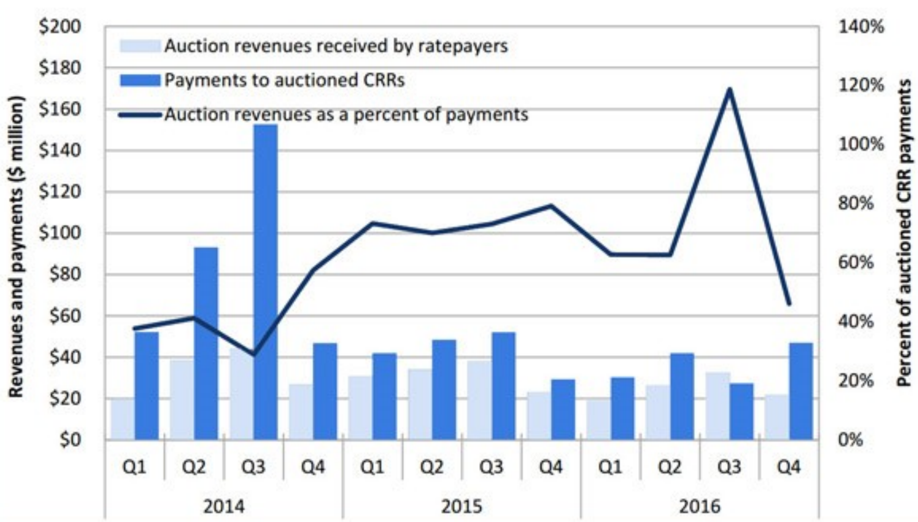
Ryan Kurlinski, manager of the Monitor's analysis and mitigation group, rejected Bentley's analysis. "There is no evidence to support WPTF's suggestion that improvements in the ISO's transmission outage reporting accounted for the reasons that CRR auction revenues exceeded payouts during the third quarter of 2016," he said.

Kurlinski said the third quarter was "very anomalous" and that lower payments to auction participants stemmed from "unusually low" congestion appearing in the ISO's day-ahead market during the period.

"During periods of this quarter, virtually no congestion appeared in the day-ahead market," Kurlinski said. "DMM is working with the ISO to understand factors which might have caused this." That lack of congestion likely accounts for last year's overall drop in payouts to CRR holders.

Kurlinski doubted that adjustments to the auction model could ultimately improve outcomes for ratepayers.

"Even if the CRR auction model includes all outages known by CAISO [transmission owners] at the time the model is completed, there will be outages that cannot be adequately modeled," Kurlinski said. "For instance, if an outage is scheduled for only a few days, this outage cannot be accurately represented in the monthly CRR model."



CAISO's congestion revenue rights auction revenues have consistently come up short of payments to rights holders, leaving ratepayers to foot the difference. | *Q4 2016 Report on Market Issues and Performance, March 6, 2017; CAISO Department of Market Monitoring*

ERCOT News

Overheard at the Infocast ERCOT Market Summit 2017

AUSTIN, Texas — Infocast gathered industry experts in the Texas state capital to share their insights on the "challenging times that lie ahead for ERCOT." Panelists examined changing market rules, the impact of gas prices on generators, how the delivery of new wind and solar power will change market dynamics, and the revamping of ancillary service market rules during the sessions Feb. 27-March 1.

PUC Trying to Balance Wind, Fossil Fuels

Donna Nelson, chairman of the Public Utility Commission of Texas, said the state's competitive market has benefited from lessons learned in California, which opened its electric market to choice in 1998, four years before ERCOT did the same. That has helped the PUC, which oversees the Texas grid operator, to prepare for the 28.6 GW of wind capacity sitting in ERCOT's interconnection queue.

"Right now, I'd say our market is working because we have a healthy reserve margin and we have fossil-fuel generation to cover [wind energy's] variability," Nelson said. "Over time, if that [wind] generation is built, we'll have to look at what it takes to keep the fossil fuels on. There's a tension between the workings of the competitive market and reliability. We've made a lot of adjustments to the market over time — we want to keep the lights on too — but we have to look at reliability from a short-term to long-term perspective. That's something the commissioners will continue to watch."

Nelson recalled a time when integrating 10,000 MW of wind power into ERCOT was considered an "iffy" proposition. "So here we are at 18,000 MW," she said. "That's a lot of investment, but lest you label me a renewable hater, it's made because of the [Production Tax Credit]. When you see other forms of fossil fuel generation is not invested, you ask, 'Why is that the case?'

"The PTC provides an incentive of $23/MWh. When you look at the average price of power in the ERCOT market, you can see an incentive of $23/MWh has the potential to distort the market," Nelson said, noting the ERCOT market prices energy based on the amount of generation needed. "If wind bids in at a low price at night, that sets prices in the early morning hours. It's gotten to the point where [the fossil-fuel plants] generate all their revenue in the summer. You're going to see less and less of that. You'll see wind lowering the price in the summer, as well."

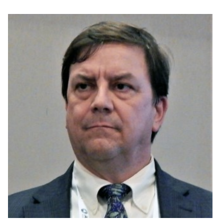
Over time, she said, that will lead to further retirements of fossil-fuel plants. "We won't have the fossil-fuel generation to back up wind's variability."

Dealing with Low Gas Prices in the ERCOT Market

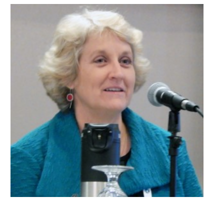
Several panelists discussed ERCOT's low power prices, their effect on the generating fleet, and forecasts for the future. The ISO's $24.64/MWh average price in 2016 was the lowest since the market opened in 2002. Natural gas accounted for almost 44% of ERCOT's power last year, with coal accounting for 29%, wind 15% and nuclear 12%.

Bob Helton, Dynegy's director of market design and policy for Texas, said he doesn't expect to see much of a rise in natural gas prices any time soon. "We know the administration is not going to stop fracking … take that for a given. We're going to have low [gas] prices in the future," he said.

That will put further economic pressure on ERCOT's coal units, which have been struggling to compete in the market.



"If prices are low, it's cheaper to buy off the market … than burn our coal plants," said **John Bonnin**, vice president of energy supply and market operations for San Antonio's CPS Energy, which plans to retire 950 of its 2,300 MW of coal capacity in 2018. "We went through 54 days without burning a single lump of coal last year."



While Bonnin also said "there's still a place [for coal capacity] in the summer," Potomac Economics' **Beth Garza**, director of the ERCOT Independent Market Monitor, pointed out much of Texas' coal fleet was built between 1975 and 1980.

"We're now in 2017. That would seem to be an economically rational life span for many of these assets," Garza said. "They're going to run until something big breaks, and it just won't get fixed."

Manan Ahuja, senior director of North American power for S&P Global Platts PIRA, said nuclear units are also at risk in the ERCOT market. "Would these potentially be retired?" he said. "These nuclear units have not made money in the last couple of years. Reliability issues apart, we think the economics are certainly under threat, though they are down in the pecking order as compared to some coal and gas-peaking units."

ERCOT: Not Really that 'RUCed Up'

Garza's recent comment that the Monitor considered 2016 to be "all RUCed up" came up again during the week, once by Garza herself. But were ERCOT's reliability unit commitment activities — a near quadrupling to 269 "unit days" — last year really that egregious? (See "IMM Year in Review: Low Prices, Windy, Lots of RUC," *ERCOT Board of Directors Briefs*.)

"I don't get bent out of shape about the RUC activities," said ERCOT COO **Cheryl Mele**. "I think the operators are doing a good job" reducing the impact on market prices.

"A lot of RUC is a sign the market is working very effectively," said ERCOT's **Resmi Surendran**, senior manager of whole-

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sale market operations and analysis. "If we give the [RUC] instructions, we're looking more holistically at the whole system. The ERCOT market design gives the right incentive to participate in the day-ahead market."

Surendran said the ISO's total net make-whole payments for the last five years has been almost $40 million — the same amount as PJM's monthly make-whole payments. (However, PJM's energy and capacity market has a peak load of 165 GW, more than double ERCOT's energy-only 69 GW.)

Last year, $1.2 million in make-whole was paid to entities that were short generation and another $1.4 million clawed back from generators with offers in the day-ahead market.

While the number of RUC events still concerns Garza, she agreed the financials tell a different story. "Even with the [RUC activity] increase, the cost of doing that … seems to tell me that, yeah, we had a bunch of RUC activity, but I don't think it was all that inefficient," she said.

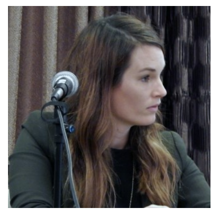
Wind Subsidies Distorting the ERCOT Market?

Appearing on a panel addressing "collapsing" power prices, NRG Energy Director of Regulatory Affairs **Bill Barnes** said ERCOT's market is "energy-only in theory" and that "subsidized wind generation" is a problem.

"What we have in ERCOT is very different [from energy only]. It's been released into the wild, and a lot of things are exerting influence over it," Barnes said. "NRG invests in renewables. We believe in renewables, but those that stand on their own two feet. We're beginning to see the impact of those subsidies on the market today."

Hannes Pfeifenberger, a principal with The Brattle Group, argued combined cycle plants with low heat rates and improved technology have done more to depress prices than wind energy.

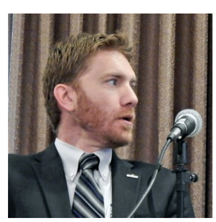
"We've seen technology costs being reduced so quickly that by the time the PTCs expire, these technologies will be in the market no matter what," he said. "One thing we have to realize is that baseload will be less valuable in the future, no matter whether the PTC expires or not. More flexible plants will be a market outcome. We will see more retirements because gas prices will remain low."



"There aren't price signals right now to build [baseload] generation because we have excess reserves. That's market 101," said **Katie Coleman**, a partner with Thompson & Knight. "I agree with Bill that the PTC and the proliferation of wind is a problem. Anytime you introduce subsidies into a market, you have distortions. Potentially assigning some transmission costs to wind, assigning ancillary costs to wind … those are things I think merit further conversations."

"This market can solve its problems," said **Philip Moore**, vice president of development for Lincoln Clean Energy, who linked the low prices to natural gas and wind. "ERCOT has shown an amazing ability to address the oncoming wind and its own transmission problems very efficiently. ERCOT will find ways to accommodate the energy-only market."

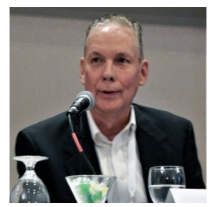
Solar Envy



While a potential flood of new wind energy has grabbed much of the attention, additional solar power is coming over the horizon, too. **Charlie Hemmerline**, executive director for the Texas Solar Power Association, said 2016 was the solar industry's best yet, with 14.8 GW of additional installed capacity creating a 42.4-GW total nationally. Texas ranks ninth nationally with 1,215 MW of capacity.

ERCOT, which almost doubled its solar capacity to 556 MW last year, could see another 2 GW come online by 2021. "Twenty other states have significant solar activity, which means there's heavy competition attracting people to the state of Texas," Hemmerline said. "We're in the mix, but we're not leading the pack. Our real focus as an industry is to make sure we can make that happen. Our legislative ask of folks is to do no harm. Let's not do anything to stop this investment or remove anything that would harm us along the way."

Much of Texas' utility-scale solar can be found in the wide-open spaces of West Texas.



"The thing we like at ERCOT about West Texas solar is it's a time zone away from our load centers," said **Paul Wattles**, the ISO's senior analyst for market design and development. "If you're generating in Pecos County at 2 or 3 in the afternoon, it's serving peak load in Houston," he said. "I think you will see more intelligent siting. I think you will see them to where they can make a lot of money during the critical part of the day."

Residential solar is playing an increasingly large role in the market as well. Wattles said Oncor just passed 10,000 rooftops, thanks in part to what he calls "solar envy."

"I hear Plano is going crazy" with installations, he said, referring to the Dallas suburb. "Those numbers are dwarfed by California, but it's something that wasn't there 10 years ago."

"Solar envy is definitely a thing," Hemmerline said. "As people see it, they want it too. [Residential solar] has been here a long time as a someday concept, but when you're seeing more of your neighbors doing it, it's propagating to where the costs make it a reasonable decision."

ERCOT is paying attention. "Solar is going to start commanding a larger share of the [distributed generation] fleet," Wattles said. "My group is concentrating on the big stuff right now, but the little stuff is coming really fast."

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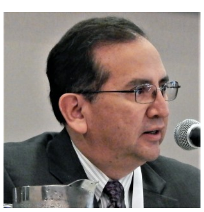
CREZ Project has Benefits, but Stability Issues

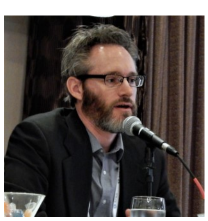
ERCOT's Competitive Renewable Energy Zones (CREZ) project resulted in 3,600 miles of transmission carrying 18.5 GW of West Texas and Panhandle wind energy east to urban load centers at a cost of $6.9 billion. The wind industry's growth also led to $38 billion in investment across 60 Texas counties and almost 23,000 jobs, according to **Susan Williams Sloan**, vice president of state policy for the American Wind Energy Association.

"It's a testament that CREZ brought a lot of benefits to the state," Sloan said, adding it has also yielded $60 million in annual lease payments to rural Texas landowners. "It's a new crop for landowners, and allows them to have a passive income. Over the years, there's even been some landowner wind associations formed to attract wind to their community."



"We don't have all our wind in West Texas anymore," said Sharyland Utilities' **Bill Bojorquez**. "We have wind in the south, in the Panhandle and coastal. We don't have wind peaking at the same time of the day."

Increasingly, that remote wind generation has led to some stability problems on the ERCOT grid.



"Traditionally, we saw thermal issues. That was the main thing we had to operate and plan around," said **Jeff Billo**, ERCOT senior manager of transmission planning. Now, he added, "We're seeing generation that's more removed, and we're seeing more asynchronous generation."

Fossil Fuels Still Viable Alternatives

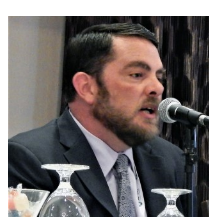
Golden Spread Electric Cooperative COO **J. Jolley Hayden** said his company is moving away from power purchase agreements to quick-starting gas units because of market dynamics. "As the markets get more robust, that's the resource we're looking at," he said.

Using aircraft carriers (coal plants) and PT boats (quick starters) as images, Hayden said, "The big aircraft carriers … if they're in organized markets, they're struggling right now. They're running, and they're out of the money. The PT boats' flexibility is essential. The more dynamic the market is, the more flexible you have to be to keep your costs low."

Coal resources still have their supporters, however. **Ingmar Sterzing**, vice president of power supply and energy services for Pedernales Electric Cooperative, said coal plants "absolutely" still provide a benefit and their potential value is not priced in the market.

"It's physical fuel that's available at the plant, with a supply of 45 to 60 days. That's unlike any other resource in ERCOT except nuclear," Sterzing said. "If you're really in a pinch, coal is there and it's available. It's very reliable. Once those coal plants are gone, it's going to be very difficult to bring them back. You try permitting a new coal plant, and it's eight to 12 years. You're going to be stuck with a limited set of options."

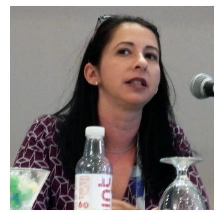
Customers More Informed, Still Hard to Move



Mark Bruce, one of the architects of Texas' competitive market and principal with Cratylus Advisors, said he is "tickled pink" to see his vision become reality. "The stakeholders wanted to empower customers to become more efficient and make their own decisions," he said.

But challenges remain.

"We're seeing sluggish [load] growth. Efficiency is creeping in as customers get more information. They are putting their own generation behind the meter, using storage, getting familiar about time of use. There are more bears in the woods. Our old models don't fit with the way this is going."



Michele Gregg, director of external relations for Texas' Office of Public Utility Counsel, reminded attendees not to forget about retail customers. "We need to remember customers want to spend very little time on electricity," she said.

"We spend a lot of time in industry meetings talking about what innovation they need … what the customers want and reducing load. The average customer has no idea what load is. They get a bill once a month, they know that bill is too high. In the retail market, the [retail electric provider] is the only one they want to do business with."

The bills may be high, but the customers still tend to stick with their legacy providers. TXU Energy, which dominates north and central Texas, has seen its rate of departing customers drop from 8% in 2010 to 1% in recent years.

Asked how he would crack the TXU and Reliant Energy legacy markets, **Andrew Elliott**, director of supply and portfolio management for ENGIE Resources, did not have a ready answer.

While the retail market is not in his purview, Elliott offered up a story involving his mother-in-law. He said he tried to explain to her she had her choice of retail electric providers, but she would have none of it. "'This is my electric company. I've always paid them.'

"We would love to have the holdover customers," Elliott said, before repeating the original question. "So how do you crack

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ERCOT NEWS

Trump Casts Shadow over Growing Mexican Market

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assumption of the reform," Villarreal said. "But recent political changes have put that into question."

Mexico already has five DC ties with the U.S. — three across the Texas border and two with California — with a total capacity of 1,086 MW. Another eight interconnections provide an additional 788 MW of capacity of emergency power.

Mexico's natural gas market is just as integrated, with more than a dozen pipelines connecting with the U.S.

Noting that he is not part of Mexico's negotiating team with the U.S., Villarreal told *RTO Insider*, "The idea is to find a way for both countries to keep on having a positive relationship with respect to energy trade. The underlying assumption is this will still happen."

But Villarreal also thinks there's now a "wild card": Changes to the free-trade agreement between the two countries could result in "strange consequences" — such as a "very onerous" process for permitting gas exports south of the border.

The Comisión Federal de Electricidad (CFE), the government electricity monopoly, has been broken up into seven generating subsidiaries, which bid into the day-ahead market along with several international generators. Those independent producers include Spain's Iberdrola and Global Power Generation and several new Mexican companies, and could potentially include American generators.

Villarreal

"Some very large [American companies] that you're very well aware of … will be transacting in the market very soon," Villarreal promised. He pointed out that LMPs in Mexico are double those in ERCOT, which averaged $24.62/MWh last year, and said a "very healthy price differential" has been driving flow from Texas across DC ties that are "half-used" during summer's high demand.

Mexico's forecasted load growth can serve as a buffer for ERCOT's oversupply and aggressive wind program, Villarreal noted.

"It's money lying on the floor," he said. "Someone has to pick it up. It's going to go away as people come into the market."

Gas trade between the two countries is much more mature, and Mexico is a natural sink for the U.S., Villarreal said, noting that his country's supplies are rapidly being depleted and are bedeviled by high quantities of nitrogen. As the Mexican gas market goes, so goes the electricity market: Half of the country's generation capacity (68 GW) comes from combined cycle plants.

"If the USA no longer considers Mexico a free trade partner [under the North American Free Trade Agreement], then exports will require a public-interest review … and then an environmental review," Singer said. "Getting a permit to export gas to Mexico today is a very simple process. Representing the Mexican government, if we can't get that gas, it will really be problematic for the system. But it's also really problematic for Texas."

But Villarreal prefers a more optimistic outlook.

"I think the underlying assumption is that the gas trade between Mexico and the U.S. will continue to flourish," he said. "No investment on the gas infrastructure has been stopped. Nobody is saying, 'Oh, don't build that pipeline.' On the power side, we're working under the assumption that gas will not stop flowing from the U.S. into Mexico."

Overheard at the Infocast ERCOT Market Summit 2017

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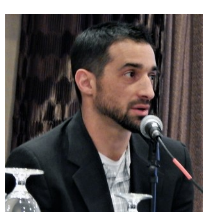
the TXU-Reliant legacy customers? I don't know."

Ancillary Services' Future in ERCOT

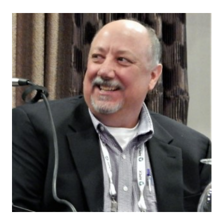
Austin Energy's commitment to participate in ERCOT's ancillary services market is a challenge because of the ISO's average prices, said Kahlil Shalabi, the municipality's vice president of energy market operations and resource planning.

"[ERCOT's] pricing is … much different than any other market," Shalabi said. "If you look at the past month here in Austin, the price dips down close to zero in the morning, then goes all the way up to $18 [per MWh] in the afternoon. If you're lucky, it goes up to $500 once a month for 15 minutes.

"We're not looking at future ancillary services pricing for future resource decisions," he said. "We do see price separation between our load zone and the rest of ERCOT. We want to use our generation to protect our customers when those price spikes happen."



"The robustness you see in Cal-ISO and PJM with advanced technologies and storage is due more to acceptance by those markets, rather than prices," said **John Fernandes**, who left RES for Invenergy after the summer as its director of regulatory affairs. "Those ISOs are setting up constructs that draw developers to those markets. When a system operator chooses to modernize the system to play to the strength of advanced technologies, that generates as much interest as price alone."



That is why Duke Energy Renewables' **Thomas Paff**, manager of RTO/ISO coordination, said his company is not yet buying storage in the ERCOT market.

"We do have some battery systems in PJM where it's totally different than the outlook here," he said. "We are making money, but it's really not that much."

— Tom Kleckner

ERCOT NEWS

Texas PUC Wary of Using ERS to Avoid Local Blackouts

By Tom Kleckner

"Whether it's paired with load or just on its own, [DG] needs to be integrated into ERCOT. ... I know ERCOT is working hard on that but I would strongly encourage them to make it a priority."

Ken Anderson, Texas PUC

The Public Utility Commission of Texas last week asked its staff to revise a rulemaking on emergency response service (ERS), saying it did not favor expanding the program to prevent local load-shed events (Project No. 45927).

As drafted, the proposed order would permit ERCOT to use ERS to prevent firm load shedding (rolling blackouts) in the event of local transmission emergencies. It also would give ERS resources the flexibility to replace reliability-must-run services.

ERS pays loads for reducing their consumption and distributed generation such as backup generators for injecting power during emergencies. ERS currently is used for non-local emergencies and is not permitted to also serve as a must-run alternative (MRA).

Commission staff published the rulemaking for comments in June 2016. The proposed amendments drew comments from 13 different groups, including ERCOT, its Independent Market Monitor and various energy companies and industry and environmental associations.

Price Suppression Concerns

PUC Chairman Donna Nelson said Thursday she "struggled" with the rulemaking and was concerned about ERS suppressing local prices when it is deployed to address local congestion. The draft order said the issue of price suppression should be addressed through the ERCOT stakeholder process.

Commissioner Ken Anderson said he shared Nelson's concerns, and asked staff to return to the amendment's original concept of allowing ERS participants to opt out of ERS "if they're in a situation in which ERCOT is seeking load alternative to RMR."

"If they're in an [MRA] contract, they can opt out at their choosing, but they forego the [ERS] payment," he said.

SCED Integration?

Anderson also asked staff to delete language in the preamble referencing a Shell Energy North America proposal to expand the current ERS program by allowing some resources to submit energy offer curves to ERCOT's security constrained economic dispatch (SCED) algorithm. As drafted, the proposed order says the commission agrees with ERCOT that requiring ERS resources to telemeter bids and respond to SCED dispatch would "undermine a core purpose of the ERS program — to capture the benefit of demand response or generation that otherwise would be unable to participate in the ERCOT market."

Anderson said the rulemaking had identified a bigger issue: the integration of distributed generation and allowing the resources to bid into SCED.

"Whether it's paired with load or just on its own, [DG] needs to be integrated into ERCOT," Anderson said. DG "should get the LMP. I know ERCOT is working on that, but I would strongly encourage them to make it a priority."

RMR Alternatives

Anderson told Monitor Beth Garza he thought one reason staff expanded the amendment's original scope was to address suggestions made by the Monitor that there might be other alternatives than the Greens Bayou Unit 5 RMR agreement. (See *ERCOT Ending Greens Bayou RMR May 29*.)

"It would be helpful if you could come up with a real concrete proposal that we could shoot at," he said.

Garza said her initial suggestion for using ERS resources in local emergencies was "not necessarily directed at RMRing Greens Bayou."

"Frankly, it was a response to ... other times we have had to shed load," she said, pointing to localized events. "I consider ERS as a program that allows loads to be paid, to be the first in line to be curtailed when we're at the cliff. At that point, the need for effective market mechanisms diminishes. Prices should be reflective of that. ERS is a way for specific loads to step up and say, 'Yes, I'll be the first ones to go.'"

Co-Optimizing

Anderson said that with a recent ERCOT cost-benefit analysis indicating a multi-interval SCED would not be cost effective, it opens up the discussion about co-optimizing the real-time market (shifting the responsibility for providing reserve services to online generation resources with the lowest incremental energy cost).

"Which we've been talking about for how long?" Nelson asked.

"I still had hair, I think," Anderson joked. "[Co-optimization] would help with the whole proper price signal and dispatching, hopefully minimizing reliability unit commitments. Then if we co-optimize, we could adopt local [operating reserve demand curves] that reflect that sort of scarcity."

Anderson was careful to say he was not expressing an opinion, but just hopeful of addressing congestion and local transmission problems.

"To the extent that you just eliminate unnecessary barriers, that's fine," he said. "I don't think ERCOT should spend a lot of time trying to use ERS to relieve localized problems."

"I would just leave the must-run alternative agreement aspect in the rule, and limit it to

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ERCOT NEWS

Texas PUC Wary of Using ERS to Avoid Local Blackouts

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that," Nelson said, saying she was concerned about interfering with ERCOT's competitive market. "The whole purpose of opening this rulemaking was to look at ways of using ERS as it currently exists and the money that's being spent. I do not in any way want to enlarge ERS … it shouldn't be larger than it is."

The draft order rejected calls to eliminate or increase the $50 million annual cap on ERS spending but promised the commission would review the limit if the new ERS local deployment product results in costs threatening to exceed the limit.

The commissioners asked staff to return with a rulemaking reflecting the day's discussion for the PUC's next open meeting March 30. Staff is targeting a March 23 publication of the revised language.

Commissioners Ken Anderson, Donna Nelson and Brandy Marty Marquez | © RTO Insider

The PUC also:

- Approved the City of Garland's request to amend its certificate of convenience and necessity with a final route for a double-circuit 345-kV transmission line east of Dallas that will interconnect ERCOT with the SERC Reliability Corp. through the proposed Southern Cross DC tie in Louisiana (Docket No. 45624). The line will connect an Oncor substation with a Garland substation, that will then connect with the Southern Cross.
- Approved a settlement between Entergy Texas and its customers allowing the utility to recover an annual revenue requirement of $29.5 million, almost $19 million above the amount approved in its previous transmission cost recovery (TCRF) factor proceeding (Docket No. 46357). Entergy will recover almost $3.4 million in additional transmission-related revenues through its base rates than it did when the TCRF baseline was set, because of an increase in billing determinants since its last base rate case.
- Reduced revenue requirements for Electric Transmission Texas by $46.2 million (Project No. 44550) and Cross Texas Transmission by $86.5 million (Project No. 45636). The reductions were a result of the PUC's annual true-up for regulated entities.

ERCOT Sees Adequate Capacity for Spring, Summer

ERCOT's latest seasonal assessment of resource adequacy (SARA) indicates ample generation for spring, with more than 82 GW of generation for an expected peak demand of 58 GW.

Nearly 1.5 GW of new gas-fired, wind and solar generation has become operational since the preliminary spring SARA was released in November.

A preliminary summer SARA anticipates a new record peak of nearly 72.9 GW, with 81.6 GW of capacity. That would break the mark of 71.1 GW set last year on Aug. 11. ERCOT said it expects another 2.5 GW of new gas-fired and 1.6 GW of wind and solar generation to come online before the June-September season begins.

ERCOT Senior Meteorologist Chris Coleman is predicting another hotter-than-normal summer in Texas this year. He said during a media conference call that the state is coming off what may be its warmest winter on record, and he does not expect any significant changes in the "warming trend."

"Eight or nine of the past summers have been hotter than normal," he told the ERCOT Board of Directors in January. "That's just been the trend. It would really be going out on a limb to forecast a mild summer for Texas this year."

A final summer SARA will be released in May.

— Tom Kleckner

ERCOT Ending Greens Bayou RMR May 29

ERCOT announced it is terminating its reliability-must-run agreement for NRG Texas Power's Greens Bayou Unit 5 in Houston, effective May 29.

The grid operator said studies using new criteria indicated the unit would not be needed for transmission system reliability after Exelon's 1,148-MW Colorado Bend II Generating Station in Wharton County, Texas, becomes operational in June.

The new criteria took effect with the passage of Nodal Protocol Revision Request 788 last fall. NPRR 788 requires a potential RMR unit to have "a meaningful impact on the expected transmission overload" to be considered for an agreement.

ERCOT said the previous rules, which used a forecast based on a 90% probability of exceedance, were overly conservative and that the new criteria should reduce the use of RMR contracts for reliability concerns that have a very low probability of occurring.

The RMR, ERCOT's first since 2011, was approved last June to run through June 2018. Greens Bayou 5 is the largest of seven units at NRG's Harris County complex. Built in 1973, the 371-MW natural gas unit was mothballed in 2010 and 2011, but returned afterward. (See "Greens Bayou Still Needed Under RMR Protocol Changes," *ERCOT Board of Directors Briefs*.)

— Rich Heidorn Jr.

ISO-NE NEWS

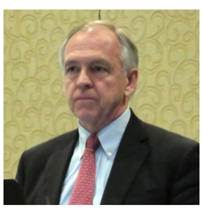
IMAPP Pondering 4 Options for Incorporating Clean Energy in NE Markets

Continued from page 1

will suspend its monthly meetings until May to allow ISO-NE time to develop "a conceptual market approach" that could be implemented in the near term for "accommodat[ing] state-supported capacity resources while appropriately pricing other resources in the Forward Capacity Market." The delay also will allow states time to analyze long-term proposals discussed to date and for them to hold "off-line" discussions with stakeholders. (See *NEPOOL Extends IMAPP Timeline*.)

"We at the moment are in a pause … because ISO-NE has said, 'We have to give you something to deal with the here-and-now that we're worried about," Doot explained. "They're going to come back with something for us to debate and digest in the May timeframe."

Infancy or Unruly Teens?



Panel moderator **David O'Connor**, senior vice president for energy and clean technology at ML Strategies, set up the panel by describing IMAPP as a "work in progress," adding that "by various metrics it could be described as yet being in its infancy."

But Doot characterized the initiative as being in "the unruly teen years."

"We're well beyond our infancy at this point. … We get into this room [and] there's a lot of people talking to each other, by each other, at each other — in varying levels of decibels depending on what exactly is going on."

Proactive

Doot said it was essential that New England stakeholders be proactive in developing a solution, noting that FERC has two cases pending before it challenging zero-emission credits for nuclear generators in NYISO and PJM.

"If we — NEPOOL or New England — don't do something, FERC is going to do it. They will do something to us or for us. And I can predict with some degree of certainty that we won't like it," Doot said.

"So I think what we need to do is decide whether we're going to take the opportunity in New England to establish how we want to change the marketplace in order to help the states achieve what they're trying to achieve in a way that allows the rest of the market to function, or whether we're going to have FERC tell us how they're going to do it. Because what we currently have is not necessarily sustainable in the long term."

Ron Gerwatowski, an energy and regulatory policy consultant, formerly with National Grid, agreed on the need to eliminate what he called the current "market schizophrenia."

"Somebody's going to take a meat ax to this if we don't fix it on our own," he said.

Four Proposals Explained

Doot said the proposed carbon adder would be included in energy offers and energy clearing prices and collected from carbon emitters under an allocation to be determined.

A second alternative, proposed by the Conservation Law Foundation, calls for a "Carbon-Integrated" Forward Capacity Market (FCM-C), under which a new ZEC market would be integrated with the FCM.

A third option, offered by RENEW Northeast and NextEra Energy, is a Forward Clean Energy Market (FCEM), a new forward market for new clean energy resources. As initially proposed, the FCEM would expand to include supports for existing renewable resources.

"We've been moving a little bit away from that in part because the price tag is so high," Doot said. "What they're now talking about is a capacity clean energy market just for new [resources] but that they would allow for support of existing resources through some form of carbon pricing."

The fourth proposal is a two-tiered pricing construct, with the FCM clearing at one price for existing resources and a lower price for state-supported resources offered at below competitive prices, an effort to protect prices from being suppressed.

'Civil War'

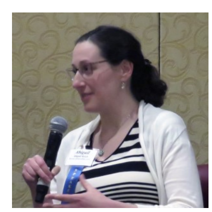
Gerwatowski said one challenge is that the states are not unified in their goals, referring to "somewhat of a civil war" between the northern and southern states.

"We have some uniformity among Connecticut, Rhode Island and Massachusetts … with respect to the very aggressive goals to reduce greenhouse gas emissions. We're in a very different place, I think, in New Hampshire and Maine — and in Vermont it's hard to read with the new administration coming in," Gerwatowski said, referring to Republican Gov. Phil Scott, who replaced Democrat Peter Shumlin in January.

"If you're in the southern states, anything that's going to drive greenhouse gas reduction, even if it comes at some costs, is going to be something that should be under consideration," he said, referring to carbon pricing and long-term contracts for renewables.

"They have a different perspective in the north. … They're not quite as convinced that these are the right ways to go in designing the future. We've heard some of the states, like New Hampshire in particular, saying, 'Look, you guys want to do something to raise prices in order to meet your goals, that's OK. But I'm not paying for it.'"

Capacity Market Limitations



Abigail Krich, president of Boreas Renewables, said that while New England's capacity market has provided price signals to encourage development of natural gas generators, it is insufficient for resources such as wind. Boreas worked on the FCEM proposal as a consultant to RENEW Northeast.

A combined cycle plant that wins a seven-year capacity contract at $7/kW-month can lock in almost 60% of its overnight capital costs, and a simple cycle turbine with the same contract would lock in 70% of its capital costs — both percentages high enough to secure financing, she said.

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ISO-NE NEWS

Overheard at NECA Renewable Energy Conference

AUBURNDALE, Mass. — About 200 people attended the snow-delayed Northeast Energy and Commerce Association Renewable Energy Conference on March 6. Here's some of what we heard at the conference, which was rescheduled after a February snowstorm forced cancellation of the original date.

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Offshore Wind

Offshore wind was a frequent topic in the opening session on emerging trends in renewables, which featured Matthew Morrissey, vice president of Massachusetts operations for Deepwater Wind.

The company, which began operating the nation's first ocean-based turbines off of Block Island, R.I., in December, won a contract from the Long Island Power Authority in January for a 90-MW wind farm off the island's Southern Fork. It also hopes to grab a piece of the big prizes to come: Massachusetts and New York have set goals for a combined 4 GW of offshore wind by 2030.

Unlike in Europe, which has a mature offshore industry, the U.S. does not have a fully developed supply chain for developers. Thus, Morrissey said, his company has been tapping the expertise and supply chains of offshore oil and gas drillers.

"There is a lot of commonality between the expertise and innovation that the United States has developed in that industry — putting large structures in the water — and we wanted to tap that both for our benefit but also because … we have to keep costs coming down, and in order to do that you have to have local, stateside … manufacturing," he said.

Morrissey and fellow panelist Richard Fioravanti, a principal with engineering and

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IMAPP Pondering 4 Options for Incorporating Clean Energy in NE Markets

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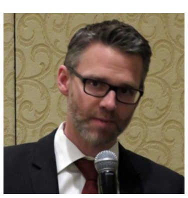
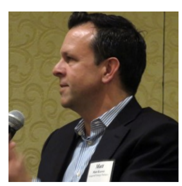
"A wind project, even if it's actually more cost effective overall when you look at energy, capacity, [renewable energy credits], things like that … they can only lock in about 6% of their capital costs," she said. "You can't take 6% of your capital costs as locked-in revenues and go get financing for a project based on that."

That, she said, is why long-term power purchase agreements are being sought for renewables. "We need these to be financeable projects," she said.



Jon Norman, vice president of government and regulatory affairs for Brookfield Renewable, said the current capacity market was designed primarily to support conventional fossil generation and doesn't address a growing gap in value recognition for existing sources of non-emitting generation, including hydropower and wind projects with expiring PPAs.

"At some point there needs to be a stable price signal" for existing clean resources, he said. "In the absence of that, you … end up over the long run cycling capital through and just putting it into new resources. And then old resources are either exporting somewhere else or they're retiring. I don't think that's a good outcome."



Matt Kearns, chief development officer for Longroad Energy Partners, said that states have generally found long-term contracts the cheapest way to meet their renewable portfolio standards.

"We've seen the most consumer savings generated by these larger procurements. … The result has been to attract cheap capital and drive down the cost of the product to the consumer," he said. "Sending a signal to the market for a 15-year contract, you tend to get very competitive, good results."

What Would FERC Do?

Doot said that he has been asked whether FERC has the authority to approve market rules that incorporate carbon policy. The commission has scheduled a technical conference for May 1-2 on the energy and capacity markets in PJM, NYISO and ISO-NE.

Before President Trump's election, Doot said, FERC was "begging us to come forward with something under our voluntary market structure that they can consider and potentially say yes to. Now, that was FERC before President Trump."

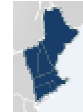
After Trump? "There's just no way of predicting," Doot said.

Doot ended the session by returning to a question about how consumer advocates can ensure that ratepayers don't "double pay" for carbon reductions through both an ISO-NE-wide carbon price and state initiatives such as renewable portfolio standards.

"The answer is 'Show up.' Because at the end of the day we have to come up with a solution. … If we don't come up with a solution, I'm not sure you have an assurance that you aren't double paying.

"It's up to us — the marketplace — to help define how it is we're going to address these challenges. If we don't, the federal government and the state governments are going to do it, and I'm not sure that the marketplace is going to be happy with the outcome."

ISO-NE NEWS



Overheard at NECA Renewable Energy Conference

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scientific consulting firm Exponent, said they were not overly concerned about the federal government reducing its role in energy research under the Trump administration.

"I see [renewable power] as a large, growing opportunity, and when there are opportunities, money follows," Fioravanti said.

"I would say that 10 years ago, a slowdown in research would have been a problem," Morrissey said. "But for the 10 or 15 or 20 years, the industry giants — like Siemens and General Electric and Vestas — [will be] driving innovation from a blade design point of view. And a lot of the foundation work they've done in the last 20 years — both in the U.S. oil and gas industry as well as the European offshore wind — with fixed bottom foundations, will drive the growth and cost curve downward … regardless of R&D coming out of Washington."

Morrissey said the offshore industry also can seek support in D.C. by touting its job creation potential.

"When you look at the kind of places with offshore wind-created economic opportunity, those places tend to look like post-industrial, urban forgotten cities like Fall River or New Bedford [Mass.] or other cities like that along the Atlantic seaboard, which actually tend demographically to look a lot like southern Ohio or western Pennsylvania [where Trump did well in the November election]. So we think that there is an underlay of opportunity to talk to the Trump administration about."

New England's Duck Curve

Michael Giaimo, senior external affairs representative for ISO-NE, used "duck curve" slides to demonstrate how growing solar photovoltaic penetration is affecting the RTO's ramps and system peaks. The RTO had 1.9 GW of behind-the-meter solar PV as of the end of 2016, more than two-thirds of it in Massachusetts.

While increasing PV boosts the need for ramping capability during the daylight, it does not affect the system peak in the winter, which typically occurs at about 7 p.m.

But PV generation could begin causing minimum generation emergencies in spring afternoons once PV generation reaches 3 GW, the slides showed. In the summer, increasing amounts of PV will push the net load peak later in the day, from 5 p.m. at current penetration, to 6 p.m. once penetration reaches 3 GW and 7 p.m. at 6 GW or higher.

"The low demand on a normal traditional day is like in the 3 a.m. timeframe," Giaimo explained. "When you start getting about 3,000 or 4,000 MW of solar, our new low demand for the day happens about 3 in the afternoon. We [are going] from a system that had a low at 3 a.m. to now a system that has a low at 3 p.m."

A Handful of States Writing the Rules on Community Solar

Eric Graber-Lopez, president of Blue-Wave Capital, talked about the delayed promise of community solar, noting that solar power adoptions still retain a "barbell" shape, with more than 90% of the market in residential rooftop panels or utility-scale facilities.

Legislative and regulatory debates, net

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metering capacity limits, program transitions and interconnection problems "have pushed back the promise of community solar," Graber-Lopez said. "The U.S. installed about half of what it expected to install in 2015, and it was expected to install about two-thirds [of earlier estimates] in 2016."

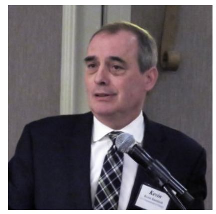
Community solar — which Graber-Lopez argues is a "proxy" for distributed generation in states such as Massachusetts — provides a way for renters, apartment dwellers and low-income housing residents to participate. "The problem is there's no such thing as a DG industry. It varies state by state," he said.

Massachusetts has been number two to California in DG deployment every year since 2014. Massachusetts, Colorado, Minnesota and New York account for 97% of the national pipeline for community solar over the next five to six years, he said.

"So there's a lot of talk about the deployment of DG — and by extension the deployment of community solar — but the fact is that there are four states that are setting the standard for how this industry is going to look going forward," he said.

Another 10 states are pursuing regulations or legislation "trying to either create, stop, modify or enhance DG," he said.

Ex-DOE Official Hopes Climate Progress is in Economy's 'DNA'



In a keynote speech, **Kevin Knobloch**, chief of staff for the U.S. Department of Energy between 2013 and 2017, said the Trump administration may not do as much to reverse Obama-era climate policies as some fear.

President Trump and EPA Administrator Scott Pruitt, who have expressed skepticism over humanity's role in global warming, are expected to attempt to cancel the Clean Power Plan. Trump also may withdraw the U.S. from the Paris Agreement on climate change.

But Knobloch, a former president of the Union of Concerned Scientists, said the renewable energy gains made during Obama's term won't be reversed.

"The Department of Energy's early and robust investment in clean energy and low-carbon technologies, with similar investments by industry and the research universities, coupled with forward-leaning and clear public policies, have contributed to dramatic cost reductions and increased deployment of clean energy and ultra-efficient technologies," Knobloch said. "And clean energy companies, like many of you represented here in this room, are consequently … well positioned to lead and compete in the rapidly emerging multi-trillion-dollar market for clean energy technologies."

He noted that 195 countries signed the Paris Agreement to reduce their carbon emissions. That's "195 markets for clean energy, renewable energy," he said.

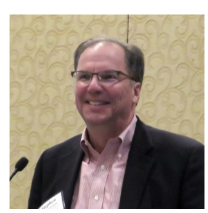
Knobloch said the dramatic budget cuts proposed by Trump to EPA and other domestic agencies to fund Defense Department increases would require undoing Congress' sequestration rules.

He also noted that Congress' last two major energy bills — the Energy Policy Act of 2005, which authorized loan guarantees for greenhouse gas control technologies and tax credits for alternative energy producers, and the 2007 Energy Independence and Security Act, which updated energy efficiency standards for appliances, residential boilers and other equipment — were approved with bipartisan support. He predicted Republicans such as Sen. Charles Grassley (R-Iowa) would fight any early termination of the wind production tax credit, which is due to be phased out over three years, ending after 2019.

"We also know that it is not so easy to reverse rules like the Clean Power Plan or the energy efficiency rules … with their extensive … rounds of formal public comment periods, prospects of legal challenge. These are all designed on the foundation of laws that were directed by the Congress.

"My hope is having achieved or made dramatic progress toward a lot of those goals, that renewable energy, energy efficiency … is now in the DNA of the economy," he said. "Those jobs are real. Those tax payments are real. The business plans and technology investments are all real and that that will carry on."

Lack of Tx in Multistate RFP Puzzles Developer



About 900 of New England's 1,300 MW of wind is in Maine. But the resources can't fully access the markets because of insufficient transmission. So **Stephen Conant**, senior vice president of Anbaric Transmission, said that he was mystified when officials running a clean energy solicitation for Connecticut,

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Overheard at NECA Renewable Energy Conference

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Rhode Island and Massachusetts included no transmission projects in their shortlist of projects last October.

Anbaric had proposed a project to unlock Maine's bottleneck and another project to deliver New York wind power and Canadian hydropower into Vermont. (See New England States Move Toward Renewables Contracts.)

"There's all kinds of theories out there," Conant said during a panel on the role of transmission and energy storage in integrating renewables, when asked to explain why his and other transmission projects were shut out. "We're all sort of scratching our heads."

Also in that session, **Dan Berwick**, general manager of the energy storage division at Borrego Solar Systems, said he was not dismayed by the limitations of current battery technology, which remains expensive for many large-scale, long-term storage applications.

"I'm pretty convinced we don't need a technological breakthrough right now — that the reductions in cost and the improvement in quality and performance that we're going to see through increasing repetitions and scale is capable of delivering a four- or five-fold decrease in … cost."

— Rich Heidorn Jr.

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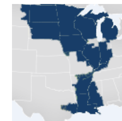
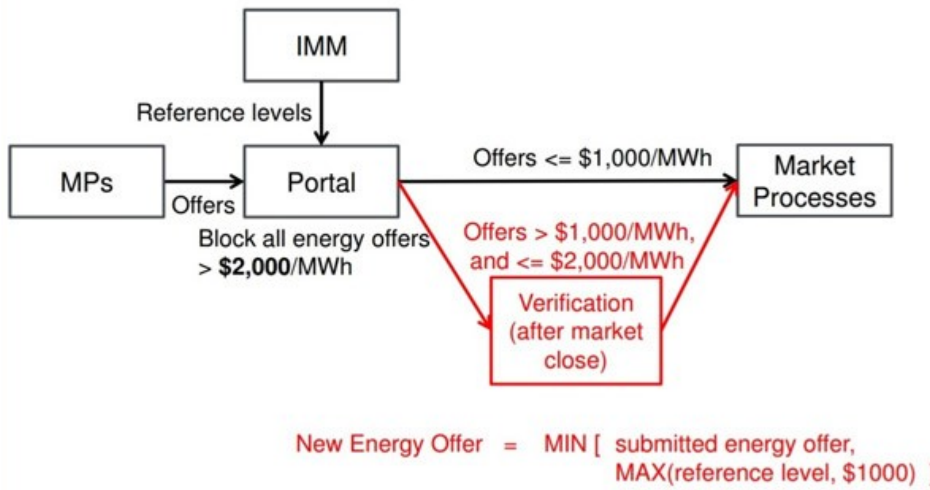
MISO NEWS



MISO Contemplates Market Design Changes from FERC Offer Cap Rule

By Amanda Durish Cook



MISO

CARMEL, Ind. — MISO is considering how to alter its market rules to comply with a FERC order that "softens" the current energy offer cap and establishes a higher "hard" cap for cost-based offers.

One potential change: The RTO could possibly increase its maximum value of lost load (VoLL), which represents the estimated amount that firm electricity customers would be willing to pay to avoid losing service. The VoLL, established in 2005, caps LMPs at $3,500/MWh. MISO is the only RTO to enforce such a cap.

"We really should update the value of lost load," Chuck Hansen, MISO senior market engineer, said during a March 9 Market Subcommittee meeting. "It's been around for a decade. It's probably time to refresh that number."

Hansen said MISO is hoping to implement FERC's directive by winter 2017/18, although the scope of the market changes could vary from adjusting the VoLL to ending LMP caps altogether.

Order 831 replaces the current energy offer cap of $1,000/MWh with a soft cap of $1,000 and a hard cap of $2,000 for verified cost-based incremental offers. MISO's offer portal will be reprogrammed to automatically block all offers above $2,000/MWh, while offers between $1,000 and $2,000/MWh will be verified only after the daily market close.

A resource may qualify for uplift payments if legitimate offers above $1,000/MWh cannot be verified quickly enough. For the past three winters, FERC has granted MISO a waiver on the RTO's energy offer cap policy. (See *MISO Granted Winter Waiver on Offer Cap*.)

"We have not seen offers above $1,000 yet in MISO," said Jeff Bladen, MISO executive director of market design. "The degree to which we could see them is just too hard to predict, [but] the likelihood that we see offers above $1,000 or $2,000 — [in] my view is it's pretty unlikely because we haven't seen it before."

Hansen said MISO's Independent Market Monitor will adapt to the new offer cap by stepping up its monitoring efforts next winter, updating resource reference levels as it keeps tabs on natural gas prices throughout the day. Going forward, market participants will be able to request a consultation with the Monitor for higher reference levels. The Monitor's Jason Fogarty said it would host a workshop later this year for market participants on the consultation process.

The Monitor's 2017 State of the Market report will likely recommend that MISO update the VoLL cap to also reflect the "likelihood of real-time capacity loss exceeding a given reserve level," Fogarty said.

According to Hansen, the higher energy offer cap paired with the operating reserve demand curve during scarcity conditions could easily breach the $3,500/MWh threshold.

Hansen said MISO could try to weather the higher energy cap with an updated VoLL cap and minimal Tariff changes — or undertake a major market redesign, in which the LMP cap would be abandoned in favor of a PJM-style system marginal price cap. MISO could also divorce its operating reserve demand curve from its VoLL cap, although it must be careful to keep LMPs in check, he said.

More involved market changes would "preclude a quick solution" — and MISO is hesitant to pursue a major market redesign, Hansen said. The RTO is asking market participants to submit suggestions on the issue by March 20.

MISO NEWS

Differences Persist over OMS-MISO Survey Improvements

By Amanda Durish Cook

CARMEL, Ind. — MISO will roll a 35% share of the capacity from resources sitting in the definitive planning phase of its interconnection queue into the annual resource adequacy survey conducted with the Organization of MISO States — over the objections of some stakeholders who seek inclusion of a greater portion of capacity.

The survey currently counts only future resources that have already executed a generator interconnection agreement.

Indianapolis Power and Light's Lin Franks said MISO's 35% completion estimate is too conservative, especially when considering projects submitted by state-jurisdictional utilities that are obligated to serve load and whose projects might be more reliably completed than other queue entrants. (See *Stakeholders, MISO at Odds over Resource Adequacy Survey*.)

"You know the damn thing is going to be built — it needs to be included" in the survey, Franks said during a March 8 Resource Adequacy Subcommittee meeting.

She also warned of the "self-feeding" problem of developers entering the queue long before they are certain that a resource will be constructed — the product of long queues.

Franks suggested that MISO examine rates of withdrawal based on resource type.

"If you don't take a look at which resources are withdrawing, you don't have a transparent picture," she said. "You've got to be more transparent and not convince people that the sky is falling."

Madison Gas and Electric's Gary Mathis said he did not see evidence of stakeholder advice in MISO's proposed improvements.

"This issue has been around for a number of years, and MISO has been aware for a while of the improvements that are needed. … Certain projects in the queue will be realized," he said. "I'm disappointed that we didn't come further, and I question whether we were listened to in this process."

The RTO says it will consider adding more resources in other phases of the queue as it carries out queue reforms.

Darrin Landstrom, MISO's resource forecasting adviser, said the terms "committed" and "potential" will replace the "high certainty" and "low certainty" descriptors currently used for resources in the queue's definitive planning phase.

Bonnie Janssen, a Michigan Public Service Commission staffer, said OMS could additionally include a "probable" category. MISO will send out questionnaires by March 31, with detailed results expected to be released in June.

Laura Rauch, manager of resource adequacy coordination, said MISO can provide stakeholders with mockups of survey results at the April RASC meeting.

RASC Chair Chris Plante plans to present MISO and stakeholder differences over the survey's improvements to the Board of Directors during its March 23 meeting.

Resource Adequacy Subcommittee Briefs

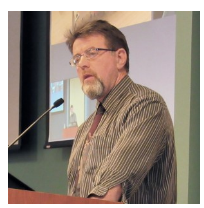
Preliminary PRA Data Show Capacity Excess

CARMEL, Ind. — Recent preliminary load forecast data for the 2017/18 Planning Resource Auction show that each of MISO's local resource zones has enough capacity on hand to meet its own clearing requirement.

The RTO's 172 GW worth of total installed capacity can handily meet its 135 GW of planning reserve margin requirements, John Harmon, MISO manager of resource adequacy, said during a March 8 meeting of the Resource Adequacy Subcommittee.

A general slowdown in manufacturing and continued energy efficiency efforts across the footprint is slowing load growth and lowering peak forecasts, Harmon said.

MISO derives its load estimates from a random sampling of load-serving entities and data reviews from LSEs whose load represents 45% of the RTO's annual peak demand, according to Michael Robinson, MISO's principal adviser of market design.



Robinson

Robinson said MISO this year encountered issues with LSEs not providing historical data, excluding methodologies for non-coincident peak and accounting for transmission losses, which the RTO already does once it receives the data. He said all LSEs eventually met the forecast reporting requirements.

"We did see a rash of LSEs that didn't provide all the information originally," Robinson said, suggesting the "tightening" of some documentation requirements.

Multiple stakeholders expressed concern that MISO still has 7,300 MW of unconfirmed unforced capacity a month before the auction and asked about the potential for moving up registration deadlines to get more complete data earlier — something Harmon said the RTO would consider.

Harmon said that the unforced capacity data includes about 15 generators that have applied to defer completion of their generator verification tests — which qualify resources as capacity resources or load-modifying resources — until after the 2017/18 PRA.

MISO said that it will separately report reserve margin data from Michigan's Local Resource Zone 7, after receiving permission from market participants there that were concerned about protecting competitive information.

Zone 7 shows a 20-GW coincident peak load and a 22-GW planning reserve margin.

Zones 3, 5 and 7 were previously grouped together, as were zones in MISO South (Arkansas's Zone 8, Zone 9 covering Louisiana and Texas, and Mississippi's Zone 10). Iowa's Zone 3 and Missouri's Zone 5 will continue to be grouped together. (See "Preliminary Load Forecast Released," *MISO Resource Adequacy Subcommittee Briefs*.)

MISO will host a stakeholder call to review

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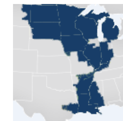
MISO NEWS



MISO to Fix Recently Discovered Tariff Mistake

By Amanda Durish Cook

CARMEL, Ind. — MISO will file with FERC to correct a recently uncovered eight-year-old Tariff mistake related to the RTO's day-ahead margin assurance payment.

The RTO has found that Module C of its Tariff contains language saying that any resource that incurs an excessive or deficient energy deployment charge during one hour will be "ineligible for [day-ahead margin assurance payment] in that hour and all remaining hours in the day-ahead transmission provider commitment period."

The problem: MISO prohibits the receipt of the day-ahead margin assurance payment only for the hour in which the resource incurred the charge; it does not observe an hours-long disqualification. The Business Practice Manuals limit payment ineligibility to the single hour the charge was incurred. A longer disqualification would restrict dispatch flexibility, the RTO said.

Despite the discrepancy between the Tariff and manuals, settlements have reflected guidelines in the latter since the beginning of MISO's ancillary services market in 2009, said Jeff Bladen, executive director of market design. The erroneous language does not represent current or historical practice, Bladen said, and the error is not repeated in BPM language or MISO training manuals.

"The practice described in the Tariff was neither the intended method nor has it ever been used by MISO before or since 2009," Bladen said at a March 9 Market Subcommittee meeting.

MISO will submit a Section 205 filing with FERC to remove the Tariff language and payment eligibility will carry on as usual, Bladen said.

"MISO immediately reported the issue to the FERC Office of Enforcement," Bladen said. The error was uncovered during "unrelated" Tariff research.

Bladen said neither MISO nor its Market Monitor support resettlements, and no gaming was discovered.

David Sapper of Customized Energy Solutions asked what efforts the RTO could make in the future to catch Tariff errors.

"We are regularly undertaking compliance reviews. … We are subject to FERC compliance reviews," Bladen said. "The level of obscurity of this Tariff language is evidenced by the fact that this wasn't uncovered during those reviews."

Resource Adequacy Subcommittee Briefs

Continued from page 23

the results of the PRA on April 14, followed by a longer meeting on the subject April 17.

In a related matter, the deadline to seek rehearing on FERC's order prohibiting MISO's three-year forward auction design has passed without any parties requesting a rehearing. (See *MISO Won't Seek Rehearing on Auction Redesign*.)

"MISO still believes that mechanisms are needed to support competitive retail areas," RASC liaison Shawn McFarlane said. He added that the RTO will work with Illinois officials to develop separate capacity auction provisions for retail areas that will not affect regulated areas.

The RTO is also awaiting FERC's decision on whether it can apply a more stringent physical withholding rule and remove some resources from market monitoring in next month's PRA (ER17-806). (See *MISO Plans Additional Capacity Auction Revamps for 2017*.)

MISO attorney Jacob Krause said the RTO could implement the changes — subject to refund — prior to the auction, or that FERC could issue a deficiency letter delaying the changes until the 2018/19 PRA. The commission has until March 17 to act on the filing.

IMM Offers Own PRA External Zone Design

The Independent Market Monitor is recommending its own option for the proposed locational element to the PRA — a year after the RTO began discussing the matter.

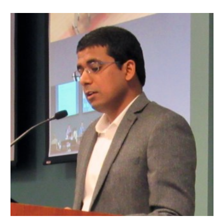
Monitor David Patton wants MISO to create external resource zones based on neighboring balancing authority boundaries and set a clearing price for each external zone set using a shadow price and shift factor. By comparison, MISO staff have proposed six smaller, external resource zones based on geographic groupings of generation and transmission that would be priced using sub-regional prices and clear in the PRA.

Patton's suggestion would require MISO to quantify how much capacity would be delivered from SPP and PJM and model how the power would flow through MISO's internal zones. He said his approach would create consistency for MISO operations even as PJM and SPP resources supply capacity.

Some stakeholders asked why an LSE would purchase from external suppliers when the price would be different from auction clearing prices.

Patton said he didn't see a difference between an LSE contracting bilaterally to purchase power from a different MISO zone and buying megawatts from an external resource. He said he would return to the RASC next month with a more detailed proposal.

Indianapolis Power and Light's Ted Leffler said buying externally for commercial purposes — and not for reliability — represents an "imperfect hedge."


Korad

However, MISO staff have proposed that external zones clear the PRA at a systemwide or sub-regional clearing price — and not at their offer prices. Akshay Korad of MISO's market design and evaluation team said the RTO's three simultaneous feasibility tests run after the

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auction could limit the capacity export limit of external resource zones if constraints bind and price the external zones as a marginal resource.

MISO used its four proposed MISO Midwest (formerly MISO North) external zones and two proposed MISO South external zones to run a simulation of the 2016/17 PRA. Using the projected external zones, MISO concluded that zones 2-7 could have cleared at \$24.80/MW-day, instead of the actual \$72/MW-day. (See *MISO's 4th Capacity Auction Results in Disparity*.)

A small number of megawatts in the 2016/17 PRA caused the capacity export limit to bind, dictating the high clearing price in zones 2-7, Korad said.

"Even if you see that supply stack change a little bit, you're going to see a change in price," Korad said.

The six resource zones proposed by MISO are based on external zones that cleared in the most recent auction, and the number and location of external resource zones could change, said Laura Rauch, MISO manager of resource adequacy coordination.

Stakeholders asked MISO staff to come back with more pricing simulations using external zones.

Like other stakeholders, Leffler remained critical of the entire external zone concept. He asked why MISO couldn't require LSEs to create fixed resource adequacy plans to hit their full local clearing requirements using only local resources and forbid them from relying on external resources toward their local clearing requirement.

"There ought to be a way that's easier to do this than create external resource zones," he said.

MISO Examines Single Year of MISO-SPP Settlement Allocation

MISO stakeholders are questioning the benefits of debating whether some costs of MISO and SPP's transmission use settlement be allocated to holders of transmission service requests above the 1,000-MW contract path. MISO wants to determine who gets allocated the costs for using the North-South interface for about 300 MW that went above the 1,000-MW North-South limit in 2018/19.

Stakeholders will decide if the RTO can allocate a portion of the costs of just one year of the settlement — the 2018/19 planning year — based on capacity benefits, where firm TSRs from MISO South to MISO Midwest reach 1,304 MW. In all other years of the settlement from 2014-2021, TSRs were or are 1,000 MW or below.

MISO's Jesse Moser said the question is "narrowly focused" on capacity benefits and is not a forum for negotiating other terms of the settlement agreement.

"MISO is approaching this without a desired outcome in mind. We're facilitating discussion," Moser said.

Multiple stakeholders said that an effort to decide the one-year allocation within MISO's stakeholder process might not be worth pursuing considering the low monetary amount at stake.

Per the settlement agreement, MISO has until Nov. 17 to decide on an allocation to TSR holders, either by filing to alter the terms of cost allocation or making an informational filing to explain that it won't change allocation.

"That 1,000-MW cap should have been in place in OASIS prior to December 2013," NRG Energy's Tia Elliott observed dryly.

Mathis wanted to know the dollar amount at stake — something Moser said he could supply at the April RASC meeting.

The settlement dictates that costs be allocated on a graduating scale based on a ratio that phases out over time — with 100% to load in the first two years of the settlement, decreasing to 45% in the third year and 10% in the seventh year, with the remaining percentage taken on by a flow-based allocation.

MISO pays about \$27 million per year for use of SPP's transmission that links the RTO's Midwest and South region. The maximum amount MISO could pay under the settlement for heavy transmission use is \$38 million per year.

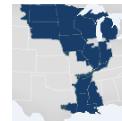
MISO Wants Deferral Year to Create Queue Withdrawal Penalty

MISO is seeking a yearlong extension to develop specific penalties for generation project withdrawal, as directed by FERC in the RTO's interconnection queue overhaul (ER17-156).

MISO attorney Jacob Krause said the RTO wants to hold off on a filing until March 31, in order to work with stakeholders to determine an appropriate penalty. He said MISO is currently seeking FERC permission for the deferral.

— Amanda Durish Cook

MISO News



Market Subcommittee Briefs

Two Alterations to Emergency Pricing

CARMEL, Ind. — MISO will make two changes to improve its year-old emergency pricing structure by this summer in addition to the two emergency pricing floors rolled out last year, RTO staff said during a March 9 Market Subcommittee meeting.


Akinbode

The first change: Commitment costs of offline fast-start units will be allocated into the minimum runtime when calculating the offer floor for emergency prices.

The second: Emergency-committed units dispatched at their economic minimum prices will be allowed to set those emergency prices.

The two changes were the only selected among the five proposed by MISO staff after a July 2016 emergency event resulted in depressed prices. (See "MISO May Tweak Emergency Pricing Floors," *MISO Market Subcommittee Briefs*.)

MISO engineer Oluwaseyi Akinbode said the modifications are meant to produce more efficient prices.

"If you believe what the planners are saying, there's a chance we will get into these emergency conditions this summer, and we want to be prepared for that," Akinbode said.

New User Group Aims to Improve Ease-of-Use in MISO Apps

MISO will later this month debut a new Application User Group for people who use the RTO's technology.

April Peterson, a representative from MISO's asset registration team, said the group will focus on improvements and common challenges market participants face when using the RTO's computer market applications. She said attendance is also open to MISO software vendors and IT specialists that are contracted to make software changes.

Peterson said MISO aims to hold conference calls monthly, with the first call scheduled for March 23.

Potential Cost Recovery Gap in Manual Redispatch

Day-ahead resources can see gaps in cost recovery when they are manually redispatched offline — and a Tariff change could remedy the problem, MISO staff said.

When the RTO decommits a day-ahead resource, the day-ahead margin assurance payment does not take into account the resource's minimum down times or start-up costs for reimbursement, said Jason Howard, MISO market quality manager.

Howard said yet-to-be-written Tariff language could "close the gap."

"The manual redispatch might only last four hours, but a minimum down time for a resource might be seven hours," Howard explained. "Our current day-ahead margin assurance payment does not account for these situations."

Proposed Tariff language will be presented at a future Market Subcommittee meeting.

— Amanda Durish Cook

MISO NEWS

MISO, PJM Propose Rebates to Solve Double-Counting of Pseudo-Tie Congestion

By Amanda Durish Cook

MISO and PJM staff broke their silence on ongoing efforts to solve the RTOs' pseudo-tie congestion double-counting problem.

At a Feb. 28 MISO-PJM Joint and Common Market Initiative meeting, Kevin Vannoy, MISO director of forward operations planning, said the RTOs would solve the double counting of congestion for pseudo-tied resources in the near term by providing congestion rebates, while they would develop a way to allow pseudo-ties in the day-ahead scheduling process by 2018.

The fix may also be applied to pseudo-ties between MISO and SPP.

"MISO now has over 5,000 MW of pseudo-ties in and out [to PJM and SPP] that could be subjected to this congestion overlap," Vannoy said.

MISO and PJM said they hope to roll out the first phase of the changes by June 1. They will include accounting for market flows in market-to-market settlements so attaining balancing authorities have enough revenue to issue refunds. The congestion overlap will be addressed by allowing attaining BAs to provide congestion rebates for generators.

Beginning in June 2018, the RTOs plan to have Tariff and joint operating agreement changes in place that let pseudo-ties schedule and settle in the source BA's day-ahead market. The day-ahead coordination will take significantly more work than the near-term rebate plan.

"Right now, the day-ahead markets in MISO and PJM might not be aligned," Vannoy said, adding that each RTO is only aware of the other's constraints in real time.

MISO and PJM officials acknowledged that creating a rebate process by June 1 is ambitious. "This is a very aggressive timeline. For something to be in place by June, we have to work on Tariffs and JOAs," Vannoy said.

Both MISO and PJM staff said they could convene a special meeting to discuss the proposal before the next scheduled Joint and Common Market meetup in May.

Due Date	Who	Action
~~March 1, 2017~~	~~MISO, PJM~~	~~Develop Short-Term and Long-Term solution to Congestion Overlap~~
April 1, 2017	MISO, PJM, Stakeholders	MISO and PJM complete work with stakeholders, including Complainants on Solutions to Congestion Overlap and Double Charge. File Tariff and JOA changes with FERC as appropriate.
May 1, 2017	MISO, PJM	Deliver changes to JOA and Settlement Systems with a target implementation of June 1, 2017
June 1, 2017	MISO, PJM	Implement Short Term Solutions
June 2017 – May 2018	MISO, PJM	Deliver and implement Long Term Solutions
June 2017 – May 2018	MISO, SPP	Deliver Short and Long Term Solutions

Timeline of possible next steps | *MISO, PJM*

SPP Also?

The process could also be applied to MISO and SPP's pseudo-tied generation and load. Unlike MISO and SPP, MISO and PJM don't share any pseudo-tied load; all pseudo-ties are generation-based. Vannoy said the proposed rules could apply to MISO and SPP's pseudo-tied generation and load "to the extent that we can get to a solution."

Solution to FERC Complaints

Vannoy said MISO and PJM will also discuss the proposed solutions with two municipal power agencies and a generator that have filed complaints with FERC over the double counting to "explore resolution outside FERC."

In November, both RTOs declined to publicly discuss the double-counting issue until the complaints were resolved. (See *PJM, MISO Go Quiet on Pseudo-Ties; Reach Interface Pricing Accord*.)

Tilton Energy, the owner of a 180-MW natural gas generator in Eastern Illinois, filed a complaint in August arguing that MISO is violating its Tariff by assessing congestion and scheduling fees on Tilton's pseudo-tied transactions that have already been assessed by PJM (EL16-108).

In a late December complaint, the Northern Illinois Municipal Power Agency asked for a "full evidentiary proceeding involving PJM, MISO and the numerous pseudo-tying entities being harmed by the implementation of MISO-PJM pseudo-ties" (EL17-31).

And in January, American Municipal Power asked FERC to stop PJM from collecting charges from generators pseudo-tied out of the MISO balancing authority area where congestion charges were already assessed (EL17-37).

MISO Assistant General Counsel Michael Kessler has said FERC might combine the complaints.

Asked whether the RTOs would share with stakeholders details of their discussions with the plaintiffs, MISO Managing Assistant General Counsel Erin Murphy said the current meeting's discussion might solve the complaints.

"I can't say that there won't be separate discussions," she added.

Generator Skeptical

Tilton representative Elena deLaunay asked why PJM would be the appropriate side of the double count to be refunded, saying that MISO's congestion charges were more inappropriate for PJM-based Tilton. She asked why PJM should have to provide refunds when its congestion is in the market the generator is being settled in, is created through the market-to-market process and flows through the make-whole calculation.

"We are being dispatched into price signals on the MISO side that we can't follow as a PJM resource," deLaunay said.

She also said the long-term solution to solve congestion double counting may be flawed: "Forcing us to speculate on which market we will be dispatched in [day-ahead or real-time] can create additional risk rather than mitigating it."

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NYISO NEWS

NY Lawmakers Frustrated by Lack of Answers at ZEC Hearing

By Michael Kuser

ALBANY, N.Y. — A New York State Assembly hearing March 6 to explore the Cuomo administration's subsidies for upstate nuclear plants left lawmakers frustrated as the Public Service Commission and the New York State Energy Research and Development Authority declined to attend and Exelon sent no senior executive with knowledge of the subsidy negotiations.

"I'm disappointed that they chose not to attend," said Assemblyman Jeffrey Dinowitz (D-Bronx), the head of the Committee on Corporations, Authorities and Commissions, who chaired the meeting. "It's important to hear from PSC and the executive branch."

Exelon, owner of all the nuclear plants set to receive the zero-emissions credits, sent five witnesses, most of them engineers, with the highest rank being a plant vice president. "Maybe you can take notes and send your answers later," Dinowitz told them sarcastically.

Exelon also submitted testimony from Joe Dominguez, executive vice president of governmental and regulatory affairs and public policy, who said the company would spend $700 million on the plants because of the financial assurance provided by the ZECs. The ZECs would benefit Exelon's R.E. Ginna, and Nine Mile Units 1 and 2 generators — and the James A. FitzPatrick plant it is purchasing from Entergy — for more than 12 years.

'Staggering Increase' in Pollution

"The closure of these plants would have resulted in a staggering increase in air pollution throughout New York because the electricity void created by the closures would have been filled by coal, oil and gas plants operating in and around New York," Dominguez said.

The PSC said it was unable to attend because of scheduling problems.

"Unlike the 24 public hearings that the Public Service Commission held across the state in developing the Clean Energy Standard [CES], which were scheduled many weeks in advance, the Assembly only informed us of this hearing late last week, and so we were unable to attend due to scheduling conflicts," PSC spokesman James Denn said in a statement. The Assembly issued the public notice for the hearing on Monday, Feb. 27.

Instead, the state agencies submitted written testimony from PSC Chair Audrey Zibelman, NYSERDA CEO John Rhodes and Richard Kauffman, Cuomo's top energy adviser. The statement defended ZECs, part of the CES, which also requires that the state generate 50% of its electricity from renewable resources by 2030.

"Fossil fuel generators and anti-nuclear activists have attempted to mischaracterize the Clean Energy Standard as a bailout or a tax," they wrote. "But … it is unquestionable that the Clean Energy Standard benefits all New Yorkers across the state and, moreover, charts the most responsible path forward on combating climate change and growing our clean energy economy. … Simply put, without the ZEC program, New Yorkers would pay more for dirtier power."

$7.6 Billion Cost

Several New York City-area legislators have questioned the wisdom and process of last August's decision by the PSC to approve the CES and ZECs.

The program distributes costs statewide; in its first two years, all New York energy consumers will pay an additional $965 million to keep the nuclear plants running. The costs may rise by as much as 10% in each successive two-year tranche, for a potential total of $7.6 billion.

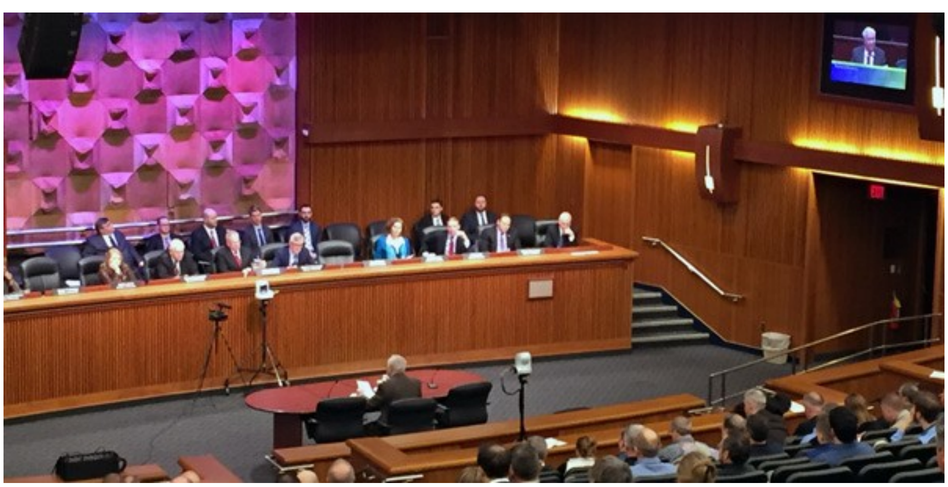
Dinowitz chaired the hearing in place of Energy Committee Chairwoman Amy Paulin, who was unable to attend. The other committees participating in the hearing were Environmental Conservation, chaired by Assemblyman Steve Englebright (D-Setauket), and Consumer Affairs and Protection, chaired by Assemblyman Brian Kavanagh (D-Manhattan).

Englebright said that he remembered when nuclear power was being touted as being "too cheap to meter, which doesn't seem to be the case today." Kavanagh said he was concerned whether the ZEC charges are fairly imposed and in a transparent manner.

Subsidies Too Generous to One Company?

Blair Horner, director of the New York Public Interest Research Group (NYPIRG), testified first and focused on "a public information gap, which seems like a deliberate strategy. A year ago, we were talking about a $100 million bailout of the upstate plants. Then, as soon as the Assembly went into recess, a significantly more expensive program appears. Is this democracy? It's no surprise the executive branch chooses not to testify."

Horner said that the state already has



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NY Lawmakers Frustrated by Lack of Answers at ZEC Hearing

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800,000 electricity users who are 60 days or more in arrears on their electric bills and that the CES-related rate hikes would be a hardship for them. The Cuomo administration says the CES, including the ZECs, will add less than $2/month to the average residential customer's bill.

Exelon expects the New York ZECs and a similar program in Illinois will add 17 cents/share to its 2017 earnings, 6% of its total profits, according to Crain's Chicago Business.

"We view the CES charges as a tax being imposed by the wrong branch of government," said Horner. "Even if you disagree with our view, at least the process should be changed to create a meaningful public process. It's your duty as a co-equal branch of government. The beneficiary of this program is one company, and $7.6 billion seems overly generous to me. Hit the pause button."

Assemblyman Will Barclay (R-Pulaski) responded that NYPIRG "seems more anti-nuke than pro-public. There were no complaints about zero-emissions credits for renewables."

Legislature Should Set Energy Policy

Former Assemblyman Richard Brodsky, a longtime opponent of the Indian Point nuclear plant, testified as a private citizen and reminded lawmakers that the PSC was indeed "a legislative agency, not an offshoot of the executive."

Brodsky urged the Assembly to reconsider the decision to spend an estimated $303,000 per job per year in subsidizing "decrepit" nuclear facilities. "They're fixer-uppers, and it costs more to do that than to live in a new house," he said.

The social cost of carbon used by federal agencies to value the climate impacts of rulemakings — and used to set New York's ZEC values — was not meant as a policy-making tool and has massive limitations, Brodsky said. "I didn't know the Constitution had a pause button — it's time for the legislature to set energy policy. The ISO's market clearing price is the most idiotic policy ever."

Not 'Decrepit'

Exelon sent five witnesses to the hearing: Joseph Pacher, site vice president at the Ginna plant; James Vaughn, senior engineering manager at Nine Mile Point; Adam E. King, radiation protection supervisor at FitzPatrick; John Scalzo, engineer; and James Melville, senior radiation safety operator at FitzPatrick.

John Scalzo, engineer; Adam E. King, radiation protection supervisor at FitzPatrick; James Vaughn, senior engineering manager at Nine Mile; Joseph Pacher, site vice president at the Ginna plant; and James Melville, senior radiation safety operator at FitzPatrick. | © RTO Insider

Pacher said that, far from being decrepit, "all three stations are performing better than when new," citing their capacity factors of more than 90%. "Preserving nuclear plants upstate is good sense. These plants could be run safely for decades."

Dinowitz asked about the costs of operating each plant, but none of the witnesses could answer. Vaughn said that the "$7.6 billion is an estimate, and keep in mind that without natural gas prices so depressed, we wouldn't need any subsidy at all. It's not to line our pockets but to keep the plants profitable. The ZEC program establishes a floor price, so if gas prices go up we'll take less in subsidies."

Englebright said, "ZEC is supposed to be a transition program, not preserve the status quo. When did Exelon first think they would need a subsidy?"

2015, Pacher replied, which was when the company began negotiating a reliability support services agreement at Ginna, which FERC approved in March 2016.

Kavanagh asked if the upstate plants were safer than Indian Point, which is slated to close by 2022 under an agreement between the Cuomo administration and plant owner Entergy. Cuomo has long sought the plant's closure because of its proximity to New York City. (See related story, *NYISO, PSC: No Worries on Replacing Indian Point Capacity*, p.30.)

"We don't operate Indian Point, so I don't want to say," Pacher responded. "There's public perception of aging, decrepit nuclear plants upstate, but people who take tours are always impressed with our facilities."

Kavanagh asked if the Ginna reactor wasn't the same design as that at the Fukushima Daiichi plant in Japan, which failed when it was flooded by a tsunami in March 2011. Pacher admitted the similar designs but said it was the Japanese plant's location on the Pacific Ocean that was its biggest vulnerability. "The worst thing for Fukushima was its location, but examining their experience did lead us to re-evaluate our event amelioration strategies," he said.

Exelon says its nuclear plants, with a total capacity of 3,350 MW, employ 2,600 full-time workers and pay more than $45 million in annual property taxes and $144 million in "direct and secondary state tax revenues."

Court Challenge

The PSC in December rejected 17 petitions to reconsider its CES decision, though it agreed to investigate a few instances concerning "eligibility issues" for some resources. (See *NYPSC Rejects Challenge to Clean Energy Standard, Nuke Subsidy*.)

In a separate action, a group of energy companies and trade groups in October filed a suit in U.S. District Court for the Southern District of New York, claiming the ZECs intrude on FERC's jurisdiction over interstate electricity transactions. The suit asks the court to find the ZECs invalid and order the PSC to withdraw them from the CES.

NYISO NEWS

NYISO, PSC: No Worries on Replacing Indian Point Capacity

By Michael Kuser and Rich Heidorn Jr.

NYISO CEO Brad Jones and Public Service Commission Chair Audrey Zibelman told New York legislators they are not concerned about replacing the capacity of the 2,069-MW Indian Point nuclear plant, saying energy efficiency, transmission upgrades and the ISO's wholesale market will ensure reliability.

Jones said that the grid operator has many options and "plenty of time" to resolve any reliability issues arising from closing the plant. In an aside, he also said the ISO is considering requiring new gas-fired generation to have dual-fuel capability.

NYISO has yet to receive a formal notice of deactivation of Indian Point, which would trigger a 90-day assessment period, but Jones told legislators during an eight-hour hearing Feb. 28 that he expects one will be filed in the coming months.

NYPSC Chair Audrey Zibelman and Richard Kauffman, chairman of Energy and Finance for New York testify before the joint committee. | *New York State Committee on Energy & Telecommunications*

Joint Hearing

The State Assembly's Committee on Energy held a joint hearing with the State Senate's Committee on Energy and Telecommunications on the plant, located on the Hudson River 30 miles north of New York City. Plant owner Entergy and Gov. Andrew Cuomo announced an agreement in January to shut down Unit 2 in 2020 and Unit 3 in 2021. Unit 1 ceased operations in 1974. (See *Entergy to Shut Down Indian Point by 2021*.)

Assembly committee Chair Amy Paulin (D) asked how the ISO evaluates the reliability effect of a facility going offline. Jones said that several factors influence the assessment process, mainly the fast-changing power system itself.

"Literally, the system is changing as much as it ever has in the past," Jones said. "For example, we have new transmission, some that is under construction, as well as transmission that is in the process."

Jones cited proposed upgrades to relieve congestion in Western New York and the AC Transmission initiative to increase the Upstate New York/Southeast New York transfer capacity by 1,000 MW. (See *NYPSC Staff Recommends $1.2B in Transmission Projects*.)

He also noted increased energy efficiency and production from rooftop solar panels as well as "load shifting" by some market participants.

Senate Committee Chair Joseph A. Griffo (R) asked Jones whether the state's goal of having renewables provide 50% of its electricity by 2030 was realistic. Jones said the goal was "ambitious, but achievable."

Dual-fuel Requirement Coming?

Paulin asked the CEO to pinpoint the possible outcomes of a reliability assessment on Indian Point's closure. Jones said that in the event of a reliability concern, the ISO would first approach the market to find solutions. If the market failed to find a solution, the next step would be to look for a regulatory fix.

"Now, one of the options for the replacement of Indian Point would be to have additional gas units that come online to replace that," Jones said. "There are a variety of different scenarios that I think are feasible. If the replacement generation does come from natural gas, we have been concerned at the NYISO, as we rely more upon natural gas, about the reliability of the supply of the gas itself. And so we've begun to look at … whether we should and could require generators throughout New York to have a dual-fuel supply."

Planning Since 2011

Zibelman said the state has been planning for Indian Point's closure since at least 2011, citing the AC Transmission project, which should begin construction in 2019 and be operational by summer 2022. She said new or mothballed generators will enter the ISO market if needed.

"New York has had a really good history of power plants getting built in response to market" demand, she said, citing the 6,000 MW of new plants added since the NYISO markets began.

"I'm not concerned about the replacement power. We have a robust market. There's a lot of capital. People are very interested" in building new plants, she continued. "That plus the work we're doing on energy efficiency and demand response and the transmission — all of those in combination is what makes me extremely comfortable that we're not going to have a scarcity issue."

She noted that New York's wholesale power prices declined by 25% between 2012 and 2016, thanks largely to cheap natural gas. Over the same period, energy efficiency has caused the ISO to reduce its 2021 peak load forecast by almost 7% to 33,555 MW. Thus, she said, the plant's closure should have a "negligible or no adverse" impact on

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NYISO NEWS

NYPSC Adopts 'Value Stack' Rate Structure for DER

Continued from page 1

over time to increase the granularity and accuracy of the valuation.

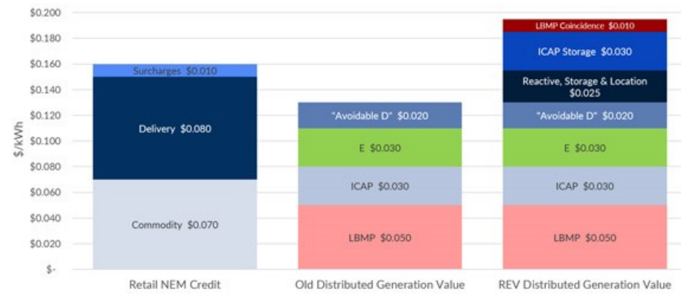
"This order achieves a major milestone in the Reforming the Energy Vision (REV) initiative by beginning the actual transition to a distributed, transactive and integrated electric system," the commission wrote.

It would replace existing DER business models based on net energy metering, which the commission called "inaccurate mechanisms of the past that operate as blunt instruments to obscure value and are incapable of taking into account locational, environmental and temporal values of projects."

"By failing to accurately reflect the values provided by and to the DER they compensate, these mechanisms will neither encourage the high level of DER development necessary for developing a clean, distributed grid nor incentivize the location, design and operation of DER in a way that maximizes overall value to all utility customers," it said.

Continuing NEM, which can overcompensate distributed resources by transferring their share of fixed costs to other customers, would prevent wide-scale DER deployment "as the inherent subsidies reach a level that is oppressive to non-participants," the order said.

"The system obeys not the law of contracts, but the laws of physics," said PSC Chair Audrey Zibelman, in her final commission meeting. "Following those, that's how you'll get the best outcome. DER, rather than being a problem, can be a solution to where we want to get to, which is a clean energy future."



NEM compensation vs. DG value (hypothetical 2 MW PV) | *NYPSC*

Transition Period

The order initiates a transition period with a VDER Phase One tariff in which projects currently in "advanced stages of development" will receive NEM compensation, but for only their first 20 years.

"While Phase One NEM contains inefficiencies similar to NEM as a compensation methodology, the term limitation will offer some incentives for developers and customers to consider the impacts of the location, design and operation of DER on the electric system," the commission said.

The order directs Department of Public Service staff to work with utilities and other stakeholders to develop the new value stack compensation "based on monetary crediting for net hourly injections," which the commission hopes to act on as early as this summer.

Value stack compensation would include:

- Energy value, based on the day-ahead hourly zonal LMPs, including losses;
- Capacity value, based on retail capacity rates for intermittent technologies and the capacity tag approach for dispatchable technologies based on performance during the peak hour in the previous year;
- Environmental value, based on the higher of the latest Clean Energy Standard Tier 1 renewable energy certificate procurement price or the federal government's social cost of carbon; and
- Demand reduction value and locational system relief value, based largely on utility marginal cost of service studies

Continued on page 32

NYISO, PSC: No Worries on Replacing Indian Point Capacity

Continued from page 30

consumers' bills.

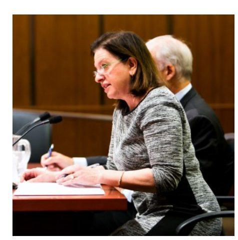
"Since prevailing wholesale prices are now lower than the cost of existing nuclear generation, it is anticipated that any new replacement power in the long run will be cheaper than continuing to buy power from Indian Point," she said.

Worries over Economic Impact

Also testifying was T. Michael Twomey, vice president of external affairs for Entergy's wholesale power business, who was questioned about the company's decommissioning plans and its offer to relocate laid off plant workers.

Much of the hearing was focused on the economic impact of the plant's closure, primarily the loss of the plant's property tax revenues and its 1,050 jobs.

On the morning of the hearing, Cuomo announced the formation of a task force to ease the impact on the community. "The task force will partner with local governments to address employment and property tax impacts, develop new economic opportunities" and retrain the work force, the governor's office said in a news release. "The task force will also monitor compliance with the closure agreement, coordinate ongoing safety inspections and review reliability and environmental concerns, among other issues."


Zibelman

NYISO NEWS

NYPSC Adopts 'Value Stack' Rate Structure for DER

Continued from page 31

and performance during 10 peak hours.

Decision Draws Praise from Solar Advocates

Clean energy supporters and solar industry advocates hailed the decision.

"The order will provide a framework for more precisely valuing new clean energy while balancing the need for a predictable price," said Anne Reynolds, director of the Alliance for Clean Energy New York. "This is the right approach and can serve to support the market for solar and other emerging clean technologies."

In a blog post, Natural Resources Defense Council attorney Miles Farmer called the order "a bold experiment."

"Rather than offsetting the retail rate, projects will generate credits according to an estimate of the value they provide to New York customers," he wrote.

Sean Garren, a regional director for Vote Solar, a nonprofit solar advocacy organization, lauded the "consumer savings, local jobs and a healthier environment" implied in the decision. "While this order has yet to fully expand clean energy access to all New Yorkers, we look forward to doubling down on that commitment to make community solar work throughout the state," he said.

Incentives for Utilities to Collaborate

The PSC also approved an order (Case 16-M-0411) on utilities' transition to the distributed system platform combining planning and operations with enabling markets.

The order directs Central Hudson Gas & Electric, Consolidated Edison of New York, New York State Electric and Gas, Niagara Mohawk Power (National Grid), Orange and Rockland Utilities, and Rochester Gas & Electric to submit filings by Oct. 1 documenting that they have completed their analyses of the hosting capacity for all circuits at and above 12 kV and implemented Phase 1 of their online portal for DER developers seeking to access the grid.

The companies also were ordered to submit filings within 60 days describing how the "suitability criteria" — a framework for identifying distribution infrastructure projects most suitable for non-wires alternatives — will be incorporated into their planning procedures and applied to current capital plans.

It set a Dec. 31, 2018, deadline for documenting that each utility has deployed at least two energy storage projects at separate distribution substations or feeders.

Tammy Mitchell, PSC chief for electric distribution systems, said, "The phased approach is right but too slow. This order directs hosting utilities to provide the hosting capacity data needed to manage the variable DER inputs."

"Today the advanced energy economy industry is worth $200 billion in the U.S.," Zibelman said. "This order points in the right direction, gives utilities the right incentives, and gives investors the transparency and data they need to put money at risk."

Helping Utilities See DERs as Customers

In its third and last vote on its regular agenda, the PSC approved an order (Case 16-M-0429) for an interconnection earnings adjustment mechanism, which aims to change the way utilities earn revenues.

The order requires the utilities to build on their previous filings with additional proposals within 60 days on customer service surveys and other metrics that will determine their future compensation.

"This is a good start to change the business model so that DER providers are customers of the utility, which want to attract them and not see them as competitors," said Zibelman. "Utilities should look at DERs as customers and see how they can exceed customer expectations."

Department of Public Service Deputy Director Michael Worden said the order "addresses the market in four categories: system efficiency, energy efficiency, consumer engagement and interconnection."

Depending on how they perform against targets in those categories, said Worden, the PSC will either "reward them with a carrot, or show the stick."

Zibelman's Swan Song

Thursday's meeting marked the end of Zibelman's more than three-year tenure, as she has accepted an offer to lead the operator of Australia's largest gas and electricity markets. (See *NY REV Won't Lose Momentum, Departing Zibelman Says*.)

Gov. Andrew Cuomo on March 8 appointed Commissioner Gregg C. Sayre as interim chair. The only other commissioner is Diane X. Burman.

Zibelman's departure, the recent retirement of Commissioner Patricia Acampora and a two-year-long vacancy means the commission now has three openings for new members.

A few months ago in an ISO not that far away…

PAR WARS

EPISODE I

A STRUGGLE FOR POWER

Unrest grows along the PJM-NYISO border after the dismantling of the CON ED-PSEG WHEEL that for decades held sway over daily operations in the region. Expensive infrastructure replacements loom on the horizon, and stakeholders on both sides suspect the other of attempting to take advantage of the situation.

At the RAMAPO SUBSTATION, a phase angle regulator has failed, sparking a dispute between territorial transmission owners that threatens to reignite longstanding, deep-seated grudges.

As a last resort, delegates from both sides of the border have journeyed to an unassuming office complex on the outskirts of Philadelphia to meet in person in the hope of averting chaos...

By Rory D. Sweeney

VALLEY FORGE, Pa. — If Friday's joint PJM-NYISO meeting to discuss replacing a phase angle regulator (PAR) at Consolidated Edison's Ramapo substation, near the New York-New Jersey border, had a "Star Wars"-like preamble crawling off into space, it would probably look something like that. Ok, maybe a bit less dramatic.

One of the substation's two PARs failed in June, and Con Ed has hesitated to replace it until it receives certainty on how it will be paid for. That has been in question because the 1993 agreement signed by NYISO (then known as the New York Power Pool) and PJM transmission owners is in dispute.

The agreement covered just the original PARs at the facility, PJM transmission owners argue, neither of which remains in service. They say Con Ed's decision in 2013 to replace the first failed PAR constituted a breach of the agreement, which requires the PJM transmission owners to be involved in the decision. Con Ed disagrees with that interpretation and believes the cost allocations under the contract — which would put PJM transmission owners who were a party to the agreement on the hook for 50% of the costs — remain in effect. However, stakeholders said that Con Ed's reluctance to replace the failed equipment without knowing how it will be repaid doesn't square with the company's argument for why it replaced the first PAR after its failure in 2013, without consulting transmission owners.

"It seems like your own decision not to replace the PAR is in violation of your own interpretation of the agreement," said Mark Younger of Hudson Energy Economics.

But before deciding on who should pay for it, some stakeholders are asking whether it needs to be replaced in the first place. In its current form, Calpine can't support the project's scope, company representative David "Scarp" Scarpignato said. "You really need to know what projects should be shared before you discuss sharing those costs," he said. "The cost of paying for the PAR is not the big deal here. It's that you're potentially using the PAR to change the winners and losers here."

He argued that the PAR helps alleviate congestion, which mutes the price signals on which generation companies like Calpine depend. "When you're talking about using transmission to manage congestion rather than dispatching to address congestion, that is direct competition to generation," he said.

Since the 1970s, operator and planners have operated under an agreement in which Con Ed wheels 1,000 MW of power through Public Service Electric and Gas' transmission system in northern New Jersey into New York City. Con Ed announced last year that it no longer needs the service and would be canceling it as of May 1. Con Ed also canceled its membership in PJM and ended all commitments for cost allocation in the RTO, despite having been the reason for a substantial amount of now-unnecessary transmission upgrades. PJM stakeholders have taken issue with being forced to take on additional financial responsibility for maintaining infrastructure that's no longer in use or being paid for by its intended beneficiary. (See *NYISO Members OK End to Con Ed-PSEG Wheel*.)

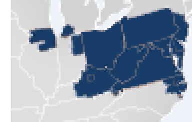
The Ramapo PARs were part of the wheel. PSE&G's Vilna Gaston asked if there had been an analysis regarding the benefits of replacing the PAR to determine if that's even the best investment. "It seems like we're proposing a solution before we do the investigation. This is putting the cart before the horse," she said.

Despite their disagreements, stakeholders reached consensus on a list of objectives for a potential analysis, including ensuring the endorsed solution adheres to competitive market principles and that the cost allocation is aligned with who receives the benefits.

PARs are an expensive solution. Beyond the millions of dollars in installation costs, PARs require about $200,000/month in upkeep, PJM's Stan Williams said. Additionally, NYISO allocates such costs through all of its load-serving entities, while in PJM, only the signatories to the original agreement would share the costs, so there is a larger group to distribute through in NYISO than in PJM.

The group's next meeting will be on April 18 at NYISO's offices.

PJM NEWS



PJM Sticks with LS Power on Artificial Island Project

By Rory D. Sweeney

VALLEY FORGE, Pa. — And the winner is ... LS Power, again.

Warren Beatty wasn't on hand, but PJM still received plenty of criticism Friday after planners reaffirmed — with some scoping changes — their previous selection of LS Power's proposal for the contentious and long-awaited reliability upgrades on Artificial Island.

The island on the southwestern edge of New Jersey is home to three nuclear reactors owned by Public Service Enterprise Group, which have been forced to operate for years below capacity and in accordance with a complex operating guide.

Last August, PJM's Board of Managers suspended the project for additional review after PSEG raised a series of engineering concerns and increased the cost estimate for its portion of the upgrades by at least $135 million. (See PJM Board Halts Artificial Island Project, Orders Staff Analysis.)

Scope, Costs Reduced

At Friday's special session of the Transmission Expansion Advisory Committee, PJM officials said their review confirmed that LS Power's proposal for a 230-kV line from Artificial Island to a new Silver Run substation in Delaware was the best solution but that the interconnection point should be changed from the Salem plant to Hope Creek. The analysis also determined that a static VAR compensator (SVC) at the New Freedom substation and optical groundwire upgrades provided little benefit and were unnecessary.

The planners' recommendations will be forwarded to the board for final approval.

In addition to eliminating those upgrades from the scope of work, planners recommended implementing a voltage schedule at the plants and revising the in-service date to June 1, 2020.

Much of the discussion on Friday focused on the project's costs compared to the other finalist, a project proposed by Public Service Electric and Gas that would follow an existing transmission route north through New Jersey.

PJM's analysis found that LS Power's project would cost $265 million, $11 million more than PSE&G's. But planners said LS Power's proposal, which contained hard cost caps, provided "greater cost certainty." PJM's Paul McGlynn, who oversees the project's development, said PSE&G's project also raised permitting concerns because it would run through the Supawna Meadows National Wildlife Refuge.

As approved in July 2015, the project was expected to cost $270 million to $283 million. The February 2016 update that prompted the suspension pushed the cost to $418 million with the Salem interconnection more than doubling to $152 million from a maximum of $74 million.

Replacing the Salem connection with one at Hope Creek will save $20 million, and eliminating the optical ground wire and SVC trimmed an additional $120 million. That brings the projected cost to $265 million, with a cost cap of $278 million — within the bounds of the original project cost estimates.

PJM also pointed out that LS Power has already spent about $6.5 million on preliminary work, so switching projects would mean writing off that expense as a sunk cost. The RTO acknowledged that PSEG has also spent money on developing work estimates for PJM regarding its project, but "didn't think" to quantify it, said Vice President of Planning Steve Herling.

Stakeholders from PSEG and Dominion were among those criticizing PJM's new recommendation.

More 'Granular Review'

PJM said the suspension allowed time to conduct a "more granular review and re-evaluation" of the project, including additional site visits and marine and terrestrial surveying, a review of permits, property rights and scheduling issues and preliminary engineering.

Planners determined the optical groundwire and related line relay changes would not impact the site's operating guide or improve stability margins because of the timing of the most critical bus fault's clearing. They said if a need is identified for the upgrades later, they would be pursued as a separate project.

The SVC was replaced with a recommend voltage schedule for Salem and Hope Creek requiring operation at a minimum of 527.5 kV, a level PJM said was "maintained in nearly all conditions since 2012."

PSE&G insisted its proposal was "more robust" than LS Power's, providing larger stability and system reliability margins and — because it would employ a 500-kV line — more than three times more capacity than its competitor's 230-kV line.

PSEG's nuclear division sent the PJM board a letter March 2 warning that it has an option to build another reactor at the Hope Creek station and that the connection at Hope Creek might have to be moved if it moves forward with another reactor. Herling said PJM has no control over that and that future work at the site would need to be reviewed on a "case-by-case" basis.

LS Power's Sharon Segner said it's not an "apple-to-apples" comparison because PSEG's proposal excludes any overruns for environmental permitting and real estate rights, while her company's includes risks for both. In addition, LS Power has already contracted for material portions of its project, so the revised, lower cost estimate of $133 million for its portion reflects some actual contractual numbers.

PSEG's Jodi Moskowitz said that most of the costs in her company's proposal are capped.

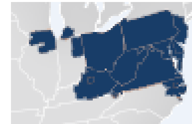
Old Dominion Electric Cooperative's Mark Ringhausen said it was "deceiving" to use $265 million for LS Power's project when that is only the company's current estimate. The proposal is actually capped at $278 million. LS Power's estimate assumes PSEG's work at Hope Creek costs no more than $132 million. However, this portion of the project has no cost cap.

First Order 1000 Project

PJM made the Artificial Island upgrades its first competitive solicitation under the FERC Order 1000 in 2013. In 2014, PJM planners recommended PSE&G for the job,

Continued on page 35

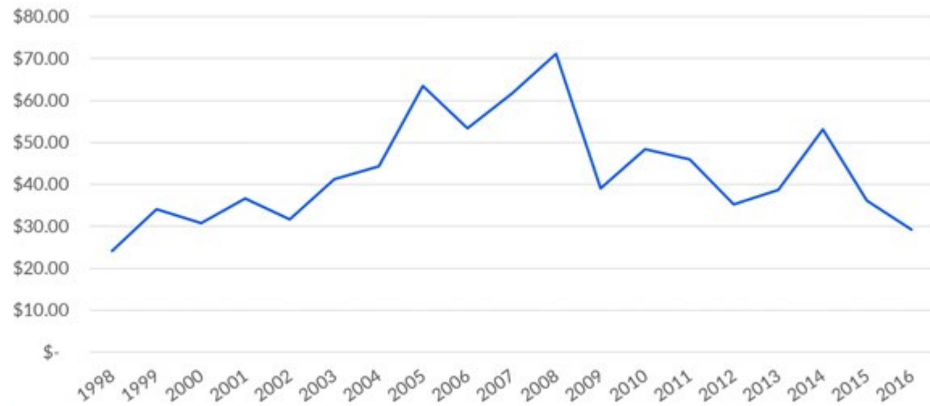
PJM News



PJM Monitor Concerned About State Subsidies

Bowring Finds Markets Competitive amid Record-low LMPs

By Michael Brooks



PJM real-time yearly load-weighted average LMP | *Monitoring Analytics*

WASHINGTON — PJM Independent Market Monitor Joe Bowring on Thursday warned that state plans to subsidize unprofitable generating resources present "a very real threat" to wholesale electricity markets.

The subsidies in question come in the form of zero-emission credits for uneconomic nuclear plants, which were included as part of New York's Clean Energy Standard and are intended to aid the state's transition away from fossil fuels and into renewables.

Exelon has been pushing for similar treatment for its nukes in Illinois, while FirstEnergy has said it will seek financial assistance for its Ohio plants.

"I don't believe that any of the subsidies are being driven initially by state policy," Bowring said during his PJM 2016 State of the Market Report presentation. "They're being driven by the specific requests of generation owners about particular units because those units are not profitable. We would not be talking about the units in Illinois or Ohio if the capacity market prices had been higher and those units were profitable."

Social goals — such as the reduction of carbon emissions to reduce the effects of climate change — can be accomplished through market-based solutions, such as a price on carbon, Bowring contended.

"Economists everywhere agree that … the most cost-effective way to do that is have a carbon price," Bowring said. "It's certainly not by picking individual power plants that are low carbon."

To protect the markets from the effects of the subsidies, Bowring advocated for applying PJM's minimum offer price rule (MOPR) to all existing resources. The rule currently covers only new subsidized gas-fired plants.

"Action is needed to correct the MOPR immediately," the Monitor said in its report. "An existing unit MOPR is the best means to defend the PJM markets from the threat posed by subsidies intended to forestall retirement of financially distressed assets. The role of subsidies to renewables should also be clearly defined and incorporated in this rule."

Bowring expressed concern that Illinois and Ohio could set a precedent for other states, calling the subsidies "contagious." The Monitor views the threat as so severe that in January it filed as an intervenor in support of independent power producers opposing New York's ZEC program.

"The ZEC program is not consistent with the operation of a competitive wholesale electricity market," the Monitor told the

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PJM Sticks with LS Power on Artificial Island Project

Continued from page 34

but the board reopened the bidding following an outcry from losing bidders, environmentalists and New Jersey officials. LS Power's project was recommended in April 2015, with PSE&G and Pepco Holdings Inc. chosen for necessary connection facilities. (See *PJM Staff Picks LS Power for Artificial Island Stability Fix; Dominion Loses Out*.)

That wasn't the end of the controversy, however. Delaware and Maryland officials have complained that most of the cost of the project would be allocated to ratepayers on the Delmarva peninsula despite the region receiving little benefit from the upgrade.

Last April, FERC approved the cost allocation for the project, but in June it said it would consider rehearing requests over whether PJM's use of the solution-based distribution factor (DFAX) cost allocation method is appropriate for the project (EL15-95, ER15-2563). (See *FERC Taking Second Look at Cost Allocation for 2 PJM Projects*.)

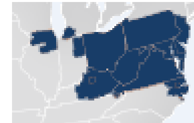
The commission cannot resolve the dispute until new members are appointed to restore its quorum.

Next Steps

Herling said the board will be educated about all of the cost estimates through comprehensive documentation, and "I guarantee they'll read all of it."

The next board meeting is scheduled for April 6, so PJM asked that all stakeholder comments on the recommendation be filed by March 31. Stakeholders expressed concerns that PJM won't have published its comprehensive whitepaper on the topic by then, so all comments will have to be based on existing documents.

PJM NEWS



Market Implementation Committee

FTR Lateness Blamed on High-Volume Period

VALLEY FORGE, Pa. — PJM's Asanga Perera came to last week's Market Implementation Committee meeting prepared to seek forgiveness. But instead of *mea culpa*, his message was: "Help Wanted."

Perera

PJM's Tariff requires that it post monthly financial transmission rights auction results within five days, but a series of emails to stakeholders made it clear that wasn't going to happen this month. PJM was eventually able to post the solution on March 1, and all paths were awarded for the full period.

That said, Perera noted this is the second time in as many years that results of the March auction have been late. An analysis found three contributing factors. Bid volumes and transmission outages played a role, he said, but the major issue was overlapping periods.

Every quarter, four auction periods occur simultaneously, stretching PJM staff and resources to their limits. Perera noted that some staff worked throughout the night to make even the relaxed deadlines. In March, the markets for March, April, May and fourth-quarter auctions are available. The other months with four open periods are June, September and December.

Perera solicited stakeholder feedback, noting that the issue may impact approval of residual auction revenue rights.

In other FTR news, PJM said it will file Tariff changes documenting its new FTR forfeiture rules by April 19. The rules will be retroactive to Jan. 19 — the date of FERC's order finding PJM's current rules not just and reasonable — once the appropriate tool is built. The new approach will include several tests to determine the FTR's impact. Additionally, the forfeiture is only for FTR profits. PJM plans to discuss FTR thresholds and review related Tariff and manual changes at the April MIC meeting. (See *FERC Orders Portfolio Approach for PJM FTR Forfeiture Rule*.)

PJM will also be bringing for endorsement next month revisions to Manual 6 to conform with FERC's FTR compliance order in January, along with other compliance directives.

Vitol Accepts Simplified Solution to Spot-In Issues

Vitol's Joe Wadsworth, who has urged PJM for years to rectify issues with its spot-in transmission service procedures, said he is willing to accept a smaller revision that

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PJM Monitor Concerned About State Subsidies

Continued from page 35

New York Public Service Commission, adding that the program would artificially suppress NYISO, dissuade the construction of new generation and, if extended, "result in a situation where only subsidized units would ever be built."

Record-low LMPs in PJM

The Monitor found that PJM's energy, capacity and regulation markets were competitive during 2016. The average real-time, load-weighted LMP was $29.23/MWh, 19.2% below the previous year and the lowest since the competitive wholesale market commenced operation in 1999 — "which is fairly astonishing," the Monitor noted.

Fuel prices were the main drivers: Gas prices were very low, while those for coal remained flat. High output from efficient combined cycle units — despite flat load growth — also played a significant role.

All those factors translated into a competitive market, Bowring said.

"New combined cycles have been added because of competitive markets," he said. "They've been added because of the fact that we have a capacity market. … But for PJM overall markets, we probably would not have seen that level of entry of highly efficient combined cycles."

As a result, net income for new combustion turbine and combined cycle units were up 21% and 14%, respectively. Meanwhile, profits decreased for new coal (54%), diesel (86%), nuclear (26%), wind (19%) and solar (28%).

Total transmission congestion costs fell by $361.6 million (26.1%), the result of low prices and smaller price differences across constraints.

Capacity Market

Capacity prices were lower last year than in 2015, except in the PSEG zone. Capacity revenue accounted for 43% of total net revenues for new combustion turbine plants, 32% for new combined cycles and 23% for new nuclear.

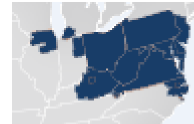
Total installed capacity last year rose 2.7% to 182,449 MW. As of Dec. 31, 101,474 MW were in the generation interconnection queue, with combined cycle units accounting for 68.3% and wind projects 14.4% of capacity. The Monitor expects gas to surpass coal in installed capacity this year.

Demand Response

Total payments to demand response resources decreased by $163.2 million (20.1%) to $655.7 million. Bowring attributed the decline to low prices, which undercut incentives to reduce power usage.

The capacity market remains the primary source of income for DR, making up 99% of its revenue — something Bowring is still not happy with, as he continues to advocate its removal from the capacity market. He said stakeholders are seriously considering the "best way" to manage those DR resources within the market.

"It's important to understand our perspective here, which is not anti-DR at all," Bowring said. "We're very much pro-DR. We think it's essential to making markets work. We want more people to have the option … to reduce demand and save capacity revenues."



Market Implementation Committee

Continued from page 36

would better align daily timelines for when the service is granted.

Wadsworth had been campaigning for a much more sophisticated market-based solution that would apply only to the NYISO seam. The Independent Market Monitor objected that any changes to border operations should apply to all seams. (See "Spot-in Transmission Analysis Expanded to all Interfaces," *PJM Market Implementation Committee Briefs*.)

"I always hate to surrender, but I don't think it makes sense to pursue [the more-sophisticated plan], especially if PJM doesn't support it," Wadsworth said. "But there's significant room for improvement there, not just on the issue I've raised but on other issues too."

He said the challenge with stakeholder leadership — in this case, on cross-border issues — is trying to wrangle both grid operators. Although he said the issue deserves a more comprehensive look by NYISO and PJM, PJM wouldn't support NYISO's requirement that it distribute any costs it incurs to PJM stakeholders. The grid operators have been unwilling to proactively address the issue without his insistence, Wadsworth said.

PJM agreed that the issue deserves a closer look.

"It's tough to say there's not things to improve there," said PJM's Adam Keech, who oversees market operations. "To the extent that stakeholders wanted to take a look at the issue, I would probably say we should look at all the interfaces and not just New York."

Pacella

Calpine's David "Scarp" Scarpignato asked about the prudence of making seams changes without acknowledgement from the other grid operator. PJM's Chris Pacella, who has led the analysis on the spot-in issue, said PJM has changed its internal procedures — deadlines in this case — and not heard back from NYISO about any problems.

Suction Level Revisions Endorsed Despite Stakeholder Reluctance

Stakeholders approved by acclimation amendments brought by the Independent Market Monitor to a problem statement and issue charge to address minimum tank suction level (MTSL) costs. The vote was quick even after NRG Energy's Neal Fitch pointed out that the issue was likely considered when annual revenue requirements for black start units were initially discussed.

"I have to believe this topic was discussed then, so why are we discussing it again?" he asked.

PJM's Tom Hauske explained that, under the current rules, generators can over-recover their costs for keeping the fuel available. (See "PJM Looking to Avoid Lump-Sum Billing on New Black Start Units," *PJM Market Implementation Committee Briefs*.)

The Monitor provided an illustration of a generator with a fuel tank capacity of 4 million gallons and an MTSL of 800,000 gallons, 48,000 gallons of which is the black start portion.

PJM's original method would allow recovery of the carrying costs on the full 800,000 MTSL, while the Monitor would allow recovery of costs for only 48,000 gallons. "The actual incremental amount of MTSL that results from the addition of black start capability is zero," the Monitor explained.

Hauske also presented an updated issue matrix for the initiative on annual revenue requirements for new black start units. "At this point in time, I think we're pretty close" to consensus, he said.

NOPR Analysis: Uplift Bad, Fast Start not Good

PJM staff gave the MIC their analyses of recent FERC Notices of Proposed Rulemaking, making clear they have some strong opinions. Regarding the NOPR on uplift, PJM's Rebecca Stadelmeyer said the RTO doesn't support it.

Asked if she could explain why, she said: "Absolutely, I'd love to. I thought we might skip right over that."

FERC's first proposal would create two categories for real-time uplift costs associated with deviations: systemwide and congestion management, and charge uplift only in accordance with cost-causation principles. Stadelmeyer said it could be done, but that PJM doesn't support any parts of the NOPR. (See "Members Approve Uplift Proposals," *PJM Markets and Reliability and Members Committees Briefs*.)

More important, Stadelmeyer said, was FERC's second proposal to distinguish between helpful and harmful deviations and allocate uplift only to harmful ones.

"We've continuously said that we cannot find a non-subjective way to isolate whether those deviations help or harm the system," she said.

There was also some disagreement on the intentions of the NOPR. DC Energy's Bruce Bleiweis said it stated "fairly strongly" that costs should be allocated to load.

"That wasn't our read," Keech said. "If they wanted it to be allocated to load, they probably would have said that."

On the fast-start NOPR, PJM appeared largely indifferent until it came to relaxing the eco-min of fast-start resources. Doing so "will likely create significant over-generation concerns," PJM wrote in its presentation. The change could exacerbate already complex uplift allocation methods. (See *FERC: Let Fast-Start Resources Set Prices*.)

"No analysis could be indicative or identify what the tradeoff would be," PJM's Lisa Morelli said. "It would not be a wash. There would likely be a difference between the uplift paid to fast start and the [lost opportunity cost] of resources."

FirstEnergy's Jim Benchek asked her to guess at which would be higher, but she said she wouldn't. Citigroup Energy's Barry Trayers said that it appeared that much of FERC's opinion came from a "MISO foundation," along with lessons learned, when other ISOs/RTOs might have more robust and efficient procedures.

The Monitor largely agreed with PJM's opposition. "[For] those of you who haven't read our comments, we think the NOPR is a terrible idea," Bowring said. "We don't think the solution is to change the definition of fast start. We think the appropriate way to handle this is to think of it as a tradeoff."

— Rory D. Sweeney

PJM NEWS

Operating Committee Briefs

System-Restoration Drill Successful Despite Lack of ACE Control

VALLEY FORGE, Pa. — PJM's two-day spring restoration drill succeeded in recovering from a hypothetical blackout, but operators couldn't re-establish the area control error because the simulation lacked necessary state-estimator data.

"We'll work on that for next year," PJM's Ryan Lifer told members at last week's Operating Committee meeting.

On Day 1, the initial focus was on energizing black start units to establish cranking paths to ensure safe shutdown of all nuclear facilities. Transmission owners, all of whom were required to participate for NERC compliance, were informed there was no outside assistance. By Day 2, participants were allowed to call in outside resources. PJM worked with members to identify possible tie opportunities, and Lifer said "quite a bit more" were established compared to previous drills. However, there could have been more.

"I think a lot of members focused on establishing internal load before making ties, so we need to encourage building up [reinforcing] the RTO," he said.

PJM Seeks to Tap Synchrophasors' Potential

Synchrophasor technology has advanced to being "really in the sweet spot from transitioning from science project to useful product that we can use in the control room," PJM's Ryan Nice explained.

Synchrophasors are meters that provide instantaneous real-time data, like SCADA systems but with considerably less delay. The information could be very valuable, Nice said, but only if it's utilized in a meaningful way. "If you don't do anything with the data, no value is being generated," he said.

Part of the issue with synchrophasors is that no one knows their true potential. There is potential, Nice said, for revolutionary applications, such as increasing infrastructure resiliency and compiling the data into system-management tools that can react in real time. One tantalizing possibility is using the data for state estimation without any energy management system (EMS) SCADA input, he said, which would create a state estimator that is almost entirely redundant to the EMS SCADA. Because state-estimator data underpins so much of what PJM does, "even a very marginal improvement in the state estimation improves a whole plethora of other services," he said.

First, however, resources must be allocated to foundational research, such as simulator training and model validation.

"To buy your roll of the dice [and] get your shot at the really high-value, real-time [applications], you've got to do these lower quadrants," he explained.

For example, PJM has installed some synchrophasor-related applications in its control room, but they aren't supported well and operators haven't been trained effectively on how to use them. Nice's group is developing a simulator for oscillation detection that will interact with trainees like "Choose Your Own Adventure" children's books. Trainees will be presented with a situation and given options to respond. The simulator will provide feedback on the consequences of the trainee's decision, along with the next decision to make. It's a "deeper cut of training than we've ever been able to pull off before with this information," Nice said.

Oscillation detection is important to prevent major system imbalances, but oscillations are very difficult to identify because they can happen between any two points. "This new technology is agnostic about points A and B and just searches for oscillations everywhere," Nice said.

While the technology is exciting for system operators, stakeholders were concerned about what such critical advances might mean for industry standards and compliance requirements.

Exelon's Ken Braerman asked if and when Nice expected synchrophasor information to become operationally critical and for his prediction on how many compliance standards would be promulgated affected individual stakeholders.

"We are hyper-sensitive to these issues, and right now we do not consider synchrophasor applications to be NERC or Critical Infrastructure Protection standards-critical," Nice said. "You can live without this, but it's good data to have. Right now, we don't know when we cross that threshold that you can't live without this."

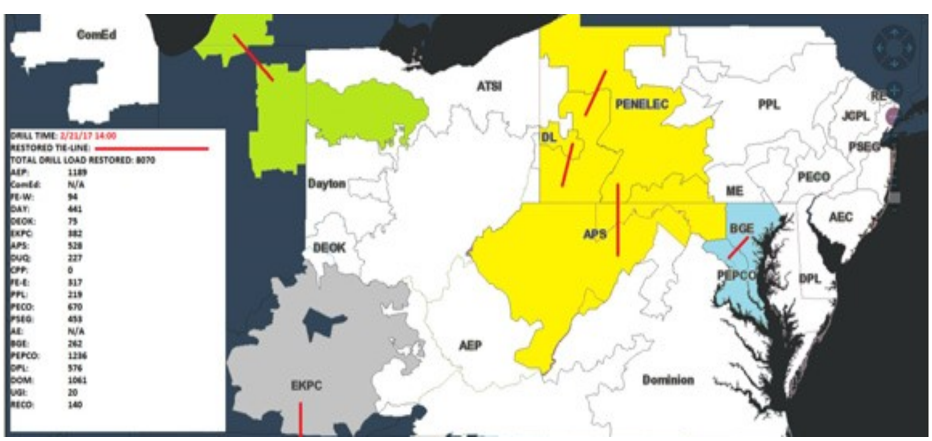
Countdown to GridEx

GridEx, NERC's biennial grid-resilience exercise, is scheduled for Nov. 15 and 16, PJM's LeRoy Bunyon said. This year's exercise will focus on cyber and physical attacks that degrade bulk-power system operations.

Of particular interest will be the "cyber kill chain," which creates a multilayered defense against online attacks. Bunyon said it helps to determine how deep hackers have infiltrated once their presence is identified: "Have they picked the lock? Have they opened the door? Are they in your kitchen? Are they carrying the safe out the door?"

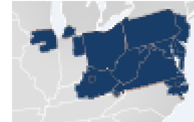
The event organizers will gather lessons learned and develop a report for senior leadership.

— Rory D. Sweeney



PJM black start drill — Day 1 results | *PJM*

PJM NEWS



PJM Fuel-Cost Policy Changes to Take Effect in May

By Michael Brooks

VALLEY FORGE, Pa. — PJM expects to implement its new fuel-cost policy rules on May 15, PJM's Jeff Schmitt told the Market Implementation Committee last week. That would require generators to file any policy changes by March 15 to guarantee approval before the transition date.

Schmitt

Despite its looming implementation, the new rules continue to raise substantial questioning from stakeholders, which PJM is attempting to address with a FAQ document.

On Feb. 3, FERC largely accepted PJM's proposed rule changes, siding with the RTO in requiring that policies be verifiable and systematic but not algorithmic, as Monitoring Analytics, the Independent Market Monitor, had proposed. (See *FERC Seeks More Details on PJM Fuel-Cost Policy Proposal*.)

The Monitor said the policies should be based on a simple average of broker quotes, bilateral offers or a weighted average index price posted on the Intercontinental Exchange (ICE) trading platform. The commission said the Monitor's insistence that policies be "algorithmic under all circumstances" ignores how natural gas markets operate during stressed conditions that may make them illiquid, potentially understating generators' real costs.

The Monitor pointed out that the term "algorithmic" is misunderstood by PJM and by FERC. Algorithmic simply means a step-by-step process to get from a defined input to an output, the Monitor says. it is therefore virtually impossible to have a verifiable policy that is not also algorithmic.

Schmitt, the manager of market analysis, said PJM's verification documents the steps taken daily to develop cost-based offers that do not change based on variables. He walked through the documents necessary for an approved policy, including filing a numerical example for each cost-based offer, likely on a spreadsheet, in the Monitor's Member Information Reporting Application.

While generators' decisions won't be challenged during the policy review, it's critical for them to note whether they include emissions and variable operations and maintenance in their offers, he said. The Monitor has required a numerical example for all approved fuel-cost policies for more than two years.

Stakeholders expressed concern that the rules for dual-fuel generators appeared to not allow the flexibility to switch between fuels as desired, essentially requiring a forced outage. PJM and the Monitor said that the preferred resolution would be to create a cost-based offer for each fuel type.

Mooney

FERC made "a pretty strong statement" on the separate fuel-type offers, and that "flies in the face of only needing one cost-based offer for dual-fuel units," said Catherine Tyler Mooney of Monitoring Analytics.

"If we commit you on a gas schedule, and you run on oil, that risk exposure is 100% yours," said Adam Keech, PJM executive director of market operations. "Our intention is not to put you on a forced outage when you have fuel."

As long as a generator has an approved cost-based offer, "we think [it] should be able to switch as needed based on physical requirements," Monitor Joe Bowring said.

PJM and the Monitor also addressed ongoing questions about their relationship in approving policies. The sides appeared to have settled their differences, as the tone of their comments were markedly less confrontational than they had been at recent meetings. (See *Stakeholders Caught in PJM-IMM Dispute over Fuel-Cost Policy*.)

"Once we've been through reviewing the policies, it makes it easier for PJM," Bowring said. "I can't think of one we've approved that PJM hasn't approved. … It's proven efficient to go through us first."

"It's been helpful for PJM folks to be in listening mode during the IMM negotiations," said Stu Bresler, PJM senior vice president of operations and markets.

However, the Monitor's late submittal of proposed revisions in Manual 15 regarding its role in the policy-review process created some heartburn among stakeholders.

Greiner

Before the agenda had even been discussed at the beginning of the meeting, Gary Greiner, director of PJM market policy at Public Service Enterprise Group, questioned why the Monitor had been allowed to file such a late addition. Bowring responded that when his group must respond to late filings, it becomes impossible to avoid filing them late himself.

Mooney explained that the Monitor's proposed changes would enunciate the separation between it and PJM in the approval process.

"Working together is happening, but it should be clear that the reviews are separate," she said.

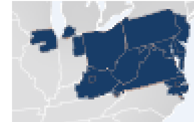
O'Connell

Bob O'Connell of Panda Power Funds questioned why the Monitor elected to propose that it "may" provide its recommendation regarding policy approval to PJM in writing. He requested that it be changed to "shall."

"Not having that recommendation in writing is troublesome," he said.

Bowring responded that the Monitor plans to provide its recommendations in writing and that it is always very clear with market participants about issues with fuel-cost policies.

PJM NEWS



UTC Trader Displeased with PJM's Handling of Uplift Rule Changes

By Rory D. Sweeney

"These actions are strongly affecting market participants' confidence in PJM's 'neutral' administration of its duties ..."

XO Energy

A financial trading firm accused PJM of unfairly discounting the interests of up-to-congestion traders in recent rule changes that it says would shift hundreds of millions in uplift charges to them from load.

"PJM is required to act as a neutral body without giving priority to one sector over others. XO is concerned that the packages promulgated by PJM and its [Independent Market Monitor] … benefits load while producing great harm to the Other Supplier Sector, including the financial community," XO Energy President Shawn Sheehan wrote in a Feb. 24 letter to the Board of Managers.

The letter follows a phased set of rule changes that was overwhelmingly endorsed by the Markets and Reliability Committee in January and the Members Committee in February. (See "Work on Uplift Moves Forward Despite NOPR," *PJM Markets and Reliability and Members Committees Briefs*.)

Phase 1 includes in the determination of balancing operating reserve credits only the day-ahead revenues from the hours the resource operated in real-time, not all day-ahead revenues. Phase 2 includes UTC transactions in the allocation of day-ahead and balancing operating reserves in the same way as incremental offers and decremental bids. It would also remove the ability for internal bilateral transactions to offset deviation charges.

XO argues in its letter that the changes create a "triple capacity deviation," although UTCs are intrinsically transmission products that don't impact capacity. According to XO's calculations, the changes will shift as much as 79% of the total real-time uplift charges and 25% of day-ahead uplift to UTCs — a total of more than $388.5 million.

The letter argues that PJM actively worked to force the changes through the stakeholder process and didn't offer XO and its allies due process.

"XO is concerned that equitable, stakeholder-centric initiatives, which do not comport with fundamental market design principles, such as best practices and causation, are taking precedence" to sound market design, the letter reads. "In the past year or more, XO has witnessed an unwarranted negativity from PJM and its staff towards both financial products and the financial trading community. … Financial market participants feel bulldozed by PJM's perceived priority in advancing its own proposals through the voting process and its favoritism of other [stakeholder] sectors. These actions are strongly affecting market participants' confidence in PJM's 'neutral' administration of its duties and its operation of a fair and efficient market."

PJM did not immediately respond to a request for comment.

The complaint is the latest chapter in a long-running battle among PJM stakeholders over the value of financial products such as UTCs and whether they are paying their fair share of costs.

FERC weighed in on the issue in its Jan. 19 Notice of Proposed Rulemaking on uplift and UTCs. (See *FERC Proposes More Transparency, Cost Causation on Uplift*.)

XO contends that PJM ignored FERC's direction in its proposed Phase 3 package that would limit UTCs to zones, hubs and aggregates. Such changes "would effectively remove the products' ability to mitigate local market power and converge nodal congestion," the company said. "FERC has repeatedly held that convergence of the day-ahead and real-time markets is a key measure of market efficiency."

PJM Refunding $41M to Bilked Market Players

PJM has received FERC approval to divide $40.8 million from an enforcement settlement with GDF SUEZ Energy Marketing among market participants who were impacted by the company's scheme to improperly capture make-whole payments.

FERC's Office of Enforcement, which reached the settlement with GDF, approved of PJM's plan to distribute the funds as negative operating reserve charges to any market participants that incurred deviations between the day-ahead and real-time energy markets between May 2011 and September 2013, according to an email from David Budney, the RTO's manager of market settlements. It noted that the adjustments have been processed and are available in the market settlements reporting system.

The funds are part of a nearly $82 million payment by GDF to settle market manipulation charges for offering generation below cost to capture make-whole payments in PJM. Enforcement charged GDF with violating the commission's Anti-Manipulation Rule for an improper bidding strategy designed to increase its receipt of lost opportunity cost credits (LOCs).

According to the settlement, the Houston-based power marketer offered below-cost bids on some of its 12 natural gas-fired units to clear PJM's day-ahead market and profit off the LOCs when the units weren't dispatched in real time. GDF used a probabilistic, risk/reward approach to compare when units were unlikely to be dispatched against the risk of running the units at a loss, the settlement said. (See *GDF SUEZ to Pay $82M in PJM Market Manipulation Settlement*.)

GDF's parent company rebranded as ENGIE in 2015 and sold off its U.S. fossil-fuel generation assets in 2016. PJM has since updated its rules to eliminate the loophole of which GDF took advantage.

— Rory D. Sweeney

PJM NEWS

PC/TEAC Briefs

Winter Resource Adequacy Analysis Raises Questions

VALLEY FORGE, Pa. — General assumptions regarding winter operations will need to be replaced with actual data to improve PJM's winter resource adequacy analysis, staff told the Planning Committee last week.

"There's a propensity for our load model to under-forecast the winter load," PJM's Tom Falin said. "This is of concern to us."

The analysis also found that while the generation forced outage rate for winter rose just 1% from 2007 to 2015, winter's standard deviation is 4%, more than double the 1.7% for summer. Falin presented a graph that highlighted the increased uncertainty, showing that in one winter week, the forced outage rate could be anywhere from 4 to 12%. Noting that as many as 181 transmission elements, including lines and transformers, were on planned maintenance at some point during January, he questioned whether they could result in deliverability problems.

"To get a handle on that will be a challenge for us," he said, adding that it's another area that's not being fully captured in PJM's loss-of-load expectation (LOLE) studies.

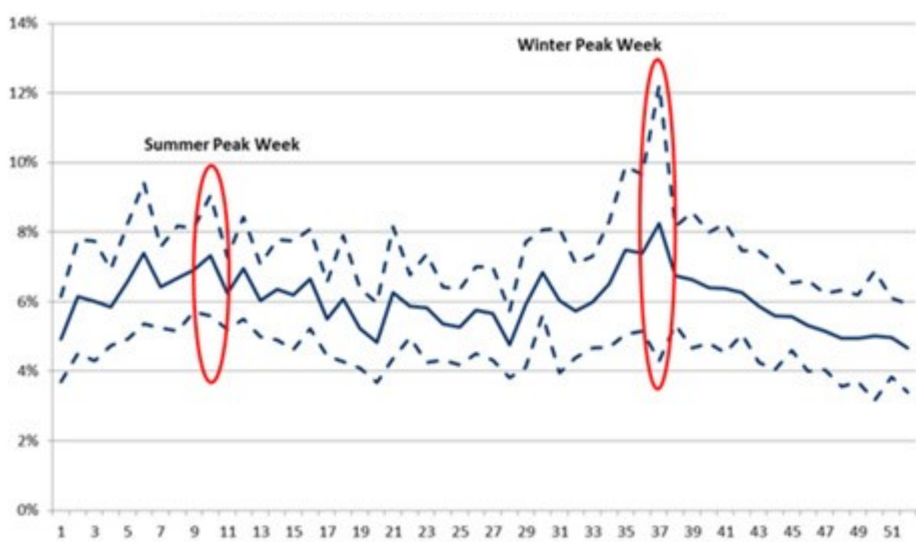
One area to look at might be equivalent forced outage rates – demand (EFORd), which measures the probability that a unit will fail when needed. PJM's current EFORd calculation is an annual measurement that is independent of other EFORds, weather and other variables.

Falin questioned whether it made sense to develop EFORds that consider seasonal variables. Additionally, the class averages for wind and solar are based on summer measurements, which underestimates wind's winter availability while overestimating that for solar.

Another issue is modeling. PJM's modeling tool, PRISM, "is going to say there's virtually a 0% chance of a 13% outage rate," Falin said. "The problem is we've seen it."

"We may be getting to a point where wind [generation] captures a big-enough share where we should start capturing turbine's actual performance and not just assume it's 13%," he said.

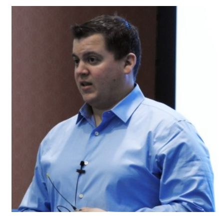
In November, stakeholders approved a problem statement and issue charge to review PJM's load forecasting and planning models and methodologies to determine whether the RTO is properly calculating the amount of capacity needed in winter to meet its LOLE targets. The initiative was proposed by economist James Wilson on behalf of consumer advocates for Maryland, New Jersey and Delaware. Wilson and others have questioned why the summer-peaking RTO requires identical amounts of capacity in summer and winter. (See PJM Stakeholders Reject CP Rule Changes, OK Additional Study.)



Weekly effective forced outage factor | *PJM*

Staff Moving Forward on Memorializing Competitive Planning Process

PJM staff presented the PC with the first product of their meetings on redesigning the Transmission Expansion Advisory Committee, a new Manual 14F: Competitive Planning Process. The manual mostly codifies processes that previously had been done informally. (See PJM Making Cost Consciousness a Focus for RTEP Redesign.)



Herman

PJM's Mike Herman, who is overseeing the project, said he had been told by Dave Anders, the keeper of all institutional knowledge regarding the RTO's stakeholder process, that he can't remember the last time it created a new manual. "So we in planning must be doing something right," Herman joked.

While PJM acknowledged it's already received substantial feedback about the manual, staff urged stakeholders to provide all comments for next month's meeting.

Herling

"We would like to move this along next time," Vice President of Planning Steve Herling said. "We would really appreciate people going through it [and bringing any issues to the April meeting]. The only way we're going to find out if this works really well if you all test it out and tell us what you like."

Public Service Electric and Gas' Alex Stern foresaw an enforceability issue. "Although it is true that PJM hasn't policed incumbent transmission owners to ensure they are building to minimum design standards, they've never had to because state officials more than do that job," he said. When there's a problem, customers often call state officials, who call the local utility.

"What happens next is typically things get fixed so that calls ... don't happen further and customer service is at an appropriate level," Stern said. "State officials aren't going

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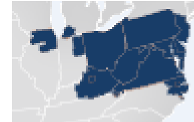


PC/TEAC Briefs

Continued from page 41

to know [whom to contact at non-incumbent transmission developers]. When something's not working, they're likely going to call their local utilities and PJM's government relations people."

Herman also presented proposed administrative updates to Manual 14B to change all occurrences of "special protection system" to "remedial action scheme" per a change to the NERC glossary of terms.

New Design Requirements and Procedure Developments Presented

The Designated Entity Design Standards Task Force introduced its first product at the PC meeting: a document setting standards for overhead transmission. The task force will also be developing standards for substations, system protection, control design and coordination, staff said.

PJM also presented its planned structure for complying with standards released last fall by NERC on geomagnetic disturbance events. The structure includes a five-year implementation schedule that won't produce assessment results until 2021. Full GMD vulnerability results won't be available until 2022, when PJM plans to begin developing any necessary corrective plans.

PJM Offers Four RMR Contracts

PJM told the TEAC it has offered generation owners in New Jersey and Virginia reliability-must-run contracts for four units, all of which have received FERC approval.

The New Jersey units — Rockland Capital's coal-fired B.L. England Units 2 and 3 in the Atlantic City Electric transmission zone — were asked to run until previously approved baseline transmission upgrades are completed. The upgrades were expected to be completed within the next two years, but delays to related projects have made the timeline indeterminate.

PJM also is asking Dominion Energy to keep

Yorktown plant | *Dominion*

operating its Yorktown coal-fired Units 1 and 2 until a transmission solution is approved. The plants, on Virginia's middle peninsula, have been the focus of years of controversy. Their license was extended to April, but environmental groups have been pushing for their closure. Dominion has sought support for installing a 500-kV line from the mainland to the south, but environmentalists have fought that as well. Without approval of the transmission line, PJM has identified reliability issues that would arise if the Yorktown units close. (See *Dominion Says Blackouts the Only Solution for Va. Peninsula*.)

— Rory D. Sweeney

MISO, PJM Propose Rebates to Solve Double-Counting of Pseudo-Tie Congestion

Continued from page 27

Vannoy said the rebate will be based on physical transmission usage charges, and not on a pseudo-tie transaction basis. He also said MISO already provides congestion rebates through financial transmission rights, so he didn't see it as "appropriate" that the RTO would only charge once and offer rebates twice.

Stricter Rules Coming

Both PJM and MISO are also focused on introducing stricter pseudo-tie rules.

Vannoy said MISO's more stringent pseudo-tie process will be filed with FERC in the "near term," despite staff putting the proposal on hold to better explain it to its stakeholders. (See "RTO Delays Filing Pseudo-Tie Proposal," *MISO Advisory Committee Briefs*.)

Tim Horger, manager of interregional coordination at PJM, said his RTO will soon file its own more stringent pseudo-tie rules with FERC as well. Last month, stakeholders approved more stringent rules for new pseudo-tie applications but declined to endorse them for existing pseudo-tied units. PJM announced that it is going to file the new rules for FERC approval for both new and existing pseudo-ties. (See *PJM to Tighten Pseudo-Tie Rules Despite Stakeholder Pushback*.) A first-ever PJM pseudo-tie *pro-forma* agreement, however, was postponed after stakeholder concerns.

PJM and MISO pseudo-tied 2,061 MW of transfers for the 2016/17 planning year, compared with 156 MW during the previous year.

The increased pseudo-ties have produced more congestion and brought more attention to pricing discrepancies along the border between the RTOs, which can result in revenue imbalances between RTOs and increased uplift payments in addition to the double counting of congestion. The RTOs last year said MISO would use data from December 2016 to begin an analysis of pseudo-tie congestion in mid-2017.

The RTOs will also adopt a new common interface definition beginning June 1, moving from about 1,800 nodes inside PJM to a common interface consisting of 10 nodes close to the seam. Beibei Li, of MISO's market evaluation and design team, said the change will reduce congestion overlap.

"We're moving from a fairly large interface definition to something closer to the seam," Li said.

A 2016 MISO study shows the new common interface definition affects real-time and day-ahead prices by less than $5/MWh in almost all cases, she added. The interface definition change is meant to eliminate overlapping congestion pricing incentives.

"The price incentive on June 1 shouldn't differentiate all that much," Li said.

The RTOs have made 23 successful day-ahead firm-flow entitlement exchanges since the exchange process began in January 2016. None of PJM's 15 requests or MISO's eight have been refused by the other RTO. (See "Regions Begin FFE Exchanges," *MISO/PJM Joint and Common Market Meeting Briefs*.)

SPP NEWS

SPS, SPP Ask Texas to Rule on Transmission Competition

By Tom Kleckner

Tolk Generating Station | *Xcel Energy*

Southwestern Public Service and SPP have asked Texas regulators to rule on whether Texas law includes a right of first refusal that overrides FERC Order 1000 (Docket No. 46901).

At issue is who will build a 90-mile, 345-kV line from Potter County to SPS' Tolk Generating Station in the Texas Panhandle. Without a state ROFR, the project would be open to competitive bidding under Order 1000.

SPS and SPP asked the Public Utility Commission of Texas to determine whether the RTO can designate entities other than the incumbent utility to construct and own regionally funded transmission facilities in Texas outside the ERCOT service area.

SPS contends in the Feb. 28 filing that the Public Utility Regulatory Act (PURA) allows it, as the incumbent utility operating outside ERCOT, the ROFR to build in the service area prescribed by the PUC. That would prevent a potential competitive project under Order 1000.

SPP says there is "no clear statement in Texas laws" that incumbent utilities have such a right, and it is following the Tariff's competitive bidding process until the commission "can resolve the issue as a matter of law."

The ruling will determine who gets to build the Potter-Tolk line — the only one of 14 projects in the Integrated Transmission Planning 10-Year Assessment not approved by SPP's Board of Directors and Members Committee in January. The board requested the project undergo further study and be brought back to its April meeting. (See "Board Sends $144M Tx Project Back for Re-evaluation," *SPP Board of Directors/ Members Committee Briefs*.)

SPS filed a lawsuit in a Texas state district court Jan. 18 seeking approval of its right to build the project and other 345-kV projects in its Texas service area. The utility also sought an injunction prohibiting SPP from issuing a notification-to-construct for the Potter-Tolk line to any company other than SPS.

However, the utility and SPP both agreed to temporarily suspend the lawsuit Feb. 27 and file with the PUC instead.

SPS spokesman Wes Reeves said the lawsuit against SPP and the subsequent PUC filing "are not … adversarial in nature."

"We simply seek clarity on our first right as a non-ERCOT utility to construct and operate regionally funded transmission lines within our service area," Reeves said.

In a statement, SPP General Counsel Paul Suskie said the two entities agree Texas law is unclear on ROFR issues.

"Our joint filing has been made with the intention of addressing that uncertainty," Suskie said.

In Order 1000, FERC explicitly acknowledged that it could not override state ROFRs. SPS contends PURA's legislative history confirms "transmission-only utilities are not permitted outside of ERCOT," and that any holder of a certificate of convenience and necessity must "serve every consumer in the utility's certificated area" and "provide continuous and adequate service in that area."

SPP asserted that because no local Texas laws or statues would be violated by its competitive bidding process, it would treat the Potter-Tolk line as a competitive upgrade and would seek bids for the project.

The parties proposed an intervention deadline of 30 days following the petition's publication in the *Texas Register*, set for March 17. Given the proposed schedule, it's all but certain there will be no resolution before SPP's April board meeting.

An administrative law judge gave the PUC until March 16 to file comments or make a recommendation.

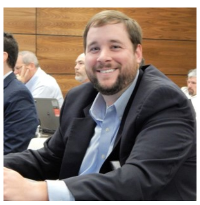
2017 ITP10 SPS North to South | *SPP*

SPP NEWS

Long Odds for 2nd MISO-SPP Joint Study

The odds of SPP and MISO conducting a second joint study dropped last week with the announcement that the RTOs' respective regional reviews are not lining up as expected.

The two RTOs had hoped to conduct a broad joint study starting as soon as this year that would evaluate regional and interregional projects on the same timeline, eliminating a major stakeholder complaint. (See *SPP-MISO IPSAC Turns Attention to 2017 Study*.) However, staff told the MISO-SPP Interregional Planning Stakeholder Advisory Committee on Thursday that their respective timelines are not lining up as expected.



Bell

"That created issues in scoping and planning. We hope to provide more detail and a schedule," Adam Bell, SPP's interregional coordinator, told the IPSAC. "We're both very committed to doing a study to the extent it makes sense. We're looking at what flexibility SPP has and what flexibility MISO has to work through the challenges this has presented."

Bell said MISO's Regional Transmission Overlay Study (RTOS), which will end in December 2019, is targeting the end of next year to determine transmission projects that can address the RTO's shifting resource mix. (See *MISO Begins 3-Year Tx Overlay Study*.) However, SPP's transition to its new Integrated Transmission Planning process won't result in the release of an economic study until October 2019.

Under the current timelines, MISO would spend 2019 building a business case around an approved portfolio. SPP is not scheduled to begin building its economic model until the third quarter of 2018.

"The timing is a little off in our ability to go through the process as we had originally envisioned," Bell said. "It looked like they would match up very well. We would have board approvals at the same time, do interregional work. … Jumping into something before we have all that worked out is not something we need to do."

Bell reassured stakeholders the two RTOs would still conduct "some sort" of joint planning in 2017 as part of their desire to take a more comprehensive look at reliability and economic transmission upgrades. He said staff would work with their regional stakeholder groups to resolve the misaligned timelines. A follow-up conference call has been tentatively scheduled for April 24.

"We all see the benefit of doing this broader study," Bell said. "We pretty much know when things will start and finish. We're trying to see now if there is any flexibility" in the timelines.

Several stakeholders were confused as to why staff had waited until the IPSAC meeting to bring the issue into the open. ITC Holdings' Marguerite Wagner pointed out one of the goals of SPP's new ITP process, which was approved last July, was to align it with MISO's timeline." (See "SPC, MOPC Approve Improvements to SPP's Tx Planning Process," *SPP Strategic Planning Committee Briefs*.)

"As far as I know, the SPP process has been developed for months," said the Wind Coalition's Steve Gaw. "I'm not sure why it's this meeting [that you discovered] you have an issue."

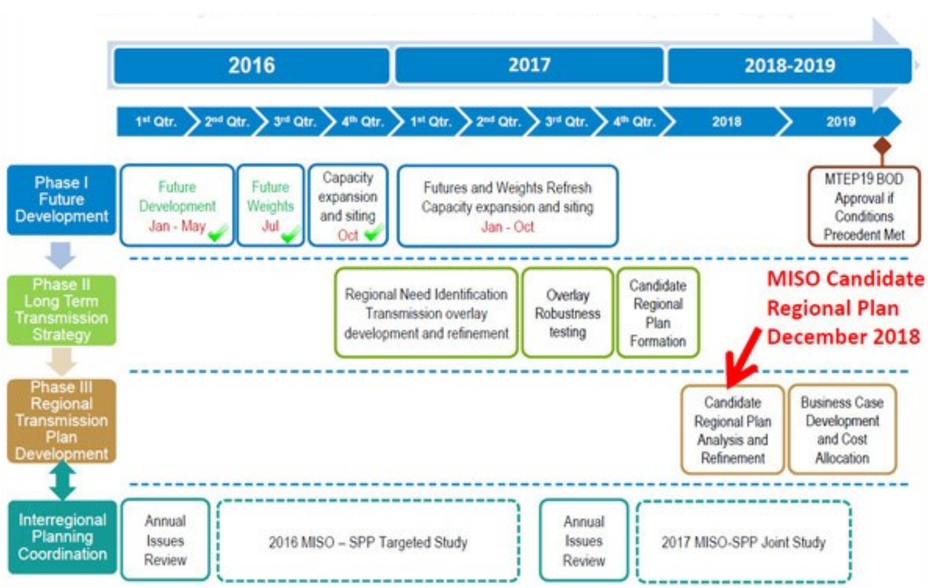
"We'll get back at the RTO regional level and work on the schedules a little bit," promised MISO Director of Planning Jeff Webb. "It's a good opportunity to get them back in alignment."

The IPSAC spent much of the meeting reviewing each RTO's planning processes and efforts being made to improve them. The first joint study between the two entities failed to produce a single interregional project; they have focused their efforts since on improving their coordination. (See *SPP, MISO Conclude Joint Study Empty-Handed*.)

"Someone smarter than me once said the definition of insanity is doing the same thing over and over and expecting different results," said Eric Thoms, MISO's manager of planning coordination and strategy. "We want to be more forward-thinking and understand why we are getting drastic differences in our interregional outcomes and studies."

As an example, MISO's Ling Lao detailed to stakeholders how the RTOs calculate the adjusted production cost (APC) differently for the Coordinated System Plan (CSP), a separate interregional effort from the joint study. The calculation is used for allocating costs between the two entities.

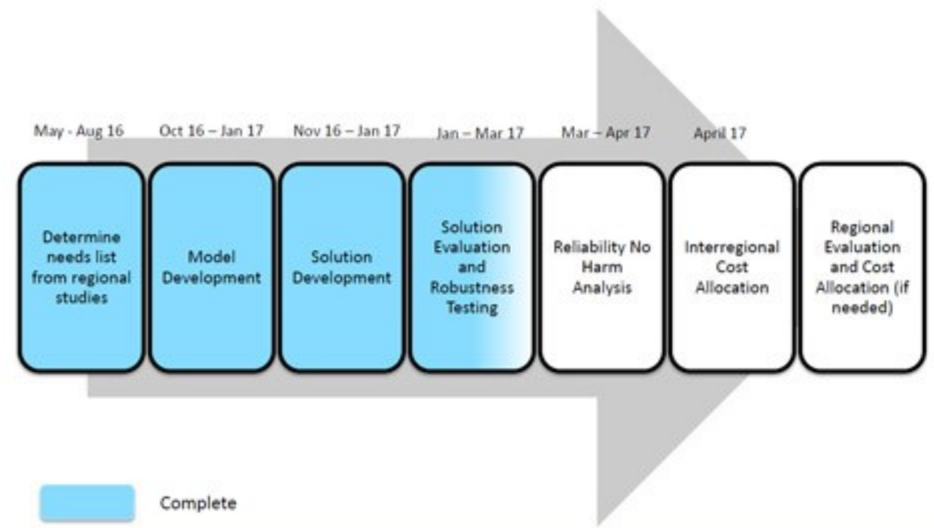
Lao said the MISO-SPP joint operating agreement outlines the APC-calculation methodology at a high level, similar to SPP's regional methodology. SPP uses the load LMP for pricing purchases and generation LMP for pricing sales. MISO, on the other



MISO RTOS timeline | *MISO, SPP*

Continued on page 45

SPP NEWS



MISO-SPP Coordinated System Plan process and timeline | *MISO, SPP*

Continued from page 44

hand, uses the generation LMP for pricing both purchases and sales in its metrics.

The load LMP is usually higher than the generation LMP when the system is congested, yielding higher project benefits or APC savings, Lao said. Thoms said MISO is currently evaluating changes to its APC calculation in its Regional Expansion Criteria & Benefits Working Group.

"Using different calculation methodologies introduces equity concerns," said SPP Director of Interregional Relations David Kelley. "It doesn't necessarily mean we know one method is better than the other. Could it be MISO is underestimating its benefits? Yes, but on the other side of the fence, you would say SPP is overestimating its benefits."

The APC was part of a screening process that has whittled the CSP's list of seven potential joint transmission projects down to three. (See "SPP-MISO IPSAC Turns Attention to 2017 Study, *SPP Briefs*.)

Staff said the three preliminary projects passing the study criteria are:

- A second 345/115-kV transformer in western Minnesota;
- A 161-kV line near Kansas City; and
- A 345-kV line and a 345/161-kV transformer near Springfield, Mo.

AECI Joint Projects Move Forward

The Springfield project would be in the same area where SPP's joint CSP with Associated Electric Cooperative Inc. identified two projects: a 50-MVAR reactor at Springfield's 345-kV Brookline substation, and a new 345/161-kV transformer at AECI's Morgan substation and an uprate of a related 161-kV line.

SPP's Seams Steering Committee took up both projects during its March 8 meeting. The Brookline reactor has an estimated cost of $1.1 million, below the $5 million minimum for SPP seams projects. However, staff said it sees a benefit in continuing forward with the project.

The SSC will meet again March 24 to discuss the project, in hopes of making a recommendation to the Markets and Operations Policy Committee in April.

The Morgan transformer was included in the 2017 ITP 10-Year assessment that was approved by the MOPC and SPP's Board of Directors in January. The project, valued at $9.2 million, is contingent on reaching a cost-allocation agreement with AECI.

SPP's monthly market-to-market report to the committee showed MISO sent another $250,762 in M2M payments to its seams partner in January, thanks to a net 230 hours of binding. SPP paid MISO just more than $51,000 for 126 hours binding over 11 temporary flowgates.

MISO has made $14.5 million in M2M payments since the RTOs began in the process in March 2015. When SPP completes two years of the M2M process in March, it will be at the same stage MISO and PJM were when they developed their targeted market efficiency projects on their seam.

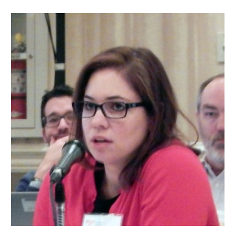
The projects address historical congestion issues on the MISO-PJM seam, and MISO and SPP said they are committed to following a similar approach later this year. The process focuses on small, low-cost, short-lead-time upgrades targeted at specific, historical congestion issues.

Z2 Task Force Narrowing its Alternatives

The Z2 Task Force met in Dallas on March 8 to review PJM and MISO's processes for incremental long-term congestion rights, which the group is considering as an alternative to its current crediting system for transmission upgrades. (See *SPP Z2 Task Force Looks for Best of Proposals*.)

The task force developed a list of alternatives for sponsored upgrades, transmission service upgrades and generation interconnections. ILTCRs remain a potential solution in each of the three categories, along with the existing Z2 processes, albeit with some modifications.

American Electric Power's Richard Ross and consultant Dennis Reed will also bring proposals to the group's next meeting. The task force plans to narrow down the list of proposals and then develop the details in order to meet a July deadline with the MOPC.



Buffington

"We're a task force," Kansas City Power & Light's Denise Buffington, the group's chair, reminded her team. "We can propose language, but we are going to address the policy question with the board first."

Buffington said it would be up to the board whether a task force or some other group drafts new policy language.

— Tom Kleckner

FERC NEWS

Supreme Court Refuses to Hear ROFR Challenge

By Amanda Durish Cook

The U.S. Supreme Court announced March 6 it would not hear a challenge seeking to reinstate the federal right of first refusal in transmission construction, letting an appellate ruling sustaining FERC Order 1000 stand.

In April, the 7th U.S. Circuit Court of Appeals in Chicago upheld Order 1000's removal of the federal ROFR in a challenge by Ameren and other MISO transmission owners (14-2153). The case was combined with two challenges by LSP Transmission Holdings that contended FERC did not go far enough in injecting competition into transmission development (14-2533, 15-1316).

The court ruled that FERC didn't have to show the federal ROFR was against the public interest before scrapping it. (See *Seventh Circuit Court Upholds FERC Order 1000 ROFR Provisions*.)

Ameren filed a petition for certiorari with the Supreme Court in October. The company, with Northern Indiana Public Service Co. and Otter Tail Power, argued that the April ruling is at odds with the *Mobile-Sierra* doctrine, and said FERC should assume the ROFR is reasonable unless the commission proves it is contrary to the public interest. The companies warned that failing to reverse the 7th Circuit's ruling would allow FERC to ignore the *Mobile-Sierra* presumption in the future.

FERC decided in 2011's Order 1000 that federal ROFRs that give incumbent transmission owners first pass on new project construction were anti-competitive and should be removed from all FERC-approved tariffs. Order 1000 did not, however, preempt state or local ROFRs.

"The *Mobile-Sierra* doctrine is based on the assumption that sophisticated parties with competing interests and equal bargaining power will usually reach a compromise that is reasonable and fair. The opposite is true when parties collude with one another to restrain competition and maintain a monopoly. … There is no reason to believe that a contract negotiated by parties with a shared interest in excluding third-party competition is similarly just and reasonable," FERC wrote in a brief to the Supreme Court in February.

MISO still honors state and local rights of first refusal and can use a limited federal ROFR for certain grid reliability projects. The RTO does not have a competitive project scheduled in 2017 because the year's lone market efficiency project — the $80.9 million Huntley-Wilmarth 345-kV line in Minnesota — is covered by the state's ROFR. (See *MISO Board Approves MTEP 16's $2.7B in Tx Projects*.)

FERC NEWS

Pipeline Foes Like Hobbled FERC Just the Way it is

By Michael Brooks


Fox

Glick


Henry


van Rossum

FERC's loss of its quorum has members of Congress and the natural gas industry feeling anxious, but anti-fracking activists said last week they will oppose any nominations to the commission in order to keep it paralyzed.

Ted Glick, a founder of Beyond Extreme Energy, said his group and more than 130 others were inspired to act when Chairman Norman Bay resigned Feb. 3 after President Trump named Cheryl LaFleur acting chair. Bay's departure left the commission with only two members, one short of the minimum needed to approve natural gas pipeline projects.

The commission approved seven natural gas pipelines worth 7 Bcfd before Bay left this year, according to the U.S. Energy Information Administration. The commission approved 17.6 Bcfd of capacity last year.

Besides lobbying senators to vote against nominees, the activists' efforts will include nonviolent civil disobedience, which his group has used to disrupt the commission's open meetings, Glick said during a news teleconference. (See *Meet the People Making Life for FERC a Little More Difficult this Week*.)

Beyond Extreme Energy and its allies see FERC as a rogue agency that ignores communities' input on pipeline projects and is cozy with the industry that it is supposed to regulate. Their opposition is nonpartisan, with the activists yesterday lambasting Democrats for their failure to rein the commission in.

"The appointment of one new commissioner could put that agency back in business and able to inflict incredible and irreparable harm on communities and our environment," said Maya van Rossum, leader of the Delaware Riverkeeper Network.

Preventing the restoration of FERC's quorum is virtually impossible, however. Republicans control the Senate 52-48, and Democrats can no longer filibuster the president's nominations except for the Supreme Court.

"The best outcome right now for the communities being abused by these pipeline projects and these pipeline companies and by FERC is to prevent" a quorum, and give Congress "the breathing room" to holding hearings "investigating the abuses that are happening at the hands of FERC, identifying the needed reforms and putting in place those reforms before a quorum is restored," van Rossum said. "We get that's a heavy lift. We totally get that."

Joining Glick and van Rossum on the call was Todd Larsen, executive co-director of Green America; Josh Fox, director of the Oscar-nominated documentary "Gasland;" and Maggie Henry, a former organic farmer. (See *Organic Farmer Turned Fracking Protester*.)

"It's not just that we will oppose the FERC nominees," Fox said. "Citizens all across this nation are gathering to build protest camps like the one at Dakota Access, and you will see a state of protest against fossil fuel infrastructure unlike anything we've ever seen in the United States of America."

Cantwell, Dems Urge 'Nonpartisanship'

Sen. Maria Cantwell (D-Wash.), ranking member of the Senate Energy and Natural Resources Committee, has other ideas.

She and 15 other Democrats wrote Trump the same day as the teleconference, urging him to respect the commission's tradition of nonpartisanship, noting that less than 2% of the orders issued in 2016 included a dissenting opinion. "We hope that your nominees will be prepared to continue this tradition, and we intend to review them through that lens during the confirmation process," the senators wrote.

They also said that both Republican and Democratic presidents have nominated people recommended by the Senate leader of the party that does not hold the presidency — Senate Minority Leader Chuck Schumer (D-N.Y.). "We expect you will honor this long-standing practice in nominating individuals to serve on the commission," the senators said.

COMPANY BRIEFS

Tesla Completes Solar-Battery Facility in Hawaii

Tesla has completed a solar project in Hawaii that can store energy during the day and dispatch it at night after the sun goes down.

The Kapaia installation includes a 13-MW solar system and 52 MWh of batteries. Tesla has a 20-year contract with the Kauai Island Utility Cooperative to deliver electricity at 13.9 cents/kWh, which is cheaper than the utility's cost for diesel of 15.48 cents.

The project is the largest of its kind to be placed in service by Tesla since it acquired SolarCity in November for $2 billion.

More: *Bloomberg*

Report: US Energy Storage Doubled in 2016

Led by a fourth quarter that marked a turning point in U.S. utility-scale energy storage, energy storage deployments in the U.S. totaled 336 MWh in 2016, doubling the megawatt-hours deployed in 2015, according to a report by GTM Research and the Energy Storage Association.

"U.S. Energy Storage Monitor 2016 Year in Review" found 230 MWh came online in the fourth quarter. That exceeds the combined total of the previous 12 quarters.

The report predicts the U.S. energy storage market will reach 7.3 GW in 2022 and will be valued at $3.3 billion.

More: *Greentech Media*

SoCalEd Seeks Distributed Energy Resources for Santa Barbara

Southern California Edison issued a request for offers (RFO) last week seeking distributed energy resources to help it prevent electricity outages in the Santa Barbara region.

The RFO calls for between 15 and 55 MW of storage, demand response, load shifting, and solar and fuel cells, which SCE needs to come online between 2018 and 2020.

The procurement addresses a localized transmission grid issue that SoCalEd discovered during its winter preparedness work in 2015 in which its analysis showed that heavy rainfall or other natural events could impact transmission towers serving the region.

More: *Greentech Media*

NV Energy Files for Approval of Rooftop Solar Alternative

NV Energy announced last week it has filed with Nevada regulators for approval of a renewable energy program that would provide an alternative to rooftop solar through state-based energy sources.

The Subscription Solar program would allow customers to subscribe monthly to at least 100-kWh blocks of solar energy, with the ability to purchase more blocks provided they do not exceed their monthly usage. The program would allow residential customers and, eventually, small- to mid-size businesses to meet up to 100% of their energy needs with renewable energy.

The company's Boulder Solar I facility has set aside 10 MW for the program. The Techren II facility, a joint venture with Apple, has set aside 5 MW and will be online by 2019.

More: *Reno Gazette-Journal*

PG&E to Repaint Tx Towers Coated with Lead-Based Paint

Pacific Gas and Electric plans to repaint about 6,000 electric transmission towers coated with lead-based paint beginning in April because of concerns over public health.

The project, which is expected to cost between $300 million and $400 million, will start in Fresno County, Calif.

The towers will be repainted with non-lead acrylic paint, with towers near schools, homes or parks receiving top priority.

More: *The Press Democrat*

Great Plains Relents; Asks Missouri Regulators' OK on Westar Deal

Great Plains Energy has complied with the Missouri Public Service Commission's order that it seek commission approval on its proposed acquisition of Westar Energy.

Great Plains, the parent of Kansas City Power and Light, relented Feb. 27 on filing the $12.2 billion sale with the regulators in response to the commission's Feb. 22 ruling on a complaint by the Midwest Energy Consumers Group.

The consumers group cited KCP&L's 2001 application to reorganize into a holding company (EM-2001-464). The restructuring — which created Great Plains as parent and KCP&L its subsidiary — contained an agreement that Great Plains would not attempt to merge with or acquire a public utility without first seeking commission approval.

The PSC had ordered Great Plains to file by March 4. Great Plains is asking that the commission render a decision before April 24 to keep the expected spring transaction closing date on schedule.

The commission said last year that it should have jurisdiction over the sale, but Great Plains said that the deal didn't require its approval because Westar is a Kansas company. (See *Great Plains Energy, Westar Shareholders OK $12.2B Deal*.)

Great Plains had argued that allowing the PSC in on the decision would "improperly expand the commission's jurisdiction to include the acquisition of non-Missouri regulated utilities by Missouri-based holding companies."

— Amanda Durish Cook

CenterPoint Mulling Midstream Stake, Sees Q4 Earnings Shortfall

By Tom Kleckner

CenterPoint Energy said it is continuing to evaluate an offer for its ownership share in Enable Midstream Partners, and it expects to "clarify" its position in the third quarter.

The Texas company has a 55.4% stake in the gas gathering and processing venture with Oklahoma City-based OGE Energy. CenterPoint is considering an offer to purchase its share, but it could also spin off the business or continue to manage its position.

"If we determine that neither a sale nor a spin would fulfill our criteria, our third path will be to maintain our stake in Enable and continue to support efforts to reduce exposure to commodity price influences," CenterPoint CEO Scott Prochazka said.

OGE made a second offer for CenterPoint's stake on Feb. 15 under its right of first offer (ROFO), along with an unnamed partner. CenterPoint, which rejected OGE's first offer in September, has until June 15 to make a final decision.

Prochazka said CenterPoint is continuing its "dialogue with interested parties" and it will "evaluate OGE's recent offer made pursuant to the ROFO terms of our partnership agreement."

"While the process is taking longer than originally anticipated, we expect to clarify which path we are on by the second-quarter earnings call," he said.

Prochazka's comments came during a Feb. 28 conference call with financial analysts following the company's fourth-quarter earnings announcement.

Q4 Earnings Fall Short

CenterPoint fell short of analysts' expectations, reporting fourth-quarter net income of $101 million ($0.23/share), compared to 2015's fourth-quarter loss of $509 million (-$1.18/share). Zack's consensus estimate was 29 cents/share.

The 2015 results included impairment charges totaling $984 million from its midstream investments. The company attributed the turnaround to rate increases and customer growth in its electric and gas utility businesses.

For the year, the company reported net income of $432 million ($1/share), compared to 2015's loss of $692 million ($1.61/share).

CenterPoint reiterated its 2017 guidance of $1.25 to $1.33/share.

The company's stock gained $1.99/share in the four days after the earnings announcement, ending the week at $27.90. CenterPoint shares have risen more than 13% since the beginning of the year — doubling the 6.4% increase in the Standard & Poor's 500 index — and are up 43% in the last 12 months.

Executive Appointments

On March 1, the company announced three executive appointments: Scott Doyle as senior vice president of natural gas distribution; Joe Vortherms, as senior vice president of CenterPoint Energy Services; and Jason Ryan, vice president of regulatory and government affairs. Doyle and Vortherms will report to Prochazka. Ryan will report to General Counsel Dana O'Brien.

AWEA: Wind to Grow 40% by 2020 Despite Loss of CPP

By Ted Caddell

U.S. wind industry jobs and generating capacity will grow by more than 40% by 2020, despite uncertainty over the Clean Power Plan, according to a study released last week by the American Wind Energy Association.

In fact, said AWEA CEO Tom Kiernan, President Trump's vow to undo the Obama administration's bid to cut power plant carbon emissions could be good news for the wind industry in the short run.

"If anything, [the death of the CPP] may accelerate" the pace of wind energy construction over the next few years, as projects attempt to beat the expiration of the production tax credit (PTC), Kiernan said.

Kiernan's comments came during a news conference Thursday at which AWEA presented a Navigant Consulting study that predicts that wind generators, who ended 2016 with 82 GW of nameplate capacity, will add another 35 GW by 2020.

Suzion S88 Wind Turbines at Dry Lake Wind Project in Arizona | *AWEA*

The study also predicts the number of Americans working for wind companies or in their supply chain will grow from the current 102,500 to 147,000. The number of direct wind energy jobs grew 17% in 2016, according to the study.

A two-thirds reduction in costs since 2009 has helped drive the industry's growth, AWEA said.

But some of the incentives the industry currently enjoys could be imperiled. The PTC, extended by Congress in 2015, will be phased out over three years, terminating at the end of 2019.

Tax credits drove a lot of the industry's success, Kiernan acknowledged. "The policy certainty provided by the 2015 production tax credit phase down has allowed the industry to make long-term investments in the American workforce and manufacturing to further bring costs down," he said.

Navigant said its projections were based on the assumption that the CPP, which also encouraged wind energy growth, would be stricken.

Energy Secretary Rick Perry oversaw a doubling of wind capacity in Texas when he was governor, but it's unclear how much he could do for the industry in his current role. (See related story, *Overheard at NECA Renewable Energy Conference*, p.18.)

Kiernan said land leases associated with wind projects will add up to about $1.2 billion in the next five years, benefiting farmers and ranch owners, making wind "a cash crop." The average land lease, for two turbines, comes out to about $6,000 a year.

FEDERAL BRIEFS

EPA Catches Vitriol After Pruitt Questions Climate Science

Pruitt

EPA logged about 300 calls and emails after Administrator Scott Pruitt questioned the link between human activity and climate change on the CNBC's "Squawk Box," a spokeswoman said.

On Friday, agency officials created an impromptu call center to deal with the deluge, and by Saturday morning the calls went straight to a full voice mailbox that did not accept messages.

A single comment on Reddit with the office phone number and a script suggesting what to say may have triggered the outpour.

More: *The Washington Post*

EPA Official Resigns, Urges Pruitt to Help Vulnerable Communities

The head of EPA's environmental justice program is stepping down, but not without using his resignation letter to urge Administrator Scott Pruitt not to extinguish the program.

Mustafa Ali, a senior adviser and assistant associate administrator at EPA, spent nearly 25 years at the agency working to alleviate the impact of air, water and industrial pollution on poverty-stricken communities.

Pruitt, who took office Feb. 17, is preparing to implement deep cuts in the agency's budget and staff. An internal memo obtained by multiple news outlets on March 1 called for a complete dismantling of the Office of Environmental Justice and eliminating a number of its grant programs.

More: *InsideClimate News*

Dems Try to Tie Coal Miner Pensions to Appointment

Several Senate Finance Committee Democrats last week tried to attach a bill to protect coal miners' pensions to a congressional waiver needed to move forward President Trump's nomination for U.S. trade representative.

Robert Lighthizer requires a waiver from the House of Representatives and Senate because he represented foreign governments in trade negotiations in 1985 and 1991. Committee Chairman Orrin Hatch (R-Utah) said Lighthizer's nomination should not be contingent upon completing the miner legislation.

Last week, 22,600 miners began receiving letters informing them that their health care benefits would be terminated at the end of April. It is their third notice in the past four months.

More: *The Hill*

Trump Considering 3 Nominees For FERC, Sources Say

President Trump plans to nominate Jones Day attorney Kevin McIntyre as chairman of FERC and Neil Chatterjee, senior energy adviser to Senate Majority Leader Mitch McConnell (R-Ky.), as commissioner, sources with knowledge of the situation told Bloomberg.

Additionally, Pennsylvania Public Utility

Continued on page 51

Federal Briefs

Continued from page 50

Commissioner Robert Powelson has been contacted by the administration about joining FERC. Powelson, who is also president of the National Association of Regulatory Utility Commissioners, confirmed that at an energy conference in Houston on Thursday.

According to the Jones Day website, McIntyre represents companies in cases involving energy markets, utility and oil and gas pipeline regulations. His areas of focus include compliance and enforcement, energy trading, competition issues and energy exports. As an architect of energy and environmental policy in the Senate, Chatterjee worked on the attack against the Obama administration's Clean Power Plan.

More: Bloomberg; The Wall Street Journal

Daniel Davis Named General Counsel of CFTC

Daniel J. Davis has been named general counsel of the Commodity Futures Trading Commission, the agency's acting chairman announced last week. He will assume his duties immediately.

Davis

Davis joins CFTC after serving as special counsel in the Labor and Employment Law Department of Proskauer Rose.

Earlier in his career, he practiced law at Gibson Dunn & Crutcher. From 2006 to 2007, Davis served as counsel to the assistant attorney general of the U.S. Department of Justice's Civil Division. He began his legal career as a law clerk for Judge Douglas H. Ginsburg of the D.C. Circuit Court of Appeals.

More: U.S. Commodity Futures Trading Commission

Senators to DOE: Protect Nuclear Whistleblowers

Three Democratic senators have signed a letter to Energy Secretary Rick Perry requesting he immediately reinstate rules allowing the department to hold contractors accountable for retaliation against whistleblowers who report nuclear safety violations.

According to the letter signed by Sens. Ron Wyden (Oregon), Claire McCaskill (Missouri) and Ed Markey (Massachusetts), final regulations establishing that retaliation against whistleblowers for raising nuclear safety concerns was a nuclear safety violation were issued on Dec. 27, 2016. In 2013, the department had stopped taking enforcement actions against contractors for whistleblower retaliation after finding its regulations did not allow it to do so.

With the incoming Trump administration, the department published a notice Jan. 31, 2017, that it was issuing a stay on implementation of the new rules.

More: Sen. Ron Wyden

State Briefs

CALIFORNIA

LA County Cites Quakes in Lawsuit To Keep Aliso Canyon Closed

Citing the threat of earthquakes, Los Angeles County sued state regulators last week to keep Aliso Canyon closed until the cause of its massive 100,000-metric-ton methane gas leak is identified.

The suit seeks a court order requiring the state Division of Oil, Gas and Geothermal Resources to conduct a public environmental review process, including preparation of an environmental impact report under the state's Environmental Quality Act, before allowing the Southern California Gas facility to reopen. It also alleges that oil and gas regulators prematurely concluded a safety investigation without addressing well safety and seismic risks.

The Los Angeles City Council recently adopted several measures to strengthen its oversight of SoCalGas. The measures were recommended following an audit of the city's franchise agreement with the utility after the gas leak.

More: Los Angeles Daily News; Los Angeles City Controller

County Takes Step to Bring Net Metering Back to IID

A motion approved unanimously last week by the Riverside County Board of Supervisors could bring net metering back to the Imperial Irrigation District after it was replaced with a less generous net billing compensation program in July 2016.

Under the motion, county staff will draft an ordinance that would require the district to offer net metering again in unincorporated parts of the eastern Coachella Valley. Supervisor Marion Ashley said there are Southern California Edison customers in Coachella Valley who enjoy net metering across the street from IID customers who cannot.

District officials said they did away with net metering to ensure solar customers pay their fair share to maintain the electric grid.

More: The Desert Sun

State Takes Lead in Battery Installations After Aliso Canyon

Spurred by the need to make up for anticipated electricity shortfalls stemming from the Aliso Canyon gas leak, state utilities led the way for installation of large-scale energy storage systems in the U.S. in 2016.

In 2016, 336 MWh of capacity were installed throughout the U.S. The majority of the installations took place in the state during the fourth quarter. As a result, the state, which has a goal to install 1.3 GW of batteries by 2020, has more energy storage capacity than any other region of the U.S.

Since 2010, developers have installed 643 MW of energy storage projects in the nation, according to Bloomberg New Energy Finance.

More: Bloomberg

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STATE BRIEFS

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Attorney General OK with Plans to Store San Onofre Nuclear Waste

The state attorney general is siding with Southern California Edison's plan to store nuclear waste in steel canisters encased in concrete at the shuttered San Onofre Nuclear Generating Station next to the Pacific Ocean.

Attorney General Xavier Becerra filed a brief this month asking a San Diego Superior Court judge not to set aside a Coastal Commission permit allowing 3.6 million pounds of nuclear waste to be stored behind a seawall. SoCalEd said the storage is temporary until another site can be found.

Activist group Citizens Oversight has sued to block the permit.

More: *KPBS*

MINNESOTA

Waseca Planning Commission Considers Solar Gardens

Waseca County could get three new 1-MW solar gardens under a proposal discussed by the Planning Commission at its March 2 meeting.

Innovative Power Solutions is presently working through issues relating to three proposed parcels for the project, two in Janesville Township and one in New Richland Township, that were chosen because of their physical characteristics as well as proximity to Xcel Energy infrastructure and landowner participation.

There is no set timetable as to when IPS will be moving forward before the county Board of Commissioners.

More: *Waseca County News*

NEW JERSEY

PSE&G Wants to Invest $74M in Energy Efficiency Initiatives

Public Service Electric and Gas filed a proposal with the Board of Public Utilities to invest $74 million to extend three energy efficiency programs and authorize two new initiatives.

The company is looking to extend its Hospital Efficiency Program, Residential Multifamily Housing Program and Direct Install Program. These programs support energy efficiency for hospitals and healthcare facilities, government facilities, nonprofit organizations, small businesses and residential multifamily buildings.

PSE&G is also seeking authorization for a Direct Install Program and a Smart Thermostat Program. The Direct Install Program would help government agencies, nonprofits and small businesses located in urban enterprise zones reduce their energy consumption and bills by paying for 70% of upgrade costs and by providing on-bill financing. The Smart Thermostat Program would provide a $150 discount for qualified thermostats.

More: *Public Service Electric and Gas*

NEW MEXICO

Regulator Disputes Research on Source of Methane Cloud

The state's top oil and natural gas regulator said a giant methane cloud hanging over the Southwest comes primarily from natural seeps in underground formations and coal mining operations, disputing findings by researchers with NASA's Jet Propulsion Laboratory and the California Institute of Technology.

"My personal opinion is that the methane hotspot in the San Juan-Four Corners area has existed for at least the last 10 million years," acting Energy, Minerals and Natural Resources Secretary Kenley McQueen said at a confirmation hearing last week.

In findings published last year in the *Proceedings of the National Academy of Sciences*, researchers traced the methane hot spot to sources including natural gas wells, storage tanks, pipelines and processing plants. They found only a small number of 250 methane sources were natural seeps from underground formations, and one was from a vent in a coal mine.

More: *The Associated Press*

OHIO

GOP Lawmakers Try Again to Get Rid of Renewable Energy Rules

Fresh off a veto by Gov. John Kasich in December, the Republican majority in the House of Representatives is once again trying to get rid of the state's renewable energy rules. This time they are attempting to do so with a bill that appears to take aim at American Electric Power's plans to build 900 MW of wind and solar and have customers pay for the construction.

Kasich

The bill, sponsored by Rep. Louis B. Blessing, would allow any customer who signed a contract with an independent power company to avoid paying the delivery company any extra charges for green power. It additionally would allow each power company to decide what percentage of the power they sell is generated by renewable technologies.

Under current law, by 2026, 12.5% of power sold must come from renewables. The proposed legislation would make the standards voluntary, and there would be no penalties for companies that chose not to sell green power. In 2026, the voluntary benchmarks would be removed from the law.

More: *Cleveland.com*

TEXAS

State Leads Way in Wind Energy Production

The oil-rich Lone Star State is the leading producer of wind energy in the U.S., exceeding production of the next three states combined, according to data from the American Wind Energy Association.

According to the association, the state has 20,321 MW of installed capacity. The next four top states are Iowa with 6,917 MW; Oklahoma with 6,645 MW; and California at 5,662 MW.

In 2005, Gov. Rick Perry signed into law a bill to build transmission lines connecting the state's windy plains to population centers like Houston, Austin, Dallas and San Antonio, which was paid for by ratepayers.

More: *NPR*

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Indiana Senate Moves to End Retail Net Metering

By Amanda Durish Cook

The Indiana Senate has approved a controversial bill that would phase out the state's retail net metering program.

State senators voted 39-9 to approve Senate Bill 309, which gradually lowers the payments residents receive for selling excess energy from their distributed resources back into the grid. The bill now proceeds to the state's House of Representatives.

Indiana residents currently earn the retail energy rate for their excess electricity, but the bill would reduce that compensation to 25% above the wholesale rate.

The bill originally contained a "buy-all, sell-all" provision that, if passed, meant homeowners would not have been able to use the power generated by their own solar or wind resources. Instead, they would have been required to sell all output to their local utility at wholesale, to be repurchased at retail. That provision was removed from the bill before the full Senate vote.

The bill underwent other amendments, including the addition of a grandfather clause — expiring in 2047 — for existing net metering customers and any residents who have equipment installed before July 1. Residents who sign up for net metering over the next five years would be covered under existing retail rate rules until 2032.

A provision that would altogether eliminate net metering by 2027 was also tossed from the bill.

The proposed law would also allow utilities to discontinue offering net metering in their service areas when net metering generation equals 1% of their peak summer demand load.

In a Feb. 22 opinion in Fort Wayne's *The Journal Gazette*, bill author Sen. Brandt Hershman (R) praised the legislation, calling it a "net gain for Hoosiers." The bill encourages "renewable energy generation while bringing more fairness and market sensibility to the way privately owned solar panels and wind turbines are subsidized by other customers," he wrote.

Hershman said that having electric utilities pay full retail rates for consumer-generated energy is unfair and that the prices are "two to three times the actual value of the energy on the market." Net metering was established to encourage investments in consumer-owned solar and wind generation when installation costs were higher, he contended, but the generation is now more affordable. He pointed out that the federal government has reduced its incentives for residential renewables.

The bill has found support from Indiana's major utilities, according to Mark Maassel, president of the Indiana Energy Association, which represents major Indiana electric utilities Duke Energy, American Electric Power's Indiana Michigan Power, Indianapolis Power and Light, Vectren and Northern Indiana Public Service Co.

"All Indiana's investor-owned utilities are working together on this," Maassel said. "The companies are very thankful for Senator Hershman."

Maassel said the utilities did not have a hand in authoring or revising the bill.

"The bill, where we ended up at, is a positive step and something we would like moved forward," Maassel said.

But solar and renewable advocates are not happy with the final product, arguing that the bill gives utilities too much control over residential solar and wind.

"Senator Hershman, Indiana's monopoly utilities and their friends in the legislature who are backing the bill say it was 'fixed' with amendments, but that's not true," said Wendy Bredhold, an Indiana-based representative of the Sierra Club's Beyond Coal campaign. "The utilities want to control solar power and take away Hoosiers' freedom to generate their own."

Bredhold called the bill a "step backwards" for Indiana and "energy freedom" and said that it "effectively kills homegrown, rooftop solar" in a state "controlled by powerful utility interests."

The Indiana Distributed Energy Alliance said the bill "will eviscerate net metering and customer-owned solar and small wind in Indiana."

Sean Gallagher, vice president of state affairs for Solar Energy Industries Association, said the bill's language fails to account for the full range benefits that residential generation can provide.

"Compensating … local power at average wholesale prices, as SB 309 proposes, significantly undervalues the benefits of producing that power — such as avoiding the need to build new power lines — and ignores the fact that solar power is produced during daytime peak periods when wholesale energy prices are higher," Gallagher said.

Gallagher has called on Indiana's legislature to let the Utility Regulatory Commission investigate the costs and benefits of rooftop solar before setting "arbitrary limits or determining compensation that customers would receive in statute."

STATE BRIEFS

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WEST VIRGINIA

FirstEnergy Files to Transfer Plant Between Subsidiaries

FirstEnergy subsidiaries Mon Power and Potomac Edison filed a request March 7 with the Public Service Commission to purchase the Pleasants Power Station from fellow subsidiary Allegheny Energy Supply for $195 million.

Moving the 1,300-MW plant out of Ohio's deregulated market and into the state's regulated market would lower rates and address an expected shortfall in the northern part of the state and the Eastern Panhandle, FirstEnergy said. It said its latest energy forecasts predict a capacity shortfall of more than 1,400 MW by 2027 for Mon Power.

Bids for the request for proposals were received Feb. 3 and were evaluated for cost factors that included expected customer impact, capacity availability, environmental considerations and acquisition costs, FirstEnergy CEO Charles Jones said in a conference call with investment analysts Feb. 22. Non-cost factors that were considered included the state's preference for in-state fuel sources, location and ease of integration, he said.

More: *The State Journal*