RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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Chatterjee Denies Lobbying Against FERC Nominee

By Rich Heidorn Jr.

WASHINGTON — FERC Chairman Neil Chatterjee on Thursday denied a report that he lobbied to block the nomination of Republican David Hill to the commission.

Citing interviews with a dozen industry and political sources who requested anonymity, E&E News *reported* April 12 that Chatterjee made calls to energy companies and Republican allies to block Hill from replacing him as chairman. E&E quoted Hill, an energy attorney who served in the George W. Bush administration, as confirming that the White House told him he would be appointed FERC chair.

Chatterjee did not respond to E&E's requests for comment before publication of the article. But in his regular news conference following the commission's monthly open meeting Thursday, Chatterjee attempted to discredit the report.

Hill was the Department of Energy's general counsel from 2005 until 2009 and NRG Energy's general counsel between 2012 and 2018.

E&E said Hill's nomination was all but official until lobbying efforts by Chatterjee, Energy Secretary Rick Perry and the coal industry caused the White House to abandon him. Hill had publicly criticized DOE's bids to provide subsidies for struggling coal and nuclear generators.

Chatterjee gave his rebuttal Thursday when

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Enviro Protesters Scale FERC HQ as Agency OKs More LNG

Ted Glick (left) and Drew Hudson broadcast from the top of FERC's awning via Facebook Live (p.9). | *Facebook*

FERC Orders Fast-start Rules for PJM, NYISO

By Michael Kuser, Christen Smith and Rich Heidorn Jr.

WASHINGTON — FERC on Thursday ordered PJM and NYISO to revise their tariffs to allow fast-start resources to set clearing prices, saying their current rules are not just and reasonable.

The order concludes investigations FERC began in December 2017 under Federal Power Act Section 206 and directs the grid operators to eliminate inflexible operating limits and other rules that the commission said are preventing prices from reflecting the marginal cost of serving load. (See *FERC Drops Fast-Start NOPR; Orders PJM, SPP, NYISO Changes*.)

"Fast-start resources are typically committed in real time, very close to the interval when needed, and can respond quickly to unforeseen system needs. But without some form of fast-start pricing, some fast-start resources are ineligible to set prices," the commission said in a *press release*.

FERC said the changes it is requiring will more accurately reflect marginal costs when the dispatch of a fast-start resource is the next action taken to meet load. It said the new rules will provide more accurate and transparent price signals to influence investment decisions, minimize production costs and reduce uplift.

"We find that commitment costs for fast-start resources are marginal because they are generally incurred in coordination with the real-time dispatch," the commission said.

FERC ordered NYISO to revise its pricing logic to reflect the start-up costs of fast-start resources and relax the economic minimum operating limits of all fast-start resources by up to 100% to allow them to set prices (*ER18-33*).

The commission gave PJM a longer list of changes, ordering it to make a compliance filing by July 31 (*EL18-34*).

In opening the investigations in 2017, the commission said MISO and ISO-NE have already implemented fast-start best practices and that CAISO would get limited benefit from

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In this week's issue

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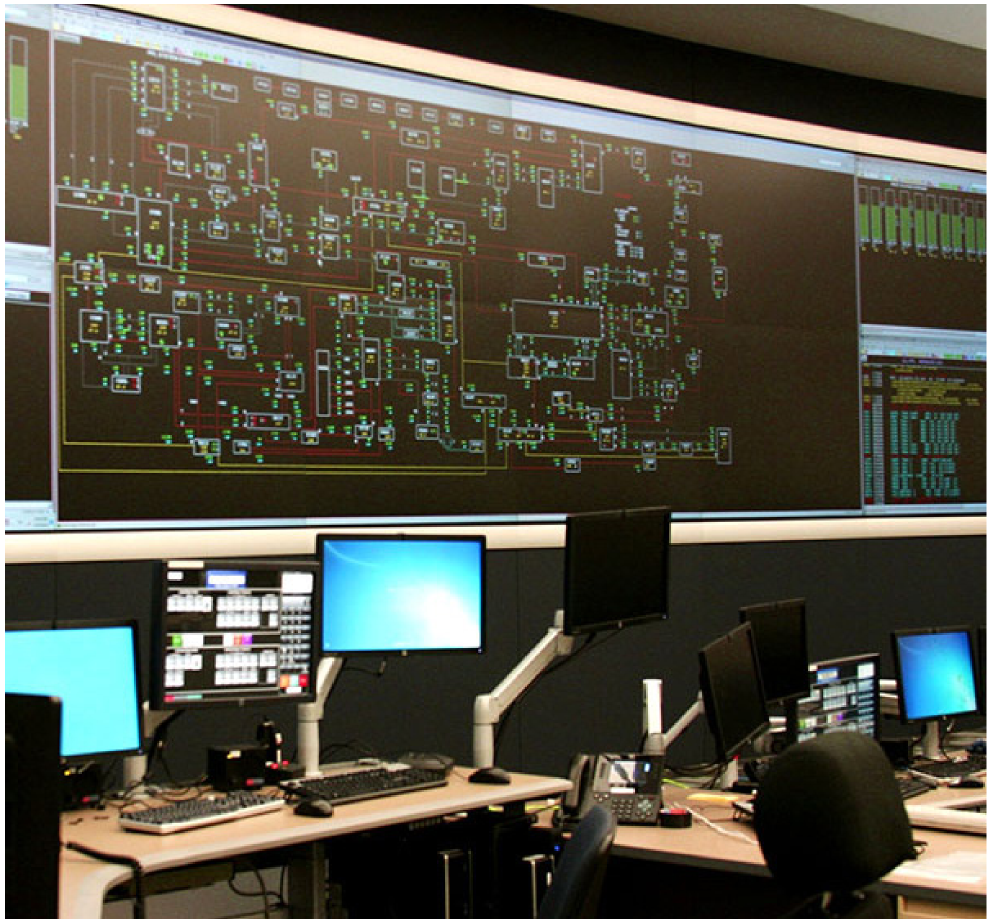
FERC Proposes Revisions to NERC CIP Standard

By Rich Heidorn Jr.



PPL's control room | *Barco Inc.*

FERC on Thursday proposed changes to NERC's draft critical infrastructure protection (CIP) standard addressing the cybersecurity of real-time communications between control centers.

The Notice of Proposed Rulemaking, which builds on a proposal by NERC, seeks comment on requiring the electric reliability organization to add protections on the availability of communication links and data communicated between control centers. It also sought comment on requiring NERC to clarify the types of data that must be protected (*RM18-20*).

NERC proposed standard CIP-012-1 in response to FERC Order 822 (*RM15-14*), issued in 2016. In addition to approving seven modified CIP standards, FERC's order directed NERC to require responsible entities to implement controls to protect communications links and sensitive data communicated between control centers. (See *FERC Postpones Action on Supply Chain Protections*.)

The order acknowledged that not all communication network components and data require the same level of protection because they pose different risks to bulk electric system reliability. As a result, NERC said its standards drafting team focused on the types of real-time data a control center will communicate and whether their compromise would pose a high risk to grid reliability.

NERC proposed exempting operational planning analysis data used in next-day operations, saying if there is a risk such data have been compromised, the responsible entity can verify the data prior to any impact on real-time operations. Although "an operational planning analysis factors into how an entity operates, there is less of a risk that an entity would act on compromised data from an operational planning analysis given it will base its operating actions on real-time inputs," NERC said.

Also exempt are oral communications, which are covered by standard COM-001-3.

'Largely Responsive'

NERC's proposed standard would apply to balancing authorities, generator operators, reliability coordinators, transmission operators and transmission owners that operate control centers. It would require them to identify security protections, where they are applied and the responsibilities of each entity for control centers owned or operated by different entities.

FERC's NOPR called NERC's proposal "largely responsive" to Order 822, saying it supports situational awareness and reliability by requiring rules to prevent the unauthorized disclosure or modification of real-time assessment and monitoring data transmitted between control centers.

But the commission said NERC's proposal may not address all cybersecurity risks, saying it does not require protections regarding the availability of communication links and data. The commission said it disagreed with NERC's contention that the issue of data availability is adequately covered by standards IRO-002-5 and TOP-001-4.

The commission said those two standards only require redundant and diversely routed data exchange infrastructure within control centers, not between them.

It also said the standard must be revised to add a definition of "real-time monitoring," which is not spelled out in the standard or the NERC Glossary.

FERC said NERC has "broadly defined" real-time assessments, which RCs and transmission operators must perform every 30 minutes to identify any actual or potential exceedances of system operating limits or interconnection reliability operating limits.

But it said "real-time monitoring is not defined at all."

"We are concerned that without further clarity, reliability standard CIP-012-1 may be implemented and enforced in an inconsistent manner," the commission said.

Comments on the NOPR are due 60 days from publication in the *Federal Register*. ■

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NERC Standards Committee Briefs

Comment Period Opens on Inverter Rules

The NERC Standards Committee on Wednesday unanimously approved the opening of a 45-day comment period on revised inverter rules in *reliability standard PRC-024*.

The standard authorization request (SAR) was prepared by the Inverter-Based Resource Performance Task Force (IRPTF), based on disturbance analyses and the development of the PRC-024-2 Gaps Whitepaper. The IRPTF identified potential modifications to PRC-024-2 to "ensure inverter-based generator owners, operators, developers and equipment manufacturers understand the intent of the standard." (See *NERC to Try Again on Inverter Rules*.)

NERC's D.C. offices | © *RTO Insider*

One of the most significant changes is in Section 4.1.2., where NERC proposes expanding applicability to include transmission owners "that own a bulk electric system generator step-up transformer or collector transformer."

It also requires inverters not trip or "enter momentary cessation" — an interruption in their injection of current into the grid — within the "no trip zone," except for "documented and communicated regulatory or equipment limitations."

Slight Change to Standards Efficiency Review Retirements

The standards drafting team for Project 2018-03 Standard Efficiency Review Retirements informed the committee of a need for a minor tweak to existing rules.

Reliability standard INT-009-2.1 Requirement R1 references standard INT 010-2, which has been selected for retirement. The team will remove references to INT 010-2 from the remaining standard to avoid confusion.

The drafting team arose from NERC's 2017 Standards Efficiency Review to consider the retirements of all or part of more than 30 reliability standards. (See "Team Gets Go Ahead on Standards Retirement Review" in *NERC Standards Committee Briefs: Jan. 23, 2019*.)

Standards Drafting Team Set for Response to FERC Order 851

The committee unanimously approved nine nominees for a standards drafting team to respond to the directives in FERC Order 851, which approved NERC's revised geomagnetic disturbance standard.

NERC created Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events) in response to FERC's directives to improve how its initial GMD standard, approved in 2016, addressed the risks from "locally enhanced" events.

Order 851, approved in November, directed NERC to revise the standard further to require the implementation of corrective action plans for responding to vulnerabilities to "supplemental" GMD events and to authorize case-by-case extensions of deadlines on corrective action plans. (See *Revised NERC GMD Standard Approved*.) ■

— *Christen Smith*

GULF COAST POWER ASSOCIATION'S ANNUAL SPRING CONFERENCE

GCPA Panelists Contemplate Balkanized Energy Policies

All (Energy) Politics is Local

By Michael Brooks

HOUSTON — The Gulf Coast Power Association's annual Spring Conference last week began the day after the U.S. Supreme Court declined to hear challenges to Illinois' and New York's zero-emission credit programs.

The court's decision was a stark reminder that individual states are driving changes to the country's electric generation mix, often to the frustration of the grid operators charged with operating competitive, economically efficient markets. (See *Supreme Court Won't Hear ZEC Challenges*.)

Doug Scott | © *RTO Insider*

"In the absence of a federal carbon-reduction system, states are taking a lot of actions on their own," Doug Scott, vice president of strategic initiatives for the Great Plains Institute, told the conference, which drew about 460 people to the Hilton Americas in downtown Houston. "Subsidies have been around in power generation, in virtually all forms of power generation, for a long, long time. So that's nothing new, but the way these are being applied now is something that is new."

Scott, who served in the Illinois House of Representatives and was later appointed chair of the Illinois Commerce Commission, noted that his state's ZEC program was less about reducing carbon emissions and more about preserving high-paying jobs at its nuclear plants. Current members of the commission have repeatedly expressed frustration with the PJM capacity market, currently in limbo as FERC labors on the RTO's proposed revisions to its minimum offer price rule to accommodate state-subsidized resources. (See related story, "PJM MOPR Issue 'Really Complicated,'" *FERC Open Meeting Briefs: April 18, 2019*.)

The Gulf Coast Power Association's annual Spring Conference this year was held at the Hilton Americas in Houston on April 16-17. | © *RTO Insider*

"I can really tell you that anything that a regional transmission organization does is not going to stop a state from doing what it thinks it needs to do to protect its citizens, to protect its businesses, to protect taxpayers and jobs," Scott said. "In fact, without disparaging my former colleagues, I would be willing to bet a lot of them don't know what PJM is and don't understand how the power markets actually operate."

The tensions between the states and grid operators are "only going to get worse" as states adopt increasingly aggressive renewable portfolio standards, he said. "We're going to need some kind of dialogue nationally about a coherent way to deal with all of the different measures that states want to take in the absence of any kind of federal policy."

The lack of national carbon policy also complicates interstate transmission, which many have said is needed to alleviate the oversupply of renewables in certain regions. (See "Hoecker, Demarest Propose Interstate Tx Siting Bill," *Overheard at Transmission Summit East 2019*.)

One might think that states seeking to procure more renewable resources would welcome high-voltage transmission projects to import from these regions. But SPP CEO Nick Brown poured cold water on that line of thinking.

"Here's the biggest issue: The folks east of us don't want our wind," said Brown, speaking during the conference's regular grid operator CEO panel. States want to develop renewables within their own borders, and "solar enables that to happen. ... So, I'd love to send our [extra wind] east, but ... as cheap as that might be, solar is changing the game because it is now so cheap and can be installed locally and ... improve local economies."

Left to right: SPP CEO Nick Brown, former FERC Chairman Pat Wood and ERCOT CEO Bill Magness. | © *RTO Insider*

On a separate panel discussing evolving RTO

GULF COAST POWER ASSOCIATION'S ANNUAL SPRING CONFERENCE

market designs, David Hunger, vice president of Charles River Associates' energy practice, noted that Western states began building renewable resources in response to California's demand. "But these states now are ramping up their own targets," he said. "So, wind power built in Wyoming, for example, is largely going to meet Wyoming state renewable standards."

Burcin Unel (left) and Jennifer Chen | © *RTO Insider*

Throughout the conference, GCPA ran an app that surveyed attendees while panel discussions took place. A poll during a panel on carbon pricing in wholesale markets found 77% of the audience in favor of the concept — a result that pleasantly surprised panel moderator Burcin Unel, energy policy director at the New York University School of Law's Institute for Policy Integrity.

"OK, that's exciting. Um, so, that was kind of unexpected for me," she said with a laugh.

But it's going to be a lot harder for a multi-state RTO to implement a carbon price than it is for single-state ISOs such as NYISO. PJM stakeholders will vote Thursday on whether to begin an initiative to consider carbon pricing in PJM's 13-state territory. (See *PJM Members Welcome Carbon Pricing Talks*.)

"These are political decisions as much as they are economic decisions or environmental decisions, and it's very difficult to get states to do something that may not be in their own best interests, the way they perceive it," Scott said. "It's very difficult to get unanimity from states that have generation mixes, different political climates, different histories, different utilities. I don't know a magic bullet for that; if there were, I think PJM would have found it already."

Sam Newell | © *RTO Insider*

"A big market like PJM ... is solving the optimization problem: the least-cost way to meet load given the costs of all the resources," said Sam Newell of The Brattle Group. "It's not a mathematically well specified problem to now try and do that optimization when there are multiple views on what the cost function is. So, there's no perfect answer." PJM could potentially "draw a loop" around a state that wants a carbon price and apply a hurdle rate, he said, but it would be complicated.

"Implementing a uniform carbon price would be very difficult" in PJM given all the different politics, agreed Jennifer Chen, senior counsel at Duke University's Nicholas Institute. She said that the RTO's software would need significant upgrades to account for different state prices.

"How well are the markets prepared in handling the challenges associated with the massive increase in renewables?" asked Judah Rose, executive director of ICF International and moderator of the market design panel.

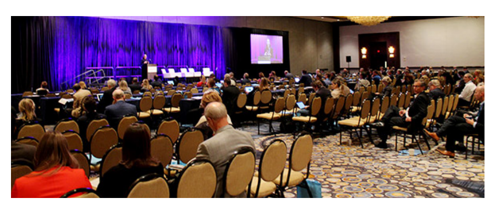
Adam Keech | © *RTO Insider*

"I think the broader issue is around multiperiod dispatch and pricing, and that's not something that I think is implemented anywhere, but I think it's a great discussion to have given where we're going," said Adam Keech, executive director of market operations at PJM. "Because the interest is not just how do we get from point A to point B in the next 10 minutes ... it's how I optimize that over the entire day.

"I think that's a broader discussion that's really not being had right now because technically that is a tough nut to crack. But ultimately I think that's the direction that we need to go."

"I think with renewables, the one thing everybody should be able to agree on is there are a lot of states and a lot of customers who want them," said Brett Kruse, Calpine's vice president of market design. "What's being mandated or set as a goal by a state or some other entity is being asked for by large customers. So it's incumbent on the system operators ... to figure out how to integrate this stuff and send the right market signals." ■

Left to right: Judah Rose, David Hunger and Brett Kruse. | © *RTO Insider*



Patricia Hoffman, deputy assistant secretary for the DOE Office of Electricity, addresses the conference.| © *RTO Insider*

FERC & Federal News

Chatterjee Denies Lobbying Against FERC Nominee

Continued from page 1

FERC Chairman Neil Chatterjee speaks to the press following the April 18 open meeting. | © *RTO Insider*

E&E reporter Rod Kukro, one of the authors of the article, asked him when he became aware that the White House intended to replace him with Hill.

Chatterjee challenged Kukro's premise, saying two other reporters had pursued the story and published nothing because they were unable to verify it.

"I know you cited 12 sources that you talked to. I know for a fact that at least two of those sources pushed back aggressively on the story line, yet their statements weren't reflected anywhere in the article. I also know that at least a couple of those sources directed you towards the actual people that were involved in this process and knew the details of it, and you ran the story without contacting the folks that were actually in the room and knew the circumstances of the story. You had no named sources. No corroboration."

Chatterjee challenged E&E's account that the White House and Hill began preliminary discussions in September 2018 about taking over for ailing Chairman Kevin McIntyre.

McIntyre, who was visibly unwell in his last commission meeting in July, relinquished the chairmanship to Chatterjee Oct. 24 after revealing that he had suffered a "serious setback" in his cancer fight.
He died Jan. 2.

David Hill | *LinkedIn*

"David Hill is a good man, and I find it almost impossible to believe that David Hill would have been negotiating in September to be chairman of the commission while Kevin McIntyre was still alive and serving," Chatterjee said.

"Well [Hill] was the source, and he was named in the story," Kukro shot back. "Are you saying he's lying that [National Economic Council Director] Larry Kudlow told him he was going to be chairman?"

"I can't speak for conversations you had with David Hill," Chatterjee responded. "I don't know that that's ever been corroborated by anybody."

RTO Insider asked the chairman why he did not respond prior to the article's publication.

"The story was so baseless that I didn't think it merited a response," Chatterjee said.

"So, you're saying you had no conversations with anyone regarding Hill's candidacy?" he was asked.

"No reporter has been able to identify a single individual that I contacted or what I talked about," Chatterjee said.

"That doesn't sound like a denial," the reporter said.

"That's a denial," Chatterjee said. ■

FERC & Federal News

FERC OKs Quicker Hydro License Process

By Rich Heidorn Jr.

FERC's Tara DiJohn (right) discusses the commission's hydropower rulemaking as colleague Shana Wiseman listens. | © *RTO Insider*

WASHINGTON — FERC on Thursday finalized a streamlined licensing process for hydropower projects at non-powered dams and closed-loop pumped storage projects, a response to a Congressional directive.

Under the new rule, the commission said it "will seek to ensure a final decision" within two years after receipt of a completed license application (Order 858, *RM19-6*).

Chairman Neil Chatterjee said the commission completed the rulemaking with three days to spare under the 180-day deadline set by Congress in the America's Water Infrastructure Act of 2018, which became law in October.

The expedited rules will apply to existing non-powered dams that are not already licensed or exempted from the licensing requirements of the Federal Power Act. The facilities must generate power through "withdrawals, diversions, releases or flows" from non-powered dams and must not make any material changes to the storage, release or flow operations of the dams.

Closed-loop pumped storage projects can qualify if they cause little or no change in existing surface and groundwater flows and uses and are unlikely to adversely affect threatened or endangered species. Reservoirs at natural waterways, lakes, wetlands and other natural surface water features would not qualify.

The rule permits only temporary withdrawals from surface waters or groundwater for the "initial fill and periodic recharge" of the storage facility.

Kentucky Dam and Lock 11 Hydropower Project | *Rye Development*

The rule requires developers to document their consultation with stakeholders, including tribes, dam owners and federal and state agencies responsible for required authorizations under the Clean Water Act, the Endangered Species Act and the National Historic Preservation Act.

Applicants for projects at a non-powered dam must prove the owner of the dam is not opposed to hydropower development. Projects using any park, recreation area or wildlife area created by state or local law must provide documentation that the managing entity is not opposed.

FERC said it issued the new rule after consulting with 28 federal agencies, state agencies and tribes, which participated in an interagency task force.

The new licensing option will be voluntary and will not change the commission's current three prefiling process choices for developers to use in preparing license applications.

"I hope that we have a large number of license applicants" under the new rule, Commissioner Cheryl LaFleur said. "There are approximately 80,000 unpowered dams in the United States. Many of them are probably not suited for power production, but some of them are and could be brought online to help contribute reliable, carbon-free flexible electricity."

The rule will take effect 90 days after publication in the *Federal Register*. ■

FERC & Federal News

Enviro Protesters Scale FERC HQ as Agency OKs More LNG

By Rich Heidorn Jr.

WASHINGTON — Anti-gas protester Ted Glick has been thrown out of FERC open meetings so many times that he's no longer allowed in.

So, on Thursday morning, he and fellow protester Drew Hudson climbed a large ladder and took up residence on the three-story awning over the building's main entrance, dropping a banner calling for renaming the agency the "Federal Renewable Energy Commission."

The protest was timed for the commission's monthly open meeting, at which the commissioners voted 3-1 to approve two additional LNG export projects. The meeting was interrupted twice by other members of the protest group, Beyond Extreme Energy, who were led out of the meeting room by security.

The protesters hung a banner seeking to rename FERC the "Federal Renewable Energy Commission." | *© RTO Insider*

Glick and Hudson broadcast their protest from the awning via Facebook Live, saying that LNG export projects will be rendered obsolete as the nation moves to 100% renewable energy to combat climate change.

FERC Chairman Neil Chatterjee said he sympathized with the protesters' climate concerns but that LNG exports provide net environmental benefits.

"This was a very big deal," he said after joining with fellow Republican Bernard McNamee and Democrat Cheryl LaFleur to approve the Driftwood (*CP17-117*, et. al.) and Port Arthur (*CP17-20*, *et. al.*) LNG projects and associated pipelines. Democrat Richard Glick — no relation to the protester — dissented.

The Driftwood project in Calcasieu Parish, La., will export an estimated 27.6 million metric tons of LNG annually, while the Port Arthur, Texas, project has a capacity of 13.5 million metric tons per year. There are currently 10 LNG export projects pending before the commission.

The U.S., which became a net exporter of natural gas in 2017, will see its role grow this year, FERC's Adam Bennett said during a presentation of the commission's annual *State of the Markets* report. "By the end of this year there should be six fully operational LNG export terminals here in the U.S.," he said. "This year alone, domestic export capability is likely to double."

Chatterjee said U.S. exports have "geopolitical" impacts, calling the LNG approvals "a very bad day for Russia," which has sought to use its natural gas exports as leverage over its European neighbors.

In a press conference after the meeting, Chatterjee said he respects the passion of the protesters, "particularly the folks who risked their physical safety to climb the building to make the point that they felt was important to make."

"I've been very vocal that I care deeply about climate change and the need to mitigate global emissions," he said, contending that U.S. LNG is "being used to displace dirtier sources of energy in other parts of the world."

"If people roll their eyes at me because I'm saying that the U.S. movement in LNG has … a positive impact on climate and carbon emissions, we're never going to be able to have a reasonable conversation here. I'm trying to be constructive. It is significant and is not something that should be dismissed."

A protester is ejected after interrupting the FERC meeting Thursday. | *© RTO Insider*

Chatterjee and McNamee have won LaFleur's votes on LNG projects since February by agreeing to include in the orders calculations of the direct greenhouse gas emissions from the liquefaction process.

But Chatterjee continued to reject calls by Commissioner Glick to quantify the downstream GHG impacts of such projects, saying it could leave the orders open to reversal. "I am not certain we have the capacity to do that. It could potentially jeopardize the orders in court," he said.

At the March commission meeting, Glick rejected Chatterjee's claim of a bipartisan "breakthrough" on the commission's evaluation of LNG projects, joining with LaFleur to say the panel was still ignoring the projects' impact on climate change. (See *Glick Disputes FERC 'Breakthrough' on LNG Projects*.)

Glick said the commission could require LNG exporters to mitigate their impacts on GHG emissions, as it does on environmental impacts on land, water and endangered species. "I think everyone knows what's going on here," the commissioner said. "This is climate change. That's why we can't talk about it."

LaFleur said she has included in her concurring opinions her own analysis of the projects' climate impacts as an alternative to dissenting.

"In spite of the fact that we have reached compromises on some language … it's getting harder, not easier, to do that," she said. "We treat climate change in our environmental analyses differently than every other environmental impact, and I think we're just waiting for the court to impose requirements on us that could add unnecessary complexities and legal risk to these very big projects." ■

FERC & Federal News

Record Gas Demand, Production Highlights FERC Markets Report

By Rich Heidorn Jr.

WASHINGTON — Record high natural gas demand and production highlighted FERC's 2018 State of the Markets *report*, released last week.

The report by the Division of Energy Market Oversight said gas demand was driven by electric generation and growing LNG exports. Despite big jumps in the Marcellus Shale and the Permian Basin regions, demand growth outpaced production increases.

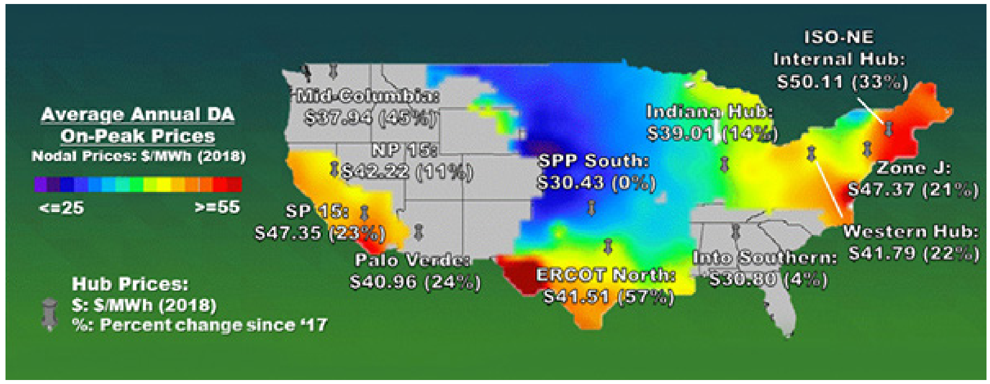
As a result, storage levels were lower than average and "at times were the lowest in more than a decade," FERC said, contributing to higher gas and power prices.

The Henry Hub benchmark averaged $3.12/MMBtu for the year, up 5% from 2017. Reduced storage inventories pushed Henry Hub prices up 31% in the fourth quarter over a year earlier.

Although gas prices remained relatively low, there was increased price volatility because of storage constraints, extended winter cold and infrastructure constraints in the West. In January 2018, an East Coast cold snap pushed gas prices to $140.85/MMBtu in New York and $128.39/MMBtu in the Mid-Atlantic, with prices peaking at $78.88/MMBtu in Boston. In contrast, New York's spot price never reached $21/MMBtu in 2017.

Gas production averaged 80.7 Bcfd, an increase of 12% from 2017. The Marcellus Shale was the most productive basin, averaging 19.4 Bcfd for 2018, up nearly 13.5% from 2017.

Haynesville Shale production jumped to an average of 6.5 Bcfd, a 46% increase that FERC attributed to higher gas prices and lower production costs. Rising crude oil prices were a factor in the 2.1-Bcfd increase in associated natural gas production in the Permian, a jump of 41%.



| FERC

More than 689 miles of commission-jurisdictional pipelines, representing 13 Bcfd of capacity, went into service during 2018, much of it connecting Marcellus and Utica supplies to markets in the Midwest, Northeast and Southeast. There was no capacity increase in New England.

Export Growth

New pipelines also provided links to LNG export terminals and exports to Mexico.

After becoming a net gas exporter for the first time in 60 years in 2017, U.S. net exports were almost 2 Bcfd in 2018, in part because of the opening of the Cove Point LNG facility in Maryland in March and the expansion of the Sabine Pass LNG terminal in Louisiana in October. LNG exports averaged nearly 3 Bcfd in 2018, a 50% jump from 2017.

Pipeline exports to Mexico rose almost 0.5 Bcfd to a new high of 4.6 Bcfd.

The report predicted up to 4 Bcfd of new export capacity will be added in 2019, with LNG facilities at Cameron, Corpus Christi, Elba Island and Freeport expected to go into service and an additional expansion at Sabine Pass. (See related story, *Enviro Protesters Scale FERC HQ as Agency OKs More LNG*.)

Power Prices Rise

As gas continued its increasing role in electric generation, fuel price increases also caused a jump in power prices across the country.

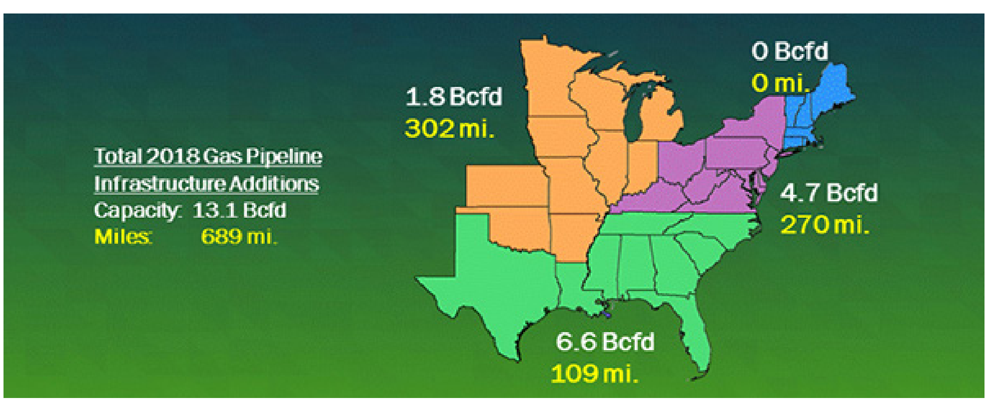
Mean day-ahead on-peak LMPs jumped almost 25% at RTO/ISO pricing nodes. Prices in SPP, MISO and CAISO increased less than 15%, while PJM and NYISO prices rose about 20%. ISO-NE was up 33% and ERCOT had the biggest jump at 44%.

As in recent years, most new generation capacity in 2018 was natural gas, wind and solar, and most retirements were from coal.

Capacity price trends varied in grid operators' 2018 auctions. RTO-wide average prices declined 13% in New England's auction for 2021/22, while the weighted average price in PJM's auction for the same period rose 36%.

In NYISO's spot capacity auction, prices in the high-cost Hudson Valley and New York City zones fell by 3% or more. Prices for Long Island rose 5% and the New York Control Area jumped 32%.

MISO's Planning Resource Auction saw zonal prices clear much lower than in the other markets with a price of 30 cents/kW-month for most of the region for 2018/19, up 25 cents from a year earlier. ■



| FERC

FERC & Federal News

FERC Open Meeting Briefs

Chief of Staff Named

FERC Chairman Neil Chatterjee on Thursday named veteran commission attorney Maria Farinella as chief of staff to replace Anthony Pugliese.

"Maria's longstanding career as an energy attorney, both at FERC for the past decade and in private practice, makes her uniquely qualified to fulfill this key role," Chatterjee said in a press release.

Farinella worked as a senior attorney in the Office of the General Counsel's Energy Markets Division from 2009 to 2011, and as a senior legal adviser in the general counsel's front office from 2011 to 2019. She was a legal adviser to Chairman Joseph T. Kelliher from 2007 to 2009. She is a graduate of Smith College and American University's Washington College of Law.

Pugliese, who abruptly left the commission March 15, had served as chief of staff since August 2017, before the arrival of Kevin McIntyre as chair in December of that year. He stirred controversy last July for remarks he made at a conference of the American Nuclear Society and on the "Breitbart Radio Show," in which he praised President Trump and criticized Democratic governors for blocking gas pipelines.

Chatterjee last month denied any conflict with Pugliese but declined to say why he had left. (See *Chatterjee Tight-lipped on Pugliese Departure*.)

Chatterjee: No Comment on NEPOOL Rules

At his regular press conference after Thursday's monthly meeting, Chatterjee declined to comment on whether he agreed with Commissioner Richard Glick's criticism of the New England Power Pool's policy of excluding the public and press from stakeholder meetings.

On April 10, the commission voted 3-0 to dismiss *RTO Insider*'s complaint under Federal Power Act Section 206 asking it to force NEPOOL to open its meetings or to strip it of its role as the stakeholder body for ISO-NE.

Chatterjee joined Glick and Commissioner Bernard McNamee in concluding FERC lacked jurisdiction to force such a rule change (*EL18-196*). Glick filed a concurrence, saying that while he agreed with his colleagues on the jurisdictional issue, NEPOOL's meeting policies are "misguided" and should be changed. (See *FERC Rejects RTO Insider Bid to Open NEPOOL*.)

New England is the only one of the seven U.S. regions served by RTOs or ISOs where the press and public are prohibited from attending stakeholder meetings.

Chatterjee declined Thursday to say whether he shared Glick's view that NEPOOL's meetings should be open. "I voted for the order. I think it speaks for itself," he said, declining to elaborate.

LaFleur: Not Leaving Yet


Cheryl LaFleur | © *RTO Insider*

Lame-duck Commissioner Cheryl LaFleur did not vote on the April 10 NEPOOL order or on an April 16 order regarding ISO-NE's energy efficiency rules. (See *FERC: ISO-NE Won't Change EE Rules Without Stakeholder Talks*.)

The recusals led to speculation that LaFleur — who announced Jan. 31 that she would not be appointed to a third term — has begun to search for her next job. Although her term ends June 30, she could serve the remainder of this year if no replacement is confirmed.

ClearView Energy Partners said such recusals are "common when a sitting commissioner is interviewing with an entity that may be involved in proceedings before the commission."

LaFleur, a New Englander, came to FERC after serving as executive vice president and acting CEO of National Grid USA.

LaFleur — who previously declined to give the reason for her recusal on the NEPOOL order — did not offer any clues to her plans at Thursday's meeting, where she introduced her son and husband in the audience.

"For the members of our friendly press corps, the fact that I have my family here does not mean this is my last meeting," she said, turning to reporters. "I will let you know when it's my last meeting. I promise."

PJM MOPR Issue 'Really Complicated'

Chatterjee said the commission hasn't yet acted on PJM's proposed changes to its capacity market because of the complexity of the issues.

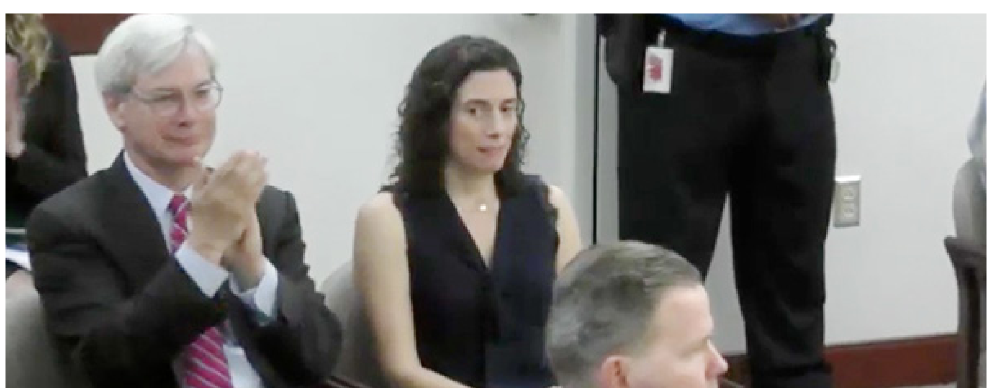
PJM, which normally holds its annual capacity auction in May, delayed it until August in the hopes that would give the commission time to rule on its proposed changes to its minimum offer price rule (MOPR). In June 2018, the commission ruled the RTO's existing MOPR was unjust and unreasonable because it didn't address price suppression from state subsidies for renewable and nuclear power. (See *PJM to Hold Capacity Auction in August*.)

Chatterjee was asked at his press conference whether FERC's failure to act on the proposal suggested a 2-2 split among the current commissioners and the need to fill its fifth seat.

The chairman said although he was prohibited from discussing internal deliberations, he could comment "at the macro level."

"When it comes to wholesale power markets, these aren't things that break down on ideological or political lines," he said. "It's just something my colleagues and I and staff are working towards. It is not something that we're gridlocked because of some kind of political difference. It's really, really, really complicated." ■

— Rich Heidorn Jr.


FERC attorney Maria Farinella receives applause after being announced as the commission's chief of staff. | *FERC*

FERC & Federal News

Sunrun Ruling Cuts Red Tape for PV Aggregators

By Robert Mullin

Rooftop solar aggregators scored a victory against paperwork Thursday when FERC issued a declaratory order exempting residential aggregations from certain filing requirements needed to obtain qualifying facility status under federal rules (*EL18-205*).

Residential solar company Sunrun last year petitioned the commission for two waivers related to QF certification under the Federal Power Act and the Public Utilities Holding Company Act.

The company — which has about 1,360 MW of PV capacity in 22 states and D.C. — does not currently make FERC-jurisdictional sales, but its petition signals it's headed in that direction.

In its initial *filing*, Sunrun explained that it intends to pursue "emerging" opportunities for aggregated distributed energy resources in organized electricity markets. It noted it has received "increasing inquiries from lenders and investors regarding QF status and the regulatory exemptions it affords."

But the company first needed to untangle some of the red tape that comes with operating QFs.

Under FERC regulations, a facility seeking QF certification must either file an application with the commission or submit a Form 556 for self-certification. QFs are also subject to the commission's "1-mile" rule, which holds that any small power production facility located within 1 mile of another small facility using the "same energy resource" and having the same owner will be considered one facility when calculating whether a facility exceeds the 80-MW cap on QF eligibility.

To relieve the regulatory burdens of the smallest operations, FERC's 2010 *Order 732* exempted facilities with net production capacities of 1 MW or less from both the filing and self-certification requirements. In its 2016 *SunE B9 Holdings LLC* decision, the commission adopted the use of the 1-mile rule for establishing whether a facility meets the 1-MW threshold.

Sunrun noted that most of its homeowner clients elect to have the company retain ownership of their PV systems, which, collectively, would be deemed owned by the same entity for the purposes of FERC's 1-mile rule. And while 99.5% of the company-owned systems

Sunrun scored a victory against paperwork when FERC issued a declaratory order exempting residential aggregations from certain filing requirements needed to obtain qualifying facility status under federal rules. | *FLS Solar*

have a nameplate capacity below 20 kW, the concentration of Sunrun's growth is such that it will not be able to rely on the 1-MW filing exemption in the future in certain regions.

"When the commission established the current rules for QF certification, it expressed a clear intention to keep residential PV systems free from the obligation of filing QF certifications," Sunrun said. "As a consequence, the QF certification requirements were not designed with residential-scale systems in mind."

Sunrun asked FERC to waive the 1 MW, 1-mile QF certification filing requirement for rooftop PV systems, contending its request was narrowly tailored to apply only to small (20 kW or less), separately interconnected, individual residential systems that homeowners have the option to purchase.

In granting Sunrun's request, FERC agreed the waiver "is not designed in a manner to circumvent the commission's regulations. Rather, the geographic concentration of residential PV systems financed by Sunrun, and the fact that individual homeowners make these location and financing decisions based solely on individual homeowners' personal preferences, create the need for the requested waiver."

The commission also said the facts in its *SunE B9* decision, which involved a large non-residential PV system with 18 500-kW inverters, were "distinguishable" from those in the Sunrun decision.

"Given the significantly larger number of individual residential PV system sites at issue here, however, and also the nature and size of these systems (i.e., residential systems with net capacities of 20 kW or less), as well as the fact that new residential customers may be added at any time and existing homeowners have the right to purchase the facilities subsequently, the administrative burden that Sunrun faces in order to remain in compliance with the commission's regulations would be significantly greater in comparison to the burden faced" in SunE B9, FERC said.

The commission also granted Sunrun's second requested waiver, so that when the company must submit a self-certification for systems greater than 20 kW, it is exempted from the requirement of including information related to systems 20 kW or less within 1 mile.

"The same reasoning that justifies the commission granting the first waiver request also supports granting the second waiver request," the commission said. "In particular, given the already substantial and growing number of PV systems of 20 kW or less in Sunrun's portfolio, coupled with the fact that new client homeowners are added frequently and existing client homeowners may at any time exercise their option to purchase their 20-or-less kW PV systems, the need to continuously update the Form No. 556 for these changes would place a significant burden on Sunrun and the commission without any obvious benefit." ■

CAISO/WECC News

Westerners Wrestle with Resource Adequacy, Grid Reliability

By Hudson Sangree

SALT LAKE CITY — Regulators and industry experts from across the West last week heard about cyberattacks and natural disasters, having enough renewable energy to meet demand, and the possibility of using compact nuclear reactors to backstop wind and solar.

The *spring joint meeting* of the Committee on Regional Electric Power Cooperation and the Western Interconnection Regional Advisory Body (CREPC-WIRAB) focused on grid reliability and protecting crucial infrastructure. The conference spread across three days, with roughly 16 hours of panel discussions and approximately 175 people in attendance.

It opened with a panel on small modular nuclear reactor power plants, in which NuScale Power showed its design for a 60-MW reactor that is far more compact than traditional nuclear units. NuScale is working with the Utah Associated Municipal Power Systems (UAMPS) and the Idaho National Laboratory (INL) to develop a working module by 2026. (See *With Big Nukes Dwindling, Supporters Focus on Modular*.)

The NuScale unit looks like a 75-foot-tall, 15-foot-wide torpedo. Twelve of the units could be combined to form a 720-MW power plant covering 35 acres, much less ground than is usual today, said Chris Colbert, NuScale's chief strategy officer.

"We've moved a number of components into the reactor pressure vessel, and what that allows us to do is to get rid of the piping and the pumps" that occupy much of the area in a traditional nuclear generating station, Colbert said. "When you go to a smaller design, you're able to eliminate over two-thirds of the systems and components you find a in a typical reactor."

That makes the unit simpler, with "less to operate it, less to maintain it and less things that can go wrong," he said.

Colbert and his fellow panelists acknowledged the public blowback that's likely to greet any proposal for a new nuclear plant.

"Obviously we've got a lot of risk here," UAMPS CEO Doug Hunter said.

The developers said they are planning to build the first generator at the Idaho National Laboratory, a nuclear research site larger than Delaware, with construction slated to start in 2023. They're hoping the isolated site and lots of public outreach "will allow a new generation of reactors to exist," said George Griffith, an INL relationship manager.

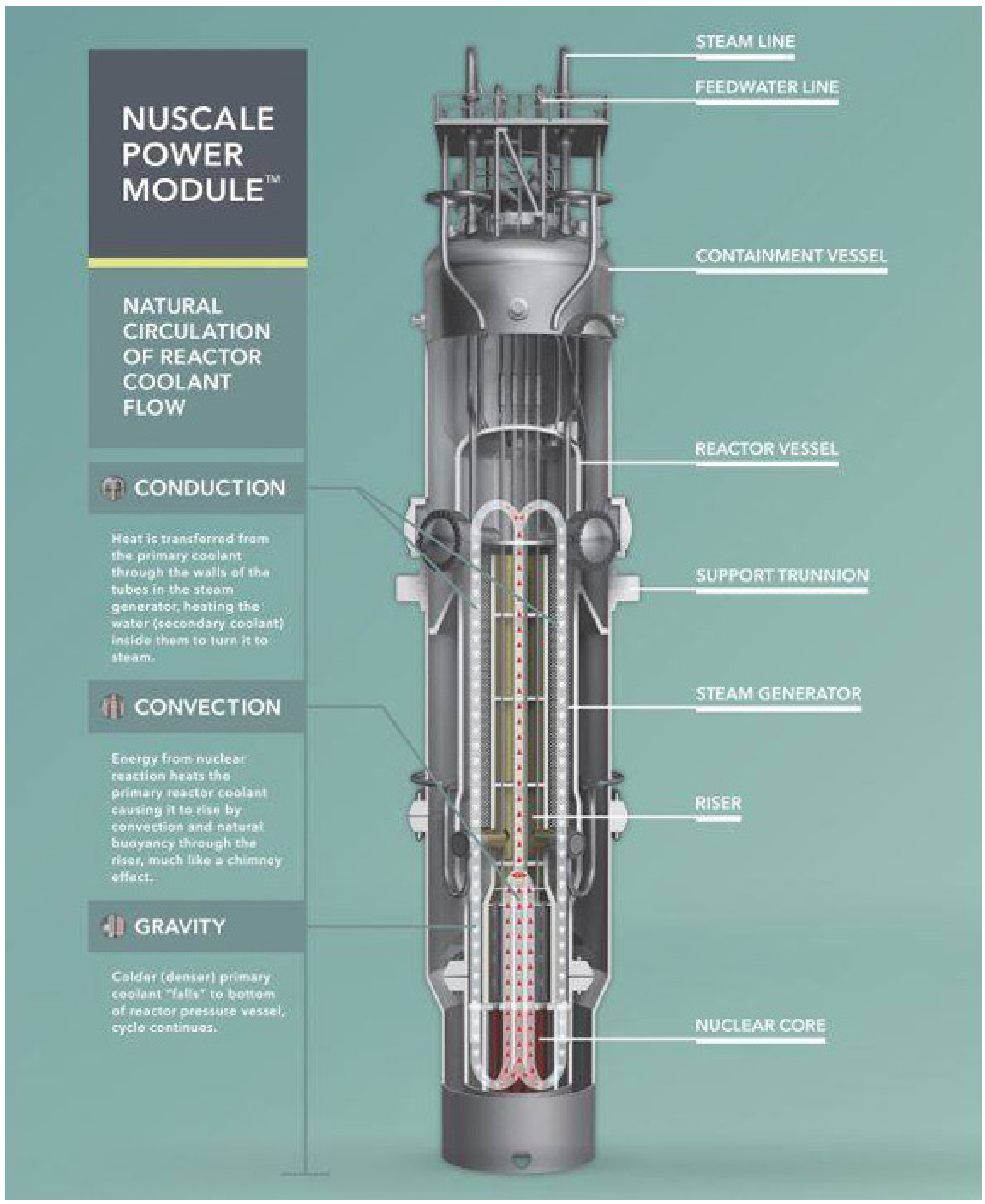
Colbert said the units will be needed to ensure reliability as older fossil-fuel generators are retired and a fast-growing number of states and cities establish carbon-free mandates. Wind, solar and hydroelectric may not be enough to keep the lights on because of varying weather and rainfall, he said.

"For those of you who've ever lost power for more than a day, you know what that can be like," Colbert said. "Imagine if it did it all the time."

Resource Adequacy Concerns

The same scenario was on the minds of state regulators and utility representatives who spoke at the meeting.

In a panel on Western resource adequacy and market purchases, Rick Link, vice president of resource planning and acquisition for Pacific Power, said diminished demand in the wake of the 2008 financial crisis had created surpluses



A compact nuclear unit designed by NuScale | *NuScale*

CAISO/WECC News

and made it relatively easy to depend on market purchases to supply needed power.

The thinking went, he said, that "it may be cheaper to do that, as long as [the power's] there, than spending $700 million to build a new gas facility."

But supply is tightening, and the situation is changing, he said. Those tasked with ensuring grid reliability can no longer just talk about economics and the best use of existing resources. Instead, they need to look at the development of new resources and innovative responses.

"It's great timing to have this discussion," Link said. "We may be transitioning into a period where we at least have to ask the question, 'Will [the electricity] be there?' So, it is more one of reliability, and that needs to be pushed front and center."

Panelists focused on the need for a regional entity to coordinate purchases and generation throughout the Western Interconnection and having sufficient transmission capacity. States will have to play a bigger role in regulation and coordination, they said. And utilities need to be able to share information about their activities to avoid conflicts, some contended.

Washington Utilities and Transportation Commissioner Ann Rendahl said regulators are concerned that utilities are overly reliant on market purchases, putting consumers at risk of rising prices in times of high demand and tight supply.

"What we don't know is whether [the utilities are] all basically relying on the same resources," Rendahl said. That would become clear in a cold snap or heat wave when supply tightens and prices shoot up, she and others said.

"There's increasing uncertainty that there is sufficient resource adequacy in the next five

State regulators who lead CREPC-WIRAB include (faces visible from left to right): Cliff Rechtschaffen, CPUC; Janea Scott, California Energy Commission; and Ann Rendahl, Wasington UTC. | © *RTO Insider*

years, creating an increasing possibility of a regional capacity condition" in the Pacific Northwest, Rendahl said. "Everyone is agreeing that we're approaching this point."

The "capacity surplus is quickly dwindling," she said, "and the utilities ... are not stepping forward to build capacity, leading to this very tight capacity market."

Disaster Readiness

Other panels at the meeting dealt with electric vehicles and the need to protect utility infrastructure from terrorist attacks. (See *Western EIM Looks to Expand Its Authority*.)

The discussion returned repeatedly to the theme of making sure the lights stay on.

During a presentation on the Initiative for Resilience in Energy Through Vehicles (iRev), panelists — including Laura Nelson, executive director of Utah Gov. Gary Herbert's Office of Energy, and David Terry, executive director of the National Association of State Energy Officials — discussed EVs in the context of catastrophes. EVs could allow evacuations in situations where gas is unavailable and could ensure emergency workers have vehicles that run, they said.

Most areas only have a week's worth of gas on hand at a given time, they said. Terry showed a photo of cars crowding a gas station after Superstorm Sandy in 2012.

Natural disasters such as Hurricane Katrina in 2005 and the 1989 Loma Prieta earthquake in the San Francisco Bay Area had shown the potential for the grid to go down for extended periods, said Doug Little, senior adviser in the U.S. Department of Energy's Office of Electricity.

"Imagine if you had to live for a week without electricity. It's pretty scary," Little said during his talk on protecting defense-critical electric infrastructure in the West.

"Katrina got pretty ugly" in New Orleans, and San Francisco lost power for several days after Loma Prieta, he said.

"Now we have to worry about destruction by terrorists that have become more and more resourceful," Little said. "We could see casualties and effects on security and economy from a cyberattack that would be comparable to weapons of mass destruction."

Russia, China and Iran represent potential cyber-terror threats, he said. (See *Senators Call for Urgency on Energy Cybersecurity*.)

The federal government's Advanced Research Projects Agency-Energy is investigating longer-duration battery storage to power the grid from 10 to 100 hours during disasters, Little said.

"If there was ever a time for megawatt-scale storage to be important, this is it," he said. ■

The CREPC-WIRAB spring meeting in Salt Lake City was well attended. | © *RTO Insider*

ERCOT News

Texas Public Utility Commission Briefs

PUC OK with Oncor-Sharyland-Sempra Deals

The Texas Public Utility Commission last week held off on giving its final blessing to $1.37 billion worth of transactions involving Oncor, Sharyland Utilities and Sempra Energy.

Handed a proposed order by Oncor the day before their Thursday meeting, the commissioners asked staff to bring a final order back to its May 9 meeting (Docket *48929*).

"I'm OK with going ahead and approving the settlement," said PUC Chair DeAnn Walker, drawing assent from her fellow commissioners.

The commission's final order will give Sempra a 50% stake in Sharyland Distribution & Transmission Services and Oncor ownership of Sharyland's transmission-owning InfraREIT. The asset exchange will increase Oncor's footprint in West Texas and "de-REIT" the Sharyland utility in South Texas. (See *Oncor-Sharyland-Sempra Deals Inch Toward Approval*.)

"We look forward to continuing the dialogue about the draft order," Oncor spokesman Geoff Bailey said. "We continue to believe that Oncor's proposed acquisition of InfraREIT is good for Texas, the ERCOT market and for Oncor."

Oncor to Pay $432K Penalty

The PUC's consent agenda included the approval of a settlement agreement between staff and Oncor that will result in the utility paying $432,000 in administrative penalties for 2017 feeder violations (Docket *48841*).

PUC commissioners confer with Stephen Journeay, director of commission advising and docket management.

Following an executive session, the commissioners also agreed to intervene in three FERC dockets:

- *ER19-1503*: MISO and Entergy Services' proposed revisions to Entergy operating companies' transmission formula rate templates.
- *EL19-62*: Springfield's (Mo.) complaint against SPP over its pricing zone costs as a result of the RTO's highway/byway allocation methodology. Springfield is asking FERC to "benefit-deficient zones," like Springfield's, from the methodology's "unintended consequences."
- *ER19-1541*: A proposed settlement agreement between MISO, its transmission owners and East Texas Electric Cooperative over the withdrawal and transfer of 38 MW of load and related assets from MISO to SPP ■.

— Tom Kleckner

April 24 TAC Canceled; OCN Workshop Set


TAC Vice Chair Diana Coleman and Chair Bob Helton | © *RTO Insider*

The ERCOT Technical Advisory Committee's leadership has canceled the committee's April 24 meeting because of a "limited number of items to be considered" and does not plan to hold an email vote.

Instead, ERCOT will use the date to hold a *workshop* on outage activity related to its operating condition notice (OCN) in late February. The OCN set in motion events that resulted in market complaints about the grid operator's communication practices and transparency. (See *ERCOT Generators Upset over Early March Weather Event*.)

The workshop will begin at 9:30 a.m. The TAC's next regularly scheduled meeting is May 22. ■

— Tom Kleckner

ISO-NE News

FERC: ISO-NE Won't Change EE Rules Without Stakeholder Talks

By Robert Mullin

Call it a false alarm.

In rejecting a request for a declaratory order last week, FERC provided the petitioners exactly what they were seeking: assurance that ISO-NE will not alter its energy efficiency performance standards outside the stakeholder process.

In February, Advanced Energy Economy (AEE) and the Sustainable FERC Project petitioned FERC to issue a declaratory order that would prevent ISO-NE from retroactively revising Forward Capacity Auction 13 qualification packages to include new measurement and verification (M&V) standards not previously applied to EE resources. They also asked FERC to clarify that the RTO must seek commission approval to make any such changes. (See *Groups Seek to Head off ISO-NE EE Changes*.)

In their initial *filing*, the groups said their petition arose from reports that ISO-NE staff had made a series of phone calls to Forward Capacity Market participants with qualified EE capacity resources. During those calls, staffers said the RTO intended to change how it measures the demand reduction value of EE resources for participation in the FCM.

The petition alleged the changes could include new "net-to-gross" conversion factors to revalue EE resources, meaning the resources could only offer into the FCM their net energy savings, rather than their gross reduction to load from baseline federal standards. The petitioners noted the factors were "never previously required of, nor imposed on, market participants," nor defined or described in the RTO's Tariff or manuals.

The groups contended ISO-NE staff indicated the RTO would potentially make the changes retroactively and without seeking commission or stakeholder approval, "even though the contemplated changes could significantly change the quantity of the resources that have already qualified for, and cleared, the most recent Forward Capacity Auction, FCA 13."

The petition garnered widespread support, including from public interest organizations, the Massachusetts attorney general and Eversource Energy, which asked that ISO-NE follow the New England Power Pool stakeholder process before making any changes.

FERC on April 16 dismissed the petition as "premature," citing ISO-NE's own statements in response to the petition and its lack of action on the issue (*EL19-43*).

"We find that the harm alleged in the petition is speculative in light of ISO-NE's clarification that it has not made any proposal, nor does it currently have any plans, to change its M&V standards," the commission wrote. "Furthermore … because ISO-NE has not proposed a change to its M&V standards, there is no concrete proposal for the commission to evaluate to determine whether a Tariff filing is required. As such, there is no controversy or uncertainty necessitating a declaratory finding at this time."

ISO-NE said it was all a misunderstanding.

"As the script used by an ISO staff member for calls to energy efficiency providers makes clear … the ISO was informing energy efficiency providers that it is in the process of evaluating the implication of potential changes in federal energy efficiency standards and new information regarding net-to-gross savings ratios," the RTO said in its March 7 initial *response* to the petition. "The communications do not reflect that the ISO was proposing a practice change or intending to make one."

The RTO said it was evaluating current M&V practices because expected changes in lighting efficiency standards under Section 321 of the Energy Independence and Security Act of 2007 "could substantially affect the baseline against which the savings from efficient lighting programs are determined."

It also cited "a growing disparity between gross savings and net savings values for energy efficiency resources" reflected in updated state studies on the performance of energy efficiency measures.

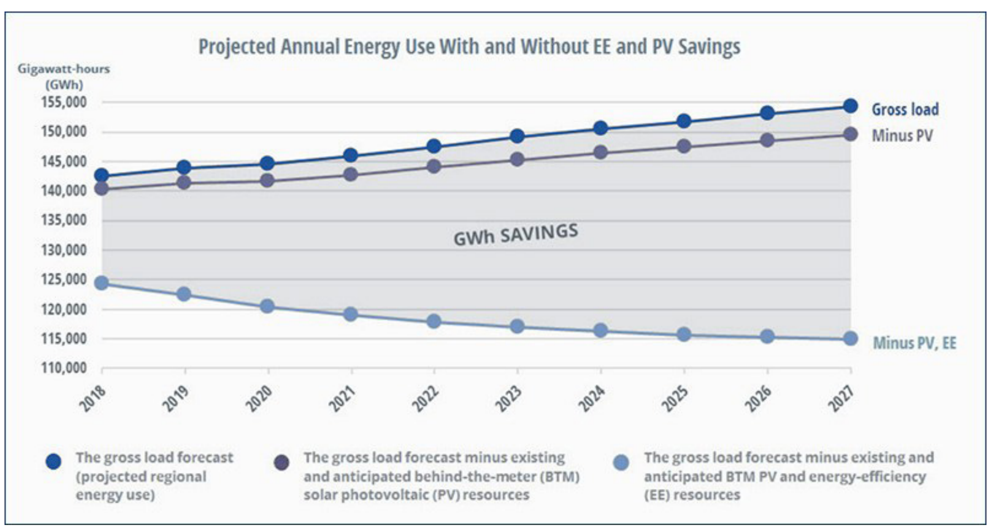
"These factors warrant evaluating current practices regarding the measurement of energy savings for energy efficiency resources to assess whether changes to the ISO's measurement standards are appropriate," ISO-NE said.

But it said any changes would require modifications to ISO-NE manuals or Tariff and would be done "only after any such changes are vetted through the stakeholder process and any Tariff changes are filed and accepted by the commission."

The commission's order included comments reassuring to the petitioners. "In particular, in its second answer [to the petition], ISO-NE committed that it would only implement a gross-to-net savings methodology for determining the capacity value of energy efficiency resources through a Section 205 filing."

AEE said it was happy with the outcome.

"As the commission states in its order, ISO New England has committed that it will not make changes to the measurement and verification standards for energy efficiency resources without engaging stakeholders and making a filing with FERC," Jeff Dennis, AEE managing director, said in a statement. "We appreciate this commitment by ISO-NE in its answer to our petition, and the commission's recognition of it, which brings needed clarity and certainty for energy efficiency resource providers." ■

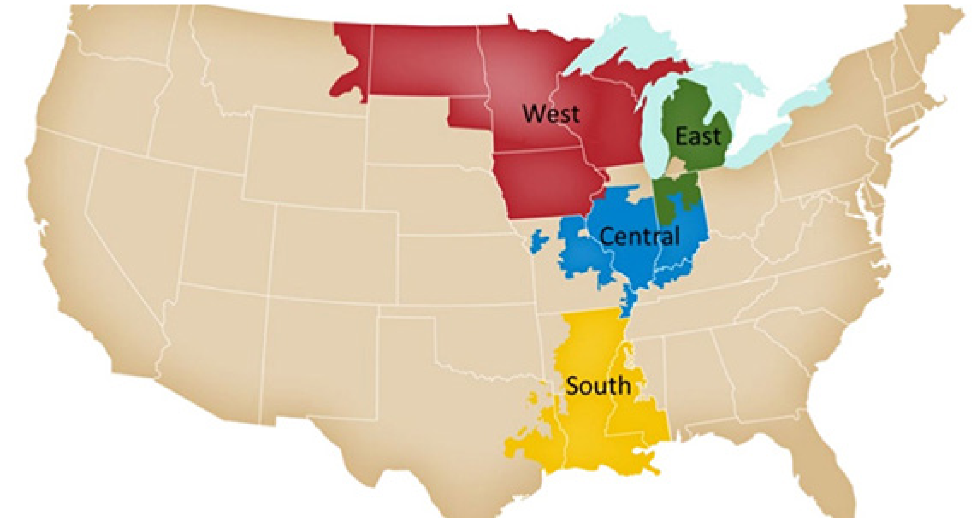


Graph shows New England's projected energy savings from energy efficiency projects. | *ISO-NE*

MISO News

MISO Takes 2nd Look at North-South Constraint

By Amanda Durish Cook



MISO footprint | *MISO*

MISO will take another crack at identifying a project that could provide an alternative to the constrained transmission path linking its North and South regions.

In its previous attempt to uncover an economic alternative to its transmission use agreement with SPP for the North-South interface, MISO couldn't find a solution that could pass the 1.25-to-1 benefit-cost criteria based on adjusted production cost benefits. (See "No Tx Coming for North-South Constraint," *MTEP 17 Proposal: 343 New Transmission Projects at $2.6B*.)

But staff now have the "bandwidth" to take on the *effort* as part of this year's market congestion planning study, MISO Planning Manager Matt Ellis told the Planning Advisory Committee on April 16. The study is designed to identify congestion-relieving projects that provide economic benefits exceeding the costs stemming from congested flowgates.

Ellis said MISO's motivation to find possible solutions stems from both its research into showing that renewable growth is set to increase flows on the contract path, and the uncertainty around future terms and costs of its settlement agreement with SPP.

He said the RTO will reuse some underlying data from its 2017 footprint diversity study, which was exclusively aimed at finding a solution to alleviate the contract path. He said the lack of solutions from that effort isn't deterring staff, pointing out that there are two years of fresh data on the contract path to study now.

"This is classic transmission planning. Many times, we look at the same flowgate multiple years in a row. The idea is 'Hey, it's a been a few years; let's see what's changed,'" Ellis said.

Beginning this Thursday, MISO will open a second, special project submission window for the market congestion planning study. Project submissions will be limited to solutions that physically cross the North-South interface and terminate on either side in MISO territory. Solutions must either eliminate or reduce settlement costs, or increase MISO's regional transfer capability.

MISO will test project candidates against a scenario based on the possibility that the terms of its agreement with SPP continue in perpetuity. Ellis said MISO will also consider a sensitivity where the agreement is terminated and flows are again limited to the original 1,000-MW contract path. The agreement currently limits MISO line flows to 3,000 MW north-to-south and 2,500 MW south-to-north.

Ellis said MISO will likely develop a more specific list of design requirements. All project ideas will be due June 21.

While MISO intends to produce project recommendations by late August, Ellis stressed the research will be thoughtful and methodical. "Throughout this process, if we feel that we're rushed … we have the flexibility to push back the timeline [and] add meetings. We're not bound by an MTEP 19 decision point in this study." ■

MISO News

MISO Planning Subcommittee Briefs

MISO Examining New Benefit Metrics

MISO and its stakeholders are considering how to more accurately measure the potential benefits of proposed transmission projects.

The RTO is in the process of "refreshing" an ongoing *list* of possible new benefit metrics, planning adviser Adam Solomon said during a Planning Subcommittee meeting April 16.

MISO last year created two new metrics to help size up the benefits from market efficiency project candidates: the value of deferred or avoided reliability transmission projects resulting from an MEP, and the value of increased capacity on the contract path connecting its Midwest and South regions.

The RTO said it may develop even more benefit metrics by the end of the year, including increased capacity import and export limits, reduced congestion from fewer transmission outages, reduced transmission losses and whether projects can boost grid resilience. (See "More Benefit Metrics?" *MISO MEP Cost Allocation Plan Goes to FERC*.)

In 2017, MISO and stakeholders participating in the Regional Expansion Criteria and Benefits Working Group (RECBWG) created a "high potential" list of possible benefits that included the transmission losses and resilience metrics, as well as reduction of capacity costs from reduced peak load losses and the value of future capacity expansion deferral from increased capacity import/export limits.

Stakeholders asked MISO to elaborate on how it plans to measure the benefits of added resilience.

"We were hoping you would actually," Solomon joked, noting the RTO is seeking stakeholder input on the metric.

"Resilience seems so vague and broad … you would almost have to create a separate stakeholder process to [define it]. I would just hate to see this bog down the process when you have other, specific and quantifiable ideas," said Sam Gomberg, senior energy analyst with the Union of Concerned Scientists.

Solomon said he would return to the RECBWG with an updated list of benefit ideas stakeholders want to explore. MISO and stakeholders will work on prioritizing the list in the middle of the year, then discuss the feasibility of the selected benefit metrics in the third quarter. He asked stakeholders to submit written comments on the issue by May 17.

Release of 2nd Tx Cost Estimate Guide

MISO and stakeholders are finalizing the second-ever version of a cost estimation *guide* for the RTO's 2019 Transmission Expansion Plan.

The RTO released its first cost estimation guide for market efficiency or multi-value projects early last year with the intent of updating the estimates as appropriate. (See *MISO Releases Transmission Cost Estimates Guide*.)

MISO divides transmission costs into four categories: land and right of way; structures and foundations; conductor, optical ground wire and shield wire; and professional services and overhead. Substation cost estimates are the sum of land and site work; equipment and foundations; protection and control; and professional services and overhead.

This year, MISO has added estimates for wooden poles as a structure type and for removing existing transmission lines.

But the cost estimates will be limited to traditional transmission construction components. The guide does not include estimates for HVDC lines and burgeoning technology such as energy storage-as-transmission, design engineer Alex Monn said.

"More specialized and customized project ideas are challenging to generalize for the purposes of a cost estimation guide. MISO will consider these project types on a per project basis," the RTO said.

"From our research … those projects are really customized and site-specific, so you won't find those in our cost estimate guide," Monn said. ■

— Amanda Durish Cook

Adam Solomon | © *RTO Insider*

MISO News

MISO PAC Contemplates SATA Shakeup

By Amanda Durish Cook

The MISO Planning Advisory Committee will vote by email on a DTE Energy proposal to broaden the scope of the RTO's effort to create new rules allowing storage projects to solve transmission needs.

DTE's *motion* proposes that stakeholders and the PAC recommend that MISO include a path for non-transmission owners as well as TOs to own and operate storage-as-transmission assets (SATA). The motion will appear on an email ballot April 22-26.

In developing the rules, MISO determined that only registered TOs should be eligible to own SATA in order to avoid introducing complexities around cost recovery, particularly related to how non-TOs would be compensated for providing transmission services.

DTE says non-TO SATA should be permitted to bypass the interconnection queue and connect to MISO's transmission system via newly conceived storage interconnection agreements.

To be eligible to secure a storage interconnection agreement, DTE proposes that resources must resolve a transmission-reliability issue identified in the annual Transmission Expansion Plan (MTEP) process, "satisfy the same performance criteria" as other SATA in the MTEP analyses, and "be operated strictly at the direction of MISO's transmission-reliability function to address such issues."

MISO's Carmel, Ind., control room | *MISO*

DTE's Nick Griffin said the motion will close an "equity gap" in MISO's first SATA filing with FERC. Absent DTE's provision, he said, the SATA ruleset would create preferential treatment for TOs and "create barriers for entry for storage."

Griffin said the motion does not yet address cost recovery.

In a complicated interpretation of MISO's stakeholder process, the Steering Committee last month directed the PAC to revisit the possibility of non-TOs owning SATA in response to DTE's request. (See *MISO Planning Committee to Reconsider Non-TO Storage as Tx*.) Some stakeholders were concerned that PAC leadership prematurely suppressed conversation on DTE's proposals by not holding a vote to gauge whether stakeholders thought the idea warranted further debate.

MISO has said stakeholders agreed before drafting the SATA rules that they would neither address non-transmission alternatives (NTAs) nor create an entirely new cost allocation as a part of the SATA policy development.

But MISO Director of Planning Jeff Webb said the RTO's existing *process* to consider NTAs in transmission planning may cover what DTE seeks.

Jeff Webb | © *RTO Insider*

"As a general matter, we do not require non-transmission alternatives to complete the generator interconnection process unless the asset is a generation facility seeking access to the market," Webb explained.

Not that Simple, Stakeholders Say

Entergy's Yarrow Etheredge pointed out there is no structure in place for MISO to assume functional control over assets other than transmission. She said DTE's proposal wasn't as simple as minor Business Practices Manual or Tariff changes.

Great River Energy's Jared Alholinna agreed that DTE's motion would create a "gray area" around what is and isn't transmission and could ultimately undermine the FERC definition of transmission.

"This is being characterized as quite narrow, but it really balloons out," American Transmission Co.'s Bob McKee said.

Griffin said non-TO SATA could have similar treatment to a generator under a system support resource agreement, in which MISO dictates that assets be available for dispatch.

"We think with a few minor BPM and Tariff changes, we could achieve analogous treatment," Griffin said.

But Etheredge said an SSR-style treatment still lacks the automatic controls that MISO has established with its TOs.

Xcel Energy's Drew Siebenaler said the motion could create the discriminatory treatment DTE claims to combat because the proposal names a special interconnection path meant only for storage devices.

"I would view that as a discriminatory filing," Siebenaler said.

DTE coming forward without a defined cost allocation was problematic as well, added Xcel's Carolyn Wetterlin. She said she had never heard of a MISO project gaining approval without first having an established cost allocation method.

MISO's Environmental sector took the discussion as an opportunity to call out the SATA proposal as too limiting in the first place. Clean Grid Alliance's Natalie McIntire said the current plan ignores the full spectrum of storage capabilities. She said MISO has rushed the first SATA proposal and "unreasonably" limited the scope of a possibly "precedent-setting" ruleset.

Webb acknowledged that MISO's "first stage" SATA rules are intentionally narrow so that storage doesn't have to scale the approximate three-year interconnection queue before being eligible to solve a transmission need.

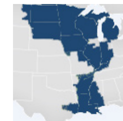
"We wanted to clear that barrier first," he said.

Webb promised MISO stakeholders future Tariff proposals that would allow expanded and multifaceted storage use in the footprint.

The PAC will hold a May 15 conference call to discuss refinement of the SATA filing and announce the ballot results on DTE's motion.

MISO hopes to file the new rules with FERC in June or July. One SATA project is currently moving through MTEP 19 in the hopes that rules are in place by the end of the year. ■

MISO News



MISO Previews Abridged MTEP Report

By Amanda Durish Cook

MISO is considering moving ahead with a plan to streamline its report detailing the projects in its annual Transmission Expansion Plan (MTEP) beginning with this year's.

Project Manager Sandy Boegeman on Wednesday told MISO's Planning Advisory Committee that the RTO is considering *removing* brief histories of previous MTEPs, some descriptions of regional studies, an introduction to the resource adequacy construct, and descriptions of MTEP futures development and independent load forecasting.

Last month, MISO said it planned to reconfigure the MTEP report to emphasize the justifications and analyses behind the list of proposed projects while condensing planning process narratives. The RTO aims to create a more concise and readable report, which typically runs about 200 pages and always includes descriptions of the studies and processes used to recommend projects. (See *MISO Considering Slimmed-down MTEP Report*.)

MISO hopes the new format will help guide the RTO's Board of Directors in its deliberations over project approvals, Boegeman said.

Jesse Moser, MISO director of economic and policy planning, said the RTO is also examining the accessibility and usability of the planning *section* of its website to ensure that information removed from the report is easier to locate online. He said the web improvements could take a few years to complete.

"We're trying to do this in a way that retains what's important," Moser said.

Veriquest Group's Dave Harlan said that removing futures development information from the report may inadvertently weaken its rationale for some transmission projects.

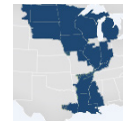
"To just sort of poke around on the website … is a burden that's going to frustrate everyone," Harlan said. He asked MISO to create a "definitive" appendix of website links in the report supporting the necessity of the projects in the plan.

Moser said he and his team would consider the idea and asked for additional stakeholder feedback by May 3.

Jesse Moser | © *RTO Insider*

PAC Chair Cynthia Crane urged stakeholders to think about what pieces of the report are essential and which should be memorialized. The PAC is scheduled to vote on whether to recommend the MTEP 19 report at its Oct. 16 meeting. ■

MISO News



More Time Needed for Storage Compliance, MISO Says

By Amanda Durish Cook

CARMEL, Ind. — MISO will ask for at least another year to comply with FERC Order 841, saying the intricacy and expense of incorporating storage into its markets is greater than it originally anticipated.

MISO leaders say the original Dec. 3 go-live date to comply with the order is no longer feasible given FERC's recent deficiency letter in response to the RTO's proposed storage participation model. MISO was counting on the commission accepting its filing this month to maintain a strict timeline for adapting its market to storage participation.

FERC earlier this month issued separate deficiency letters to all six jurisdictional RTOs and ISOs regarding their plans for energy storage participation. (See ***FERC Asks RTOs for more Details on Storage Rules***.) The commission specifically asked MISO for several more details and explanations related to its phased participation approach, proposed commitment statuses, complexities for distribution system storage resources, conflicting offers and bids, and make-whole payments. The RTO has until early May to respond.

Kevin Vannoy | *© RTO Insider*

MISO Director of Market Design Kevin Vannoy said the combination of a later-than-anticipated FERC order, remaining uncertainty about what the commission will decide after the RTO's response and holding work on software changes because of that uncertainty led to the request.

"In our response to this request, we are going to ask for a deferral," Vannoy told the Energy Storage Task Force on Thursday.

Vannoy said the deferral would be "no earlier than a number of months after a clean order." When pressed, he said the RTO could request for 12 to 18 months from when FERC fully accepts its filing.

The "cost and complexity" of implementing new bid parameters for storage was greater than MISO predicted in 2018, Vannoy said. Work also remains on how energy storage operators will communicate data to the RTO, he added.

MISO is in the process of answering FERC's multiple questions in the 10-page deficiency letter, he said.

"We didn't see anything in there one way or the other that they were leaning towards rejecting or accepting the filing. We think they simply need more explanation," Vannoy said of the commission's tone in the letter.

FERC also asked MISO to explain a provision that prohibits distribution-level storage resources from pseudo-tying into a different balancing authority. Vannoy said RTO leadership feels that pseudo-tying storage is beyond the scope of the final rule.

MISO had warned stakeholders in mid-April that it was anticipating a "significant delay" in developing a functioning model for storage participation.

During an April 11 Market Subcommittee meeting, Vannoy said MISO staff have been discussing the deficiency letters with other RTOs. He said MISO is limited by what its legacy market platform can handle as it's gradually swapped out for a new cloud-based market platform. MISO Senior IT Director Curtis Reister said the RTO is targeting a complete replacement of the platform by 2024, and rolling out a new market user interface — the site market participants use to submit bids and offers — in mid-2021. (See ***MISO Seeking Multiple Vendors for Market Platform Redesign***.)

The Energy Storage Task Force meanwhile is set to sunset in June. Task force Chair John Fernandes said that through next month, the group will create a spreadsheet of storage issues that other stakeholder groups can concentrate on, focusing heavily on how the RTO will integrate hybrid resources that contain storage assets. ■

MISO NEWS

Renewables Outlook to Get Boost in MTEP 20 Futures

By Amanda Durish Cook

After prodding by stakeholders, MISO now says it will boost renewable generation estimates in each of the four 15-year future scenarios that guide its annual transmission planning process.

MISO had previously proposed relying on an older set of futures to inform the 2020 Transmission Expansion Plan (MTEP 20). But stakeholder pushback prompted the RTO to *increase* the minimum renewable penetration levels for each future by 5%, bumping projections from 15-35% of the generation mix to 20-40%.

Speaking at a Planning Advisory Committee meeting Wednesday, MISO Planning Manager Tony Hunziker noted the high degree of consensus among stakeholders to increase renewable estimates.

The MTEP will also assume the solar investment tax credit — which allows a 30% federal tax deduction of installation costs — will continue into 2023. The RTO will also rely on the National Renewable Energy Laboratory's *Annual Technology Baseline* capital cost projections for renewable generation instead of using a 30% variance on those projections.

However, some stakeholders said they'd like to see a more nuanced approach to projecting renewable growth based on subregional characteristics to avoid blindly increasing renewable projections. For instance, MISO shouldn't expect significant wind generation growth in sunny MISO South, some noted.

"MISO is not a resource planner. We don't dictate renewable resource additions," Hunziker responded.

Entergy's Yarrow Etheredge said MISO didn't adequately support the case for a blanket increase of every type of renewable generation everywhere in its footprint.

"This is basically just an adder," Etheredge said, asking MISO to defend the change using data.

Hunziker promised a complete rework of MTEP 21 futures with stakeholders and reminded PAC members that MISO was up against a June deadline to finalize MTEP 20 futures definitions and assumptions.

The RTO last month said it would rely on the same set of 15-year futures for the third straight year to evaluate transmission projects in MTEP 20, though some stakeholders criticized the RTO's limited fleet change future as no longer a likely scenario. (See *MISO Going Back to the Futures for MTEP 20*.) The futures scenarios include a limited fleet change, continued fleet change, accelerated fleet change, and a distributed and emerging technologies future.

Hunziker said the renewable increase should alleviate specific concerns about MISO's limited fleet change future, which has been criticized as improbable because it projects only an 11-GW growth in renewable generation through 2033. MISO's interconnection queue currently includes about 420 projects worth a combined 70 GW; renewable resources account for about 90% of the queue. Historically, about 18% of proposed projects clear the queue.

Last month, members of MISO's Board of Directors also questioned whether the limited fleet change future was still plausible.

"It seems like the rate of adoption is increasing," Director Thomas Rainwater said, while also acknowledging that MISO is "no California" in terms of appetite for renewables. He asked if the RTO will consider "a more radical adoption" of renewables and distributed resources in a new set of futures for MTEP 21.

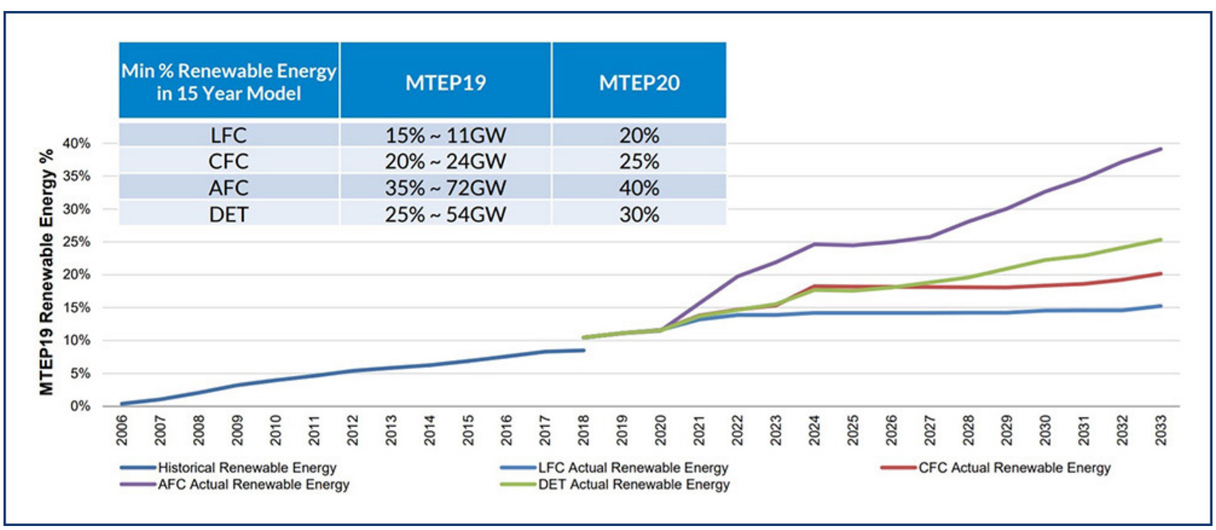
MISO Vice President of System Planning Jennifer Curran said the accelerated fleet change and distributed and emerging technologies scenario are fast becoming the most probable futures and noted the RTO will soon revisit how futures are developed. But she also cautioned that MTEP futures represent possible trends and are not meant to be forecasts.

At the April PAC meeting, Minnesota Public Utilities Commission staff member Hwikwom Ham said he remained concerned that the limited fleet change and continued fleet change scenarios still risk obsolescence because they don't account for the zero-carbon pledges of multiple utilities and increasing electrification of the economy. He also pointed out that equity investors are now contemplating a company's carbon footprint as a risk factor before making investments decisions.

"Who is going to be in the White House next year? It's going to be a different business model," Ham added, referencing President Trump's rollbacks of environmental regulations.

Hunziker said MISO will raise those topics in the redevelopment of futures in time for MTEP 21.

Meanwhile, MTEP 20 marks the first time MISO will work with Purdue University's State Utility Forecasting Group and Applied Energy Group to create separate load forecasts that reflect each of the four futures. The RTO this month reported that entities representing 77% of its load responded to its request for load, demand and energy data. ■



Increased renewable projections in MTEP 2020 futures | *MISO*

NYISO News

NYPSC Refines Value Stack, Boosts Community DG

Utilities Assessed $3.9M in Storm Response Settlement

By Michael Kuser

Sean Mullany (left) and Christian Bonvin

The New York Public Service Commission on Thursday modified its value of distributed energy resources (VDER) compensation policy and authorized $43 million in state funding for solar and other community distributed generation projects in the Hudson River Valley and New York City (*15-E-0751*).

The commission's *order* refines the compensation rules it set in 2017. "The decisions in this order improve the predictability, transparency and accuracy of DRV [demand reduction value], locational system relief value (LSRV), and capacity value calculation and compensation," the commission said.

The order directs utilities to file tariff revisions within 20 days, to be effective June 1.

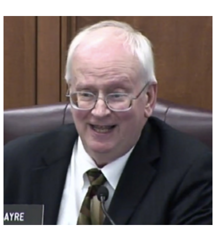
It also noted inconsistencies in utilities' marginal cost of service studies and initiated a proceeding to "determine what methodologies will lead to the most accurate results" (*19-E-0283*).

The new rules incorporate, with modifications, most of the recommendations commission staff made in two white papers in December. (See *NY Examines VDER Capacity Value Compensation*.)

In a white paper on compensation, staff said that the current DRV and LSRV rules "may represent an attempt to achieve greater granularity and precision than is reasonable and possible in an open, administratively determined tariff mechanism."

The paper said the commission must balance the desire to provide precision in compensation with "the risk that a more sophisticated tariff may result in price signals that do not fully incentivize and motivate developers and customers to make decisions based on the objective of maximizing grid value."

Commissioner Gregg Sayre said that in restructuring the market for distributed energy, "paradoxically, we have to set market rules and even in some cases have to set prices in order to move toward our goals."



Gregg Sayre

Thursday's order adjusts the calculation of DRV to reflect performance during a larger set of hours and to lock in the value for 10 years. It also changed the LSRV — the value of using DERs to avoid distribution system investments — giving such projects compensation for responding to utility calls. PSC staff had called for phasing out the program.

The rules expand Phase One net energy metering eligibility for self-serving projects under 750 kW; modify the Alternative 1 Capacity Value calculation to reflect NYISO monthly prices and solar PV load curves; and modify the Alternative 2 Capacity Value calculation to better reflect actual peak hours.

Diane Burman

Commissioner Diane Burman voted against the VDER measure, saying the late delivery of the draft order — 9 p.m. on April 15 — did not give her enough time to be fully briefed on the matter.

"You can point to the staff white papers and say we just made modifications to that," Burman said. "It's not good enough, especially because it requires going through not just the white papers and looking at the potential modifications, but ... looking at all of the different things that this hits."

John Rhodes

PSC Chairman John Rhodes acknowledged that he had previously heard Burman ask staff to try to get draft orders to the commission well ahead of a scheduled session. Commissioner James Alesi joined Sayre and Rhodes in approving the order.

James Alesi

Storm Response Faulted

The commission concluded investigations into utilities' responses to storms in 2017 and 2018, including two nor'easters that struck the state last March that left hundreds of thousands of customers without power. The commission also *established* the Office of Resilience and Emergency Preparedness to improve the state's ability to respond to the impact of severe weather events.

The PSC accepted a joint settlement agreement on New York State Electric and Gas' and Rochester Gas & Electric's responses to the March 8, 2017, windstorms, which cut power to 250,000 customers (*17-E-0594*).

While National Grid had restored service to 90% of its customers within 36 hours, and all of them by March 12, it took NYSEG until March 13 and RG&E until March 17 to complete work.

"It was disappointing at the time that NYSEG and RG&E took longer to restore service than

NYISO News

National Grid, given relatively comparable service territories and damages," Sayre said.

The settlement requires RG&E to spend $2.8 million and NYSEG $1.1 million on resilience programs and improvements to their emergency response practices. Administrative Law Judge Sean Mullany and Christian Bonvin, Department of Public Service chief of electric distribution systems, testified that the costs would not be reflected in the companies' rate bases or operating expenses.

The PSC also issued a *report* on its investigation into the 2018 winter and spring storms, finding that NYSEG and Consolidated Edison "not only struggled with providing accurate [expected time of restoration] but also did not make optimal use of social media or their websites to keep customers and public officials well informed."

The commission's show cause order directed the utilities to provide a status report by April 26 detailing their implementation of the recommendations and to file revised emergency response plans (ERPs) by May 15 (*19-E-0105*, *et al.).*

Court Action Sought on NYSEG

The PSC also issued an order instructing its counsel to begin a special proceeding against NYSEG in the New York Supreme Court "to stop and prevent future violations" of commission regulations and orders by the utility (*19-E-0288*).

The order cited the DPS' 77 recommendations for NYSEG in its report to implement in its ERP and its conclusion that the company may have violated its ERP on 20 occasions in the 2018 storms. It said the 2018 storms were just the latest in "a pervasive pattern of inadequate response and restoration performance," dating to Superstorm Sandy in 2012.

The New York PSC held its regular monthly session in Albany on April 18.

Burman dissented, questioning the logic of going to court.

"Why would we today, if we have an issue with their pervasive lack of response, why would we say in the settlement and in here that we're good with things?" Burman said. "Plus, we're not factoring in other storms that have happened since then that, my understanding is, NYSEG got credit for doing well."

Burman said she found seeking injunctive relief against NYSEG as dismissive of the commission's authority, as if she was to tell her two children, "Wait until Daddy gets home; he'll tell you to listen to Mommy."

John Sipos, acting general counsel for the PSC, said he would characterize it a different way.

John Sipos

"This order … would authorize counsel to seek an affirmative judicial order requiring compliance," Sipos said. "It is a tool that the commissioners have as part of their enforcement and compliance toolbox. I would respectfully suggest that it is a significant tool, and I would also add that … other state agencies also sometimes seek civil action in New York Supreme Court." ■

NYISO News

FERC Orders Fast-start Rules for PJM, NYISO

Continued from page 1

such changes. The commission also opened a Section 206 investigation into SPP's practices, which remains pending (EL18-35).

NYISO

The commission directed NYISO to make a compliance filing by Dec. 31 and implement the Tariff changes by Dec. 31, 2020.

NYISO currently applies fast-start pricing logic to online and offline fixed block units that can start in 10 minutes. The ISO defines a fixed block unit as one that, "due to operational characteristics, can only be dispatched in one of two states: either turned completely off, or turned on and run at a fixed capacity level."

In the first step of its optimization process, NYISO establishes resources' physical base points in their real-time energy schedules. In the second step, the pricing run, the ISO relaxes the economic minimum operating limit of fixed block units to allow them to be eligible to set prices. The price of offline fixed block units can include a unit's start-up costs.

"However, NYISO neither relaxes the economic minimum operating limits of dispatchable resources (i.e., resources that are not block-loaded), nor does it include the start-up costs of these or any online resources for the purpose of setting prices," the commission said.

FERC acknowledged that NYISO does have fast-start pricing rules and said it is not proposing that the ISO implement a new pricing concept, nor would it require it to change its offline fast-start pricing or its rules on overgeneration "at this time."

The Electric Power Supply Association and the Independent Power Producers of New York filed *comments* in February 2018 supporting the changes, saying that "reflecting all resources which have fast-start capability in energy and operating reserve real-time pricing is a fundamental concept," and "it is critical that fast-start pricing includes all commitment costs."

NYISO's Market Monitoring Unit also filed supportive *comments* last year, saying that, "We agree with this proposed change because it is fully consistent with the economic principle that the competitive price for any good should reflect the marginal cost of supplying the good. Hence, well-designed fast-start pricing rules allow real-time prices to include the cost of committing and running peaking units when they are the marginal source of energy."

PJM

The commission identified six Tariff revisions needed to correct PJM's rules.

First, the commission said PJM must update its software to consider fast-start resources dispatchable from zero to their maximum operating limits for the purpose of setting prices.

Fast-start pricing also must apply to all applicable resources, which FERC said should only include those with a start-up time of one hour or less and minimum run time of one hour or less. Currently, PJM identifies combustion turbines with a two-hour start-up time as fast-start resources.

FERC staffers (left to right) Jorge Moncayo, Kaleb Lockwood and Daniel Kheloussi give a presentation on FERC's fast-start orders for PJM and NYISO. | © *RTO Insider*

FERC also required PJM to:

- Alter the real-time energy market clearing process to consider fast-start resources in a way that is consistent with minimizing production costs;
- Include commitment costs in energy prices for fast-start resources in both the day-ahead and real-time markets; and
- Implement its proposal to use lost opportunity cost payments to offset the incentive for overgeneration or price chasing.

In addition to submitting a compliance filing by July 31, PJM must make a one-time informational report by Aug. 30 explaining how the revisions do not raise new market power concerns.

FERC said PJM has special pricing rules only for block-loaded units — resources whose economic minimum operating limits equal their economic maximums, meaning they have no dispatchable range. The RTO seeks to let them set prices by relaxing the economic minimum operating limit of online block-loaded resources by up to 20% — increased from 10% in 2016.

"Even with this increase, we remain concerned that without allowing relaxation by up to 100%, marginal actions taken by system operators will not be reflected in prices," FERC said.

The commission also said PJM's limiting of applying fast-start pricing to block-loaded resources alone does not reflect the marginal cost of serving load when a dispatchable fast-start resource is needed. It said it agreed with commenters on "a technology-neutral approach [that] ensures that no resource that can perform the same service is unnecessarily excluded from fast-start pricing treatment."

Commissioner Cheryl LaFleur noted that the order limits fast-start resources to those with start-up or minimum run times of one hour or less, rejecting PJM's request for a two-hour threshold.

Daniel Kheloussi, of FERC's Office of Energy Policy and Innovation, said the order finds that resources with start-up and minimum run times exceeding an hour "lack the flexibility to operate in a manner consistent with unforeseen and transient real-time needs, and therefore, commitment and dispatch of such resources are not analogous to a marginal decision." ■

NYISO NEWS

NYISO Studies Grid Transformation, Fuel Security

By Michael Kuser

RENSSELAER, N.Y. — A new NYISO study will examine the energy market and reliability implications of a grid being transformed faster by public policy than by market forces, stakeholders learned last week.

Nicole Bouchez | © *RTO Insider*

"We are addressing the reliability, resilience and flexibility needs of the grid transitioning to a greener New York," Nicole Bouchez, NYISO principal economist, told the Installed Capacity/Market Issues Working Group during an April 15 meeting that discussed the study's *outline*.

New York state policies will add large volumes of zero variable-cost resources to the market, with 15,000 MW of new intermittent resources expected to lead to the retirement of 4,000 to 6,000 MW of conventional generation over the next decade, the outline said.

"We're trying to figure out what has been done and what needs to be done, so we want stakeholder feedback," Bouchez said.

The ISO will release the first draft of the study May 22 for discussion on May 30, ahead of the Board of Directors' June meeting, followed by another draft at the end of August to help inform the board's strategic planning meeting in September, she said.

NYISO thinks the market needs appropriate investment signals to attract, retain and operate new and existing resources while avoiding additional out-of-market compensation.

"The goal here is not to get ourselves into an RMR [reliability-must-run] world," Bouchez said. "We will be looking at market revenue sufficiency; I think in many ways that's the most ambitious part of this whole paper."

Transitional Roles

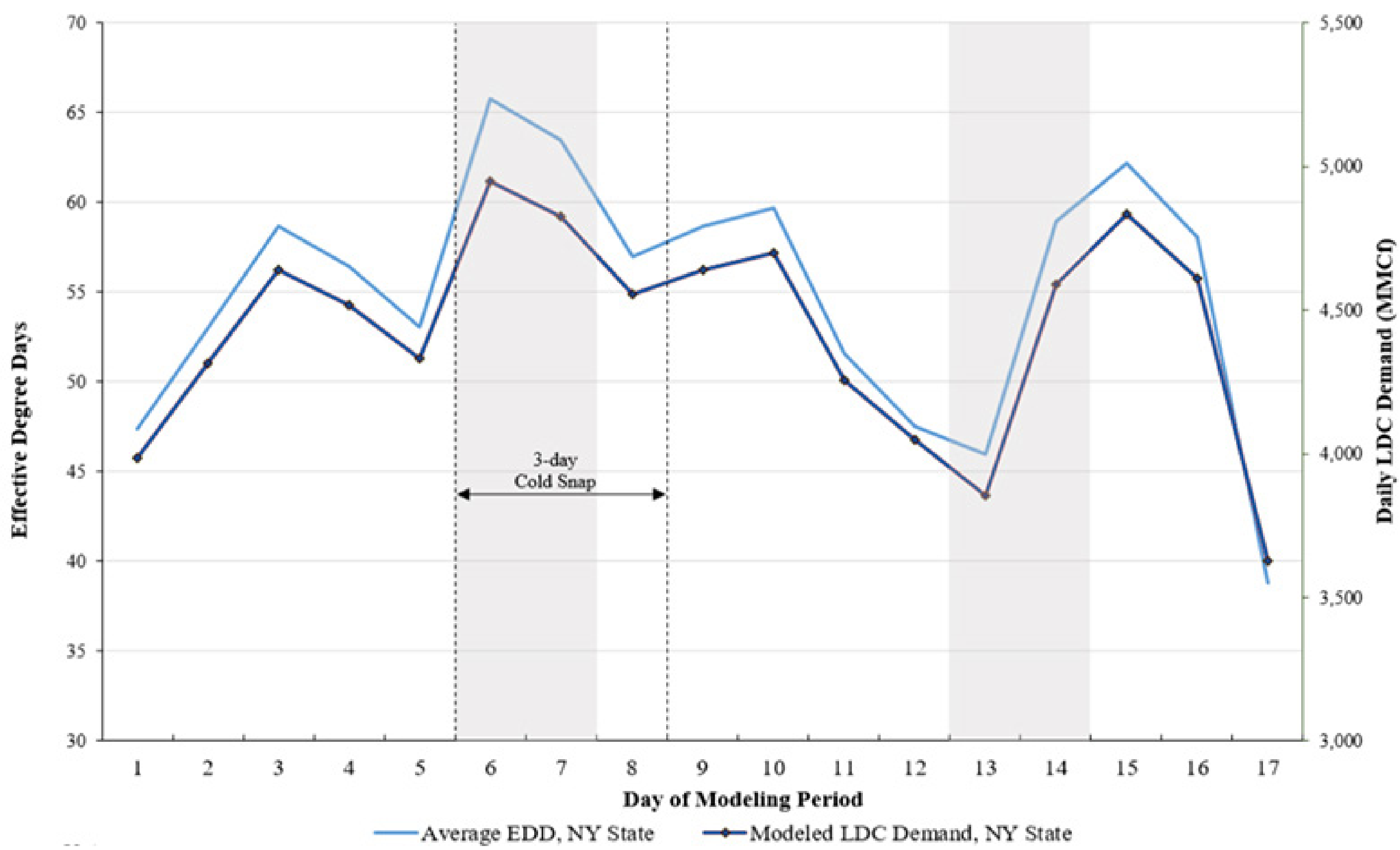
David Clarke, director of wholesale market policy for Power Supply Long Island, asked about the transitional role of carbon pricing.

"There are ways carbon pricing can lead to short-term carbon savings," Clarke said. "The big question is, 'Can the state count on the market to achieve its goals?' Is there a robust market structure that can reliably get you to 2040?"

Bouchez said the ISO sees the situation differently; the state is the one achieving its clean energy goals, with the wholesale market trying to accommodate the changes while remaining effective. (See *NYISO Seeks to Refine Carbon Price Equation*.)

Erin Hogan, representing the New York Department of State's Utility Intervention Unit, asked the ISO to provide more precise definitions of the state's goals. The study refers to a carbon-free grid by 2040, for example, when in fact the current announced target is a carbon-neutral grid, which is not the same thing, she said.

Raj Addepalli, representing the Alliance for Clean Energy New York, asked whether the



Graph shows degree days and local distribution company natural gas demand for the 17-day modeling period to be used in the fuel security study. | *NYISO*

NYISO News

ISO knows of anyone in the world with experience fully operating a system on resources with no variable costs and how markets can be structured in such a scenario.

Bouchez noted California has been thinking about the topic somewhat longer than New York but has not yet figured it out.

Miles Farmer of the Natural Resources Defense Council asked if the ISO has plans to address the inconsistency between its market mitigation rules and the state's announced plan to pursue 100% emissions-free resources. He contended mitigating state-supported resources does not make sense with "a state-driven market entry model."

"We will be looking at the mitigation rules and their compatibility with the desire of the state to have programs that value different attributes," Bouchez said.

The ISO also *announced* April 23 as the date for a second presentation by Analysis Group on the *outline* of a new study to provide additional insights into pricing carbon into NYISO's wholesale electricity markets. The firm's Sue Tierney and Paul Hibbard will present initial analysis results May 14, and the ISO expects to post the final results by the end of May. (See *Analysis Group Presents NYISO Carbon Pricing Study Plan*.)

Fuel Security

NYISO also said it will take a second look at assumptions being used in a separate study commissioned to assess winter fuel and energy security for the New York Control Area.

Hibbard presented additional *details* on the study, reviewing weather and natural gas market assumptions.

"The 17-day cold snap from last year is used in the new model, but it also includes three days from an older and more severe cold period," he said.

Based on review of local distribution company documents, Hibbard said essentially all pipeline export capacity from New York to New England is assumed to be under firm contract to deliver flowing gas or transport stored gas, with 889 MMcfd of natural gas available for electric generation after accounting for retail gas demand in New York, equivalent to roughly 5 GW of electricity generation under severe cold conditions.

Hogan asked what kind of validation process Analysis Group used "to make sure [it was] in the ballpark with results."

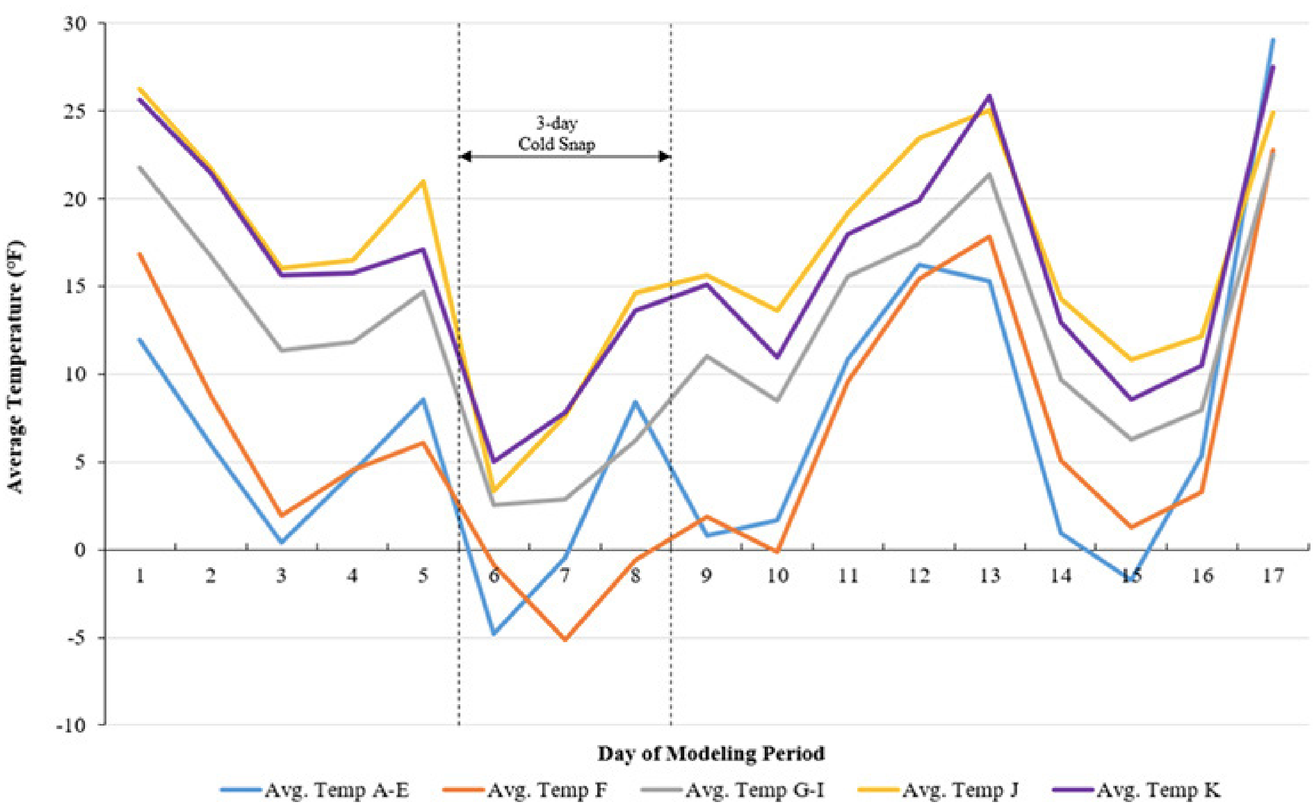
"We're trying to see where the risks are to the electric power system based on natural gas supply constraints, not the worst-case or best-case scenario," Hibbard said.

Wes Yeomans, the ISO's vice president of operations, said, "Remember, on the supply side, we're going to have Indian Point out and no coal. ... Things will be different in 2023 from what they were in earlier forecasts."

One stakeholder mentioned the importance of considering the impact of energy storage on fuel demand, given the state's programs to help finance development of 800 MW of new energy storage resources. (See *NYPSC Expands Storage, Energy Efficiency Programs*.)

"We likely will not change base assumptions in the initial scenario but will address storage and various other stakeholder concerns in the scenarios and as part of the findings of the analysis," Hibbard said.

Analysis Group currently expects to present initial findings of the energy security study in May, additional findings in June and final results in July. ■



Weather assumptions for the fuel security study will now include data from a previous three-day severe cold snap. | *NYISO*

NYISO Business Issues Committee Briefs

Committee OKs New DER Market Design

NYISO's Management Committee should approve Tariff revisions on a new market design for distributed energy resources, the Business Issues Committee recommended Wednesday.

Michael Lavillotti, the ISO's senior market design specialist, presented an *outline* of the new construct. The aspects range from electrically mapping each individual DER or facility for transmission node-level granularity, to authorizing entities to provide meter services to aggregations in the DER and reliability-based demand response programs.

The motion passed with 89.25% affirmative votes, despite concerns from several stakeholders about issues such as mitigation and the terms for dual participation, under which DERs that provide wholesale market services can also provide services to another entity such as a utility or host facility.

Couch White attorney Amanda De Vito Trinsey, representing New York City and Multiple Intervenors, a coalition of large industrial, commercial and institutional energy customers, said that despite concerns with several aspects of the market design and changes to capacity values for resources (including resources participating in the reliability-based DR program), her clients support the proposal.

NYISO Vice President for Market Operations Emilie Nelson and Senior Vice President for Market Structures Rana Mukerji said the ISO feels it struck a fair balance between reliability and market risk, and that stakeholders can help refine and adjust the Tariff rules as they all gain experience working with DERs.

"Don't let the perfect become the enemy of the way better, and this is way better than what we started with," said BIC Chair Aaron Breidenbaugh, who represents small consumers.

New External SRE Penalty

The BIC also recommended the MC approve a new external supplemental resource evaluation (SRE) *penalty* regime to improve the ISO's ability to call on external resources that have sold into its markets. The changes would take effect in the third quarter.

Amanda Carney, NYISO capacity market design specialist, said all external capacity suppliers required to offer their energy at an external proxy must bid at the offer floor, be operating and available, and flow the scheduled transaction.

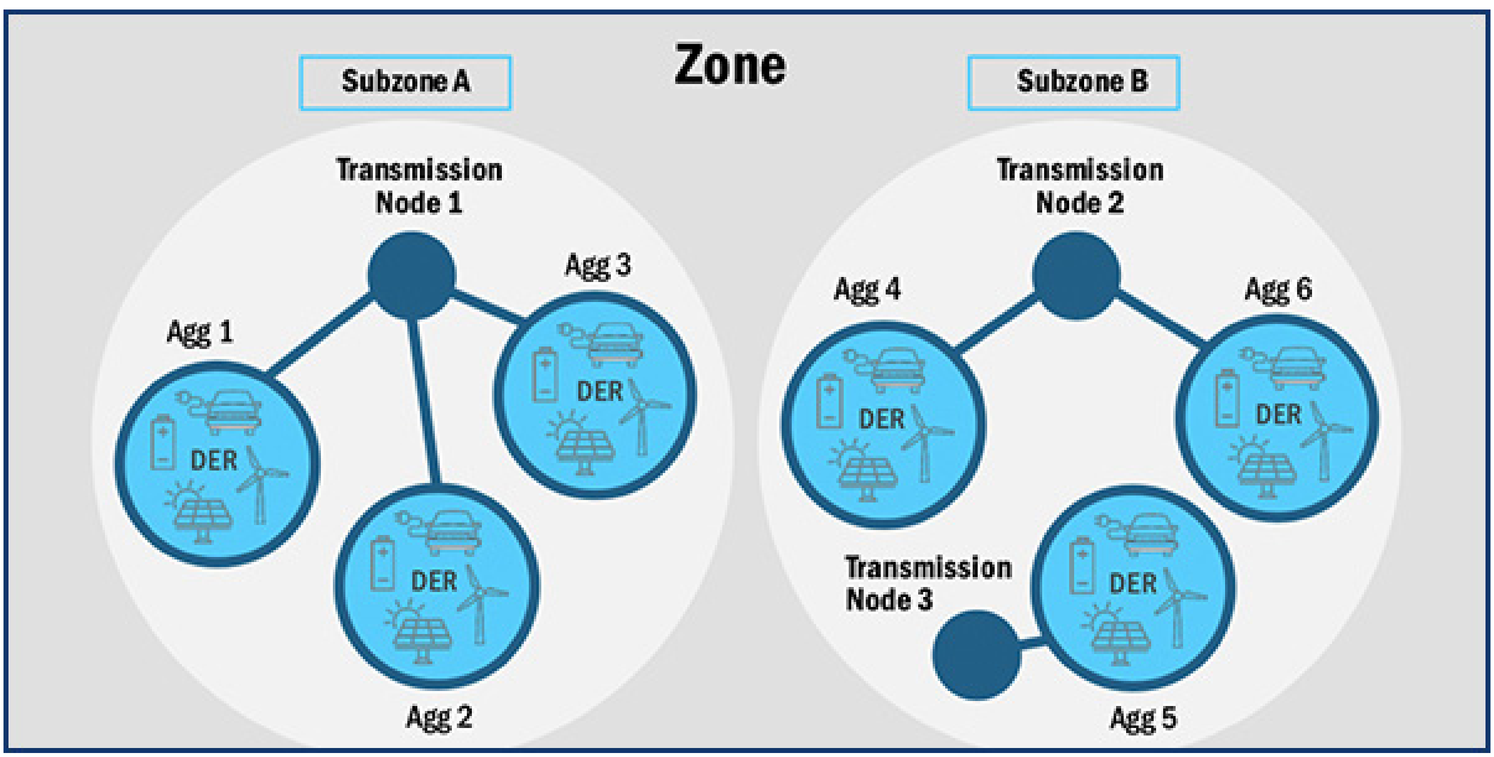
Under the new proposal, any external resource that fails to meet the criteria will be subject to the penalty, which is equal to 1.5 times the applicable spot price multiplied by the number of megawatts of shortfall and the percentage of the SRE call hours that a supplier fails to respond to.

External capacity suppliers would not be subject to the penalty if their failure to deliver is beyond their control, Carney said.

Howard Fromer, director of market policy for PSEG Power New York, thanked the ISO for the greater comparability in treatment of internal and external resources, and particularly for not penalizing external resources for failure to perform because of events beyond their control.

"Though the penalty is still draconian, we understand this is an interim measure to get the electrons here," Fromer said. "We believe something could be done in the future to avoid using bidding gymnastics to achieve the goal and instead make bids that reflect costs in a more reasonable way to ensure reliability and performance."

Under the new penalty provisions, the ISO will calculate deficiencies monthly, using the total



The ISO would electrically map each individual DER or facility for transmission node-level granularity under its proposed market design. | *NYISO*

NYISO News

number of SRE call hours in a given month that the resource could be online for and the total number of megawatts of shortfall in that month, Carney said.

External capacity suppliers are currently able to receive capacity payments without providing energy if their bids are uneconomic, even when called upon by NYISO during critical system conditions.

The BIC also approved *changes* to the accounting and billing manual, including to local reliability rule names, to be in line with changes made last May by the New York State Reliability Council.

LBMPs, Gas Prices up Slightly in March

NYISO locational-based marginal prices averaged $34.91/MWh in March, up about 4% from February and nearly 17% from the same month a year ago, Mukerji said in delivering the monthly operations *report*.

Year-to-date monthly energy prices averaged $42.54/MWh, a 29% decrease from a year ago.

Day-ahead and real-time load-weighted LBMPs came in higher compared to February. Average daily sendout was 411 GWh/day in March, compared with 436 GWh/day in February and 413 GWh/day in the same month a year ago.

Transco Z6 hub natural gas prices averaged $2.93/MMBtu for the month, up 6.5% from February and 2.6% from a year ago.

Distillate prices were up about 2.6% year over year and were mixed from the previous month, with Jet Kerosene Gulf Coast averaging $14.08/MMBtu, down from $14.21/MMBtu, while Ultra-low Sulfur No. 2 Diesel NY Harbor rose to $14.18/MMBtu, up from $14.02/MMBtu in February.

March uplift increased to -33 cents/MWh from -44 cents/MWh in February, while total uplift costs, excluding the ISO's cost of operations, came in higher than the previous month.

The ISO's 31-cents/MWh local reliability share in March was up from 11 cents/MWh the previous month, while the statewide share dropped to -64 cents/MWh from -55 cents/MWh in February.

The Thunderstorm Alert cost was 1 cent/MWh, up from the usual $0. ■

— Michael Kuser

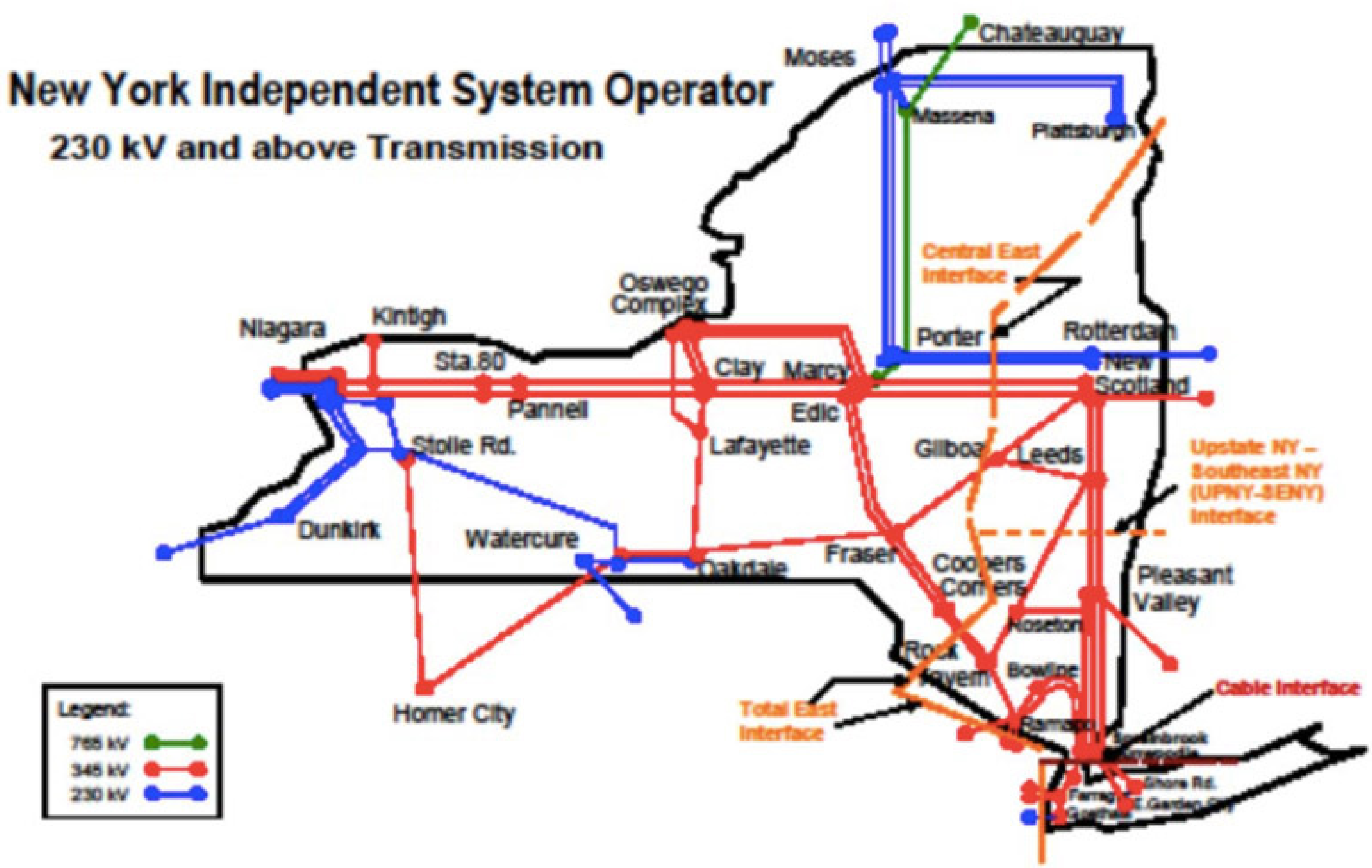


Figure 1: NYISO 230 kV and above Transmission Map

| NYISO

PJM News

NJ Approves $300M ZECs for Salem, Hope Creek Nukes

By Christen Smith

New Jersey regulators approved zero-emission credits totaling $300 million for all three of the state's nuclear reactors on Thursday, nearly a year after the governor signed off on an ambitious energy plan aimed at boosting the use of carbon-free resources to 50% over the next decade.

The state Board of Public Utilities permitted the subsidies for Public Service Electric and Gas' Hope Creek Nuclear Generating Station and Salem Nuclear Power Plant — co-owned by Exelon — after determining the facilities qualified for relief because financial strain could shutter them within three years. To qualify for ZECs, the plants must be licensed by the U.S. Nuclear Regulatory Commission through 2030, contribute to the state's improved air quality and not receive any other subsidies.

"We do not make this decision lightly, and the board must balance protecting ratepayers with our responsibility to the citizens of the state," BPU President Joseph Fiordaliso said in a *news release* on Thursday. "We have a moral obligation to our fellow citizens to do everything we can to decrease carbon emissions. In making this decision, the board considered fuel diversity, resiliency, [the Regional Greenhouse Gas Initiative], the New Jersey economy and environmental impact, and we've concluded that now is not a time to move forward in a way that will remove nuclear from our energy mix and ultimately increase air pollution and carbon emissions in our state."

The plants will receive ZECs for three years and the balance of the first energy year following selection. They will be subject to review by the BPU for additional three-year periods.

The board said nearly 40% of New Jersey's emissions-free energy comes from nuclear power, making it the largest source of carbon-free energy in the state.

In 2016, according to the U.S. Energy Information Administration, the combined generation of the Salem and Hope Creek plants was 25.3 million MWh, 33.6% of the state's 75.4 million MWh usage. The state's Office of Legislative Services calculated that a 0.4-cents/kWh charge assessed on ratepayers would generate $301.4 million based on 2016 consumption, translating to a ZEC cost of about $10/MWh.

"We are pleased with the decision to award ZECs to PSE&G to help support New Jersey's primary supply of zero-carbon electricity," PSE&G said in a *press release*. "The BPU just saved the people of the state hundreds of millions of dollars in what would have been higher energy costs, thousands of jobs lost and tons of environmentally damaging air emissions."

Hope Creek Nuclear Plant

Critics argue the "bailout" money would be better invested in renewable resources like wind and solar.

"When they are saying they are doing it for climate change, they are putting out more hot air," said Jeff Tittel, director of the New Jersey chapter of the Sierra Club. "It's going to end up undermining our renewable energy programs, especially offshore wind and solar."

Tittel described Thursday as "one of the most shameful days" in BPU history because he said commissioners pushed through the largest corporate subsidy in state history without any justification.

"Their own independent consultant said the subsidy wasn't needed," he said. "Even the commission said PSE&G didn't qualify based on financial needs. So really the height of hypocrisy was them basing it on clean energy goals."

Illinois and New York approved ZECs for their nuclear plants in 2016 and 2017. State legislators in Pennsylvania, Ohio and Maryland are mulling similar legislation. ■

PJM News

FERC to PJM: Clarify Allowable Costs for Energy Market Offers

By Christen Smith

FERC handed PJM a mixed ruling last week on a set of proposed Tariff and Operating Agreement revisions intended to equalize the cost recovery treatment of gas-fired plants with that of other thermal generators.

The commission April 15 approved the Tariff changes, agreeing PJM's existing rules "unduly discriminate" against combined cycle and combustion turbine generators by preventing them from recovering inspection costs as a "maintenance adder" in their energy prices.

Those types of variable costs are considered related specifically to electricity production and should be recoverable in the energy market, the commission said (*ER19-210*). Many nuclear and fossil generators currently factor these expenses into their avoidable-cost rates in the capacity market.

In approving the Tariff changes, FERC rejected the PJM Independent Market Monitor's argument that major maintenance costs incurred as a result of electricity production should be recovered in the capacity market because they are not short-run marginal costs. The PJM Load Coalition likewise insisted variable operations and maintenance costs belonged in capacity market offers only.

The commission also dismissed concerns that the changes risked double recovery by generators in both the energy and capacity markets.

"We accept PJM's Tariff revisions to clarify that all resource types are prohibited from recovering variable maintenance costs that are directly attributable to the production of electricity in their avoidable-cost rate in the capacity market," the commission wrote.

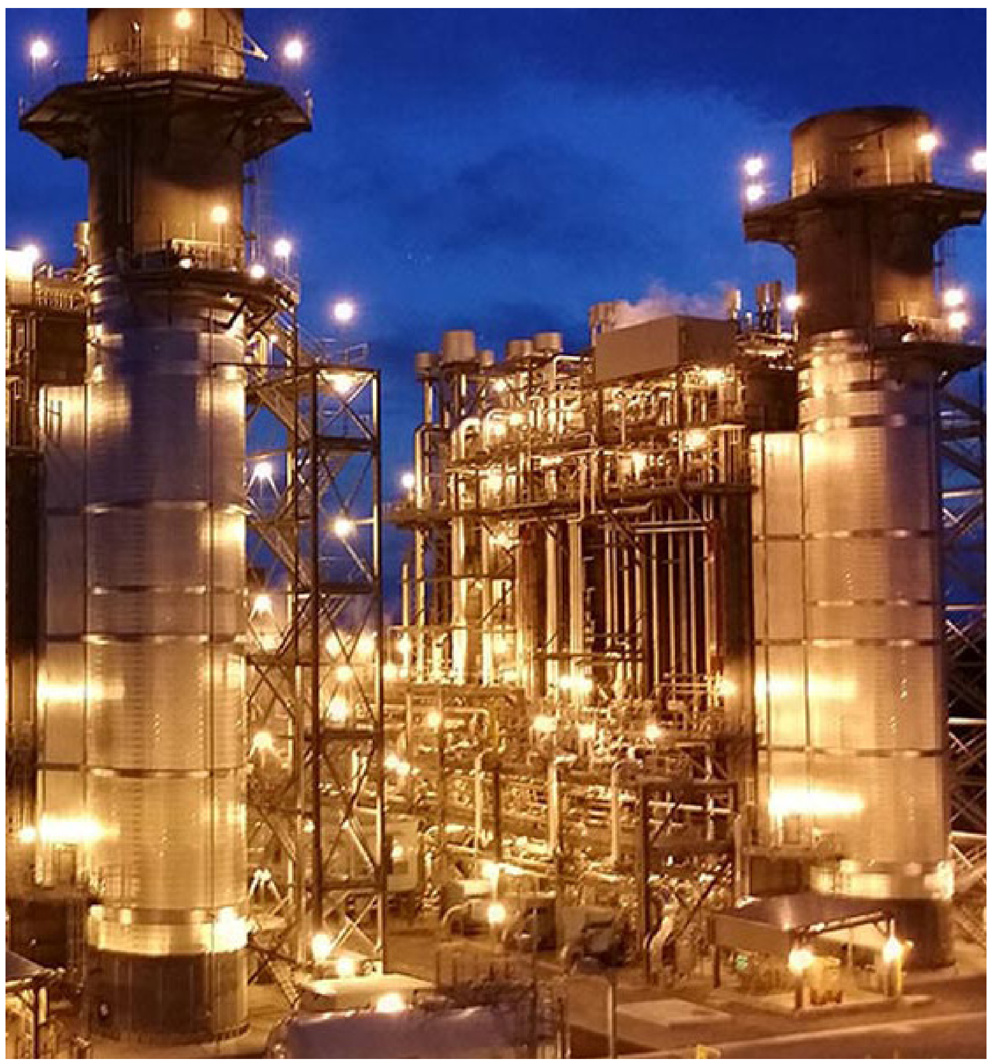
But FERC found related changes in PJM's Operating Agreement to be "unjust and unreasonable" because "the definitions of maintenance adders and operating costs fail to provide sufficient clarity with respect to permissible cost components of cost-based energy market offers."

The commission directed PJM to submit a compliance filing clarifying what maintenance costs sellers can include in their energy market offers. The revised OA must do the following:

- Create a single, properly defined operating cost component.
- Remove "incremental fuel costs" and "other incremental operating costs" from the list of permissible components in a cost-based offer.
- Add a definition for "opportunity costs" and create a new section detailing this component.
- Create a new section for the "application of cost components to three-part cost-based offers."
- Move definitions for "maintenance adders" and "operating costs" to a new opportunity costs section.
- Expand the list of maintenance costs to include cooling towers, fuel and water pumps, emissions-reduction catalyst equipment, and replacement of filters and cartridges.
- Add sections to memorialize PJM's process of calculating major maintenance costs based on 10- or 20-year histories.
- Revise the section related to the review of maintenance adders and operating costs to require market sellers to specify the maintenance history years on which their maintenance adders are based.

The Monitor had pushed for the required clarifications.

On the same day, FERC also accepted PJM's quadrennial revision of its variable resource requirement curve used in the Reliability Pricing Model, effective Jan. 17 (*ER19-105*). ■



FERC agreed with PJM that its existing rules for maintenance cost recovery discriminates against CC and CT generators. | *Panda Power Funds*

PJM News

PJM: Dismiss Monitor's Offer Cap Complaint

By Christen Smith

PJM wants FERC to toss out the Independent Market Monitor's complaint about its default market seller offer cap (MSOC), saying the IMM's February filing did not prove current rules encourage abuse of market power (*ER19-47*).

In an April 9 *response* filed with the commission, PJM said the Monitor didn't provide enough evidence that its current cap — approved four years prior as part of the RTO's Capacity Performance construct — and the results of Base Residual Auctions suddenly became unjust and unreasonable.

PJM said the commission's order approving CP "explained that the default MSOC is just and reasonable because it reflects the amount that a competitive resource would accept to be committed as a capacity resource."

"In particular, it is designed to allow capacity market sellers to recover the costs, investments and expenses needed to ensure that their resources can perform during emergencies occurring at any time of the year. In other words, the default MSOC is intended to reflect the opportunity cost that a resource faces when choosing whether to become a committed capacity resource," PJM said.

The Monitor said in its initial filing that PJM's MSOC has been inflated by the "unreasonable and unsupported" expectation of 30 performance assessment hours (PAHs) annually. As a result, the Monitor said, it has been prevented from effective mitigation of market power, able to subject only a small number of very high offers to unit-specific cost reviews. (See *Monitor Asks FERC to Cut PJM Capacity Offer Cap*.)

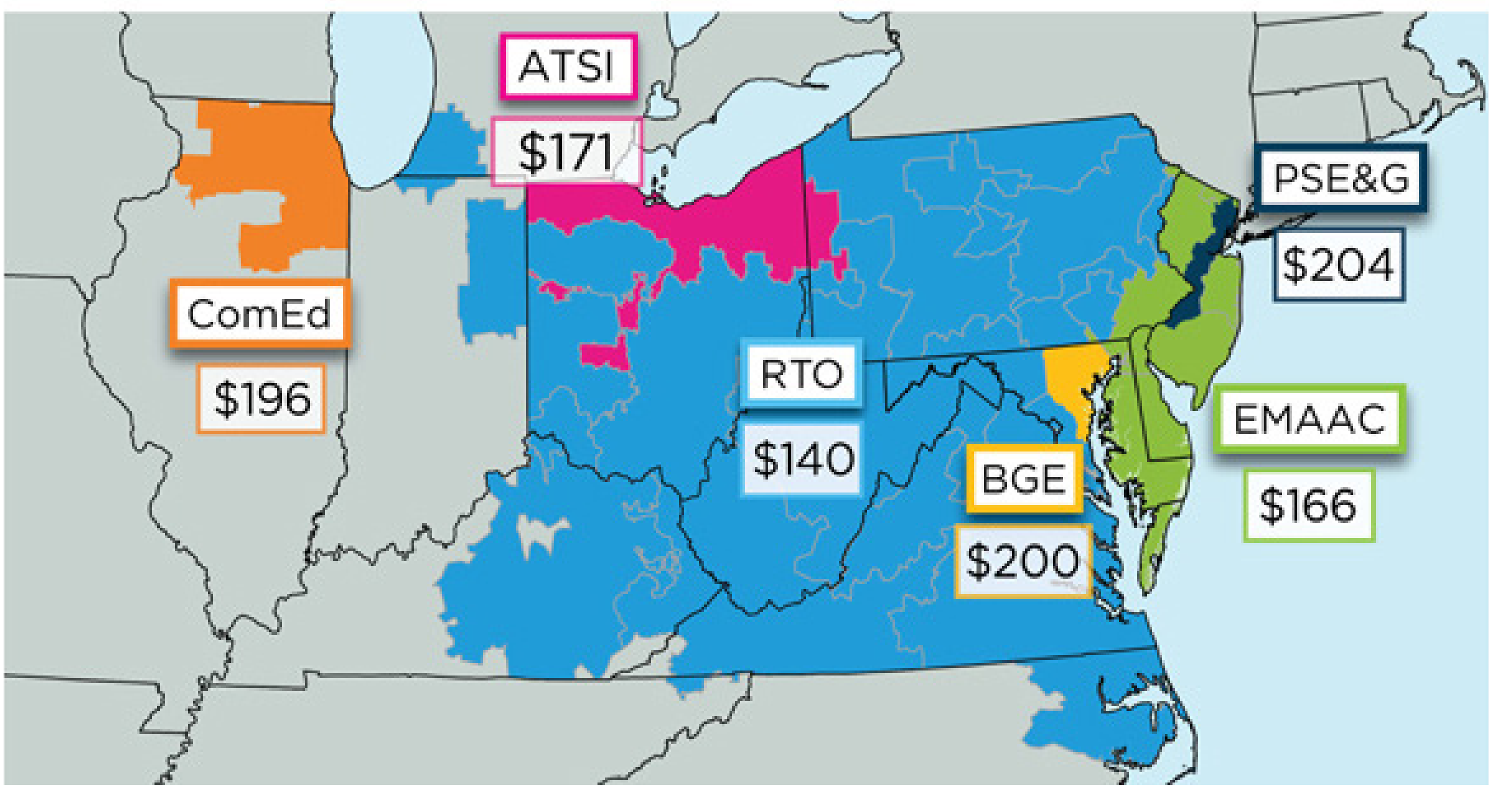
Unit-specific MSOCs are supposed to be based on the opportunity cost of taking on a CP obligation, with its expectations of bonus payments or penalties for performance during an emergency, PJM said. (The time span for measuring performance was changed from PAHs to five-minute performance assessment intervals (PAIs) in compliance with FERC Order 825 in 2018.)

In August, the Monitor concluded that ratepayers were overcharged by $2.7 billion (41.5%) in the 2018 BRA because of economic withholding encouraged by the inflated MSOC. (See *IMM: PJM 2018 Capacity Auction was 'Not Competitive'*.)

PJM asked the commission to reject the Monitor's proposed replacement rate of 60 PAIs and instead adopt a method that applies the same measurement to equations for both the default MSOC and the nonperformance charge. This rate, the RTO asked, would not take effect until after the 2022/23 BRA, for which several compliance deadlines for market sellers have already passed.

"The Market Monitor's proposal is unjust and unreasonable due to, among other reasons, the disconnect between the number of expected performance assessment intervals in the nonperformance charge rate and the default MSOC," PJM said. "Retaining the same value of performance assessment intervals in both equations is essential to maintaining the underlying logic of the existing default MSOC equation." ■

PJM 2021/22 Capacity Auction Results



PJM said the Market Monitor isn't authorized to file a complaint on the market seller offer cap. | *Panda Power Funds*

PJM News

PJM MRC/MC Preview

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

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

Consent Agenda (9:10-9:20)

Members will be asked to endorse the following manual revisions:

B. *Manual 11: Energy & Ancillary Services Market Operations*: Reflects the addition of location fields in DR Hub.

C. *Manual 11: Energy & Ancillary Services Market Operations*: Part of the biennial review.

D. *Manual 21: Rules & Procedures for Determination of Generating Capability*: Related to generator testing, excluding PJM's proposed effective load-carrying capability calculation deferred for endorsement until the May MRC meeting.

E. *PJM Regional Business Practices*: Document associated with the new OASIS application.

1. Must-offer Exception Process (9:20-9:35)

Stakeholders will decide whether to grant PJM authority to force capacity resources into energy-only status for failing to meet Capacity Performance requirements.

Members will first consider revised must-offer *rules* approved by a 79% vote of the Market Implementation Committee in November. They would require existing capacity resources not offered in three consecutive auctions to change to energy-only status. Capacity interconnection rights (CIRs) of such resources would be terminated one year from the switch to energy-only, unless the rights holder submits a new generation interconnection request within that year using those same CIRs.

If the first proposal fails to clear the two-thirds sector-weighted threshold, members will vote on an Exelon *proposal* that received a 61% MIC vote in March. It would allow capacity resources to voluntarily switch to energy-only status but would not allow PJM to force a switch. Eighty-five percent also said they preferred the Exelon rules over the November proposal. (See *Showdown Set on PJM Must-Offer Exceptions*.)

Both proposals, which would require changes to Manual 18 and the Tariff, received first reads at the March 21 MRC meeting.

4. Carbon Pricing Problem Statement/ Issue Charge (10:00-10:20)

Stakeholders will vote on a *problem statement* and *issue charge* to consider carbon pricing in PJM's 13-state territory, an initiative that received largely supportive statements from members at the March 25 MRC. (See *PJM Members Welcome Carbon Pricing Talks*.)

Michael Borgatti of Gabel Associates presented a first read of a problem statement and issue charge at the MRC last month that would task stakeholders with creating rules to address carbon leakage and help states meet greenhouse gas reduction policies. Borgatti made the presentation on behalf of the *Independent Energy Producers of New Jersey*, which includes NextEra Energy and PSEG Power.

5. Surety Bonds (10:35-10:50)

The MRC will consider two *proposals* to allow surety bonds as an additional form of collateral.

The first *proposal* members will vote on would allow surety bonds as collateral for all market purposes except financial transmission rights, with a $10 million cap per issuer for each member and a $50 million aggregate cap per issuer. It won 61% of stakeholder support at the Credit Subcommittee and the MIC.

If the first proposal fails to win a two-thirds weighted vote, members will consider Exelon's alternative *plan*, which would allow surety bonds as collateral for FTRs and other market purposes, with a $20 million cap per issuer for each member and a $100 million aggregate cap per issuer. (See "Surety Bonds," *PJM MRC/MC Briefs: Dec. 6, 2018*.)

Exelon's proposal earned 53% support at the subcommittee and 58% support at the MIC. The company had asked to delay the vote on the issue until the Board of Managers' report on the GreenHat Energy FTR default, which was released last month. (See *Report: 'Naive' PJM Underestimated GreenHat Risks*.)

6. Manual 14B Amendments

LS Power's Sharon Segner is expected to seek another 60-day delay on a vote on her company's proposal to amend Manual 14B: Regional Transmission Planning Process. The *proposal* would add language that a transmission owner's supplemental project "will generally be removed from" the Regional Transmission Expansion Plan following a final order by a state siting agency rejecting the project. Supplemental projects are proposed by TOs and are not required for compliance with PJM's reliability, operational performance or economic criteria.

Aaron Berner, PJM manager of transmission planning, told the Planning Committee on April 11 that stakeholders agreed to another deferral after conducting two educational sessions last month to discuss how projects are removed from the RTEP. (See "LS Power Will Seek 2nd Deferral on Transmission Replacement Language," *PJM PC/TEAC Briefs: April 11, 2019*.)

7. Financial Risk Management Senior Task Force Charter (10:50-11:20)

Stakeholders will consider a *charter* to form a Financial Risk Management Senior Task Force in the wake of the GreenHat default.

PJM suggested assembling the task force as soon as May 2 to begin the overhaul of credit and risk management rules, market design, membership qualifications and processes, and the stakeholder process itself.

The task force is a response to a board-commissioned investigation that found RTO officials were slow to realize the risk posed by GreenHat and did not respond quickly to warnings by other market participants. PJM CEO Andy Ott said the default indicated a need to revise the RTO's stakeholder process. He *said* he has developed "an action plan to strengthen the PJM organization and improve our processes and communication." (See "Financial Risk Management Task Force Proposed After GreenHat Report," *PJM MIC Briefs: April 10, 2019*.)

— Christen Smith

SPP

FERC Tells SPP to End Exit Fee for Non-TOs

By Tom Kleckner

FERC on Thursday directed SPP to eliminate its exit fee for members who are not transmission owners or load-serving entities, granting a complaint by the American Wind Energy Association and the Wind Coalition (*EL19-11*).

The commission found the RTO's exit fee to be unjust and unreasonable "because it creates a barrier to SPP membership for non-transmission owners and because it appears to be excessive."

"SPP's exit fee for non-transmission owners … is not needed to maintain SPP's financial solvency or avoid cost shifts, and is excessive as a means of ensuring stability in membership and members' financial commitment," the commission said.

AWEA applauded FERC's decision, saying the exit fee prevented environmental groups, consumer advocates, independent power producers, power marketers and other market participants from "contributing to [SPP's] decision-making process."

"We look forward to working with SPP to develop a more inclusive stakeholder process that will lead to better outcomes for ratepayers," Amy Farrell, AWEA's senior vice president of government and public affairs, said in a statement.

SPP said it was unable to respond to the order until it reviews it to "fully determine its implications."

AWEA and the Wind Coalition, now known as the Advanced Power Alliance (APA), filed the complaint in November, charging that the exit fee results in unjust and unreasonable rates "because there is no causal relationship between a non-TO/LSE's termination of membership and the majority of the exit fee" and because the exit fee is "a practice that directly affects jurisdictional rates … by creating a barrier to membership for non-TOs/LSEs," resulting in their under-representation as voting members in SPP.

The complainants argued than an administrative fee would be a more "appropriate mechanism" for SPP to recover its ongoing obligations, as do other RTOs and ISOs. They contended SPP does not attempt to correlate the exit fee's assessment with the amount of costs caused by a withdrawing non-TO/LSE member, saying a public interest entity with no market activity would pay the same exit fee as an entity with thousands of megawatts of generation in the RTO.

FERC agreed, noting the only instance of an exit fee's assessment came in 2015 when Trans-Elect Development Co. was charged $822,008 upon the involuntary termination of its membership for nonpayment of obligations. The commission said SPP calculates that the exit fee for an entity without load would be approximately $621,851, as of October 2018, and found that at even that level, the exit fee "could place a significant burden on smaller entities or new market entrants that are not transmission owners."

The commission pointed to comments from DC Energy, EDF Renewables, E.ON Climate & Renewables, Invenergy Energy Management, TradeWind Energy, Texas Industrial Energy Consumers, Interwest Energy Alliance and public interest organizations that indicated they had not become members "because of the potential burden associated with paying the exit fee."

SPP requires its members to pay a $6,000 annual membership fee. The exit fee is defined as the sum of the withdrawing member's existing obligations (including any unpaid dues or assessments and any costs directly incurred by SPP because of the membership termination) and the member's share of SPP's outstanding long-term financial obligations (loans, leases and pensions) and general and administrative overhead for a three-month period.

FERC said SPP has grown "significantly" since 2006, when it last ruled on its exit fees. At the time, long-term financial obligations amounted to about $25 million, the commission said. But as the RTO has grown by building out its transmission footprint and administering an energy imbalance market and its Integrated Marketplace, it said, so have SPP's long-term obligations.

SPP's long-term debt peaked at more than $258 million in 2012, when it was developing the Integrated Marketplace. The markets went live in 2014, and SPP's long-term debt has subsequently dropped to more than $215 million.

Membership benefits include the ability to: vote on SPP initiatives; elect members to the Board of Directors; propose changes to the Tariff, business practice manuals and governing documents; serve on committees, task forces and working groups; participate in closed or executive session discussions; request dispute resolution; and appeal decisions to the board.

Nonmembers or their representatives can attend open meetings and submit comments on proposals. They can also participate in the Integrated Marketplace and take transmission service under the Tariff.

Steve Gaw, a former Missouri legislator and regulator, has long represented the APA at SPP stakeholder meetings. As a regulator, Gaw also served on SPP's first Regional State Committee.

Invenergy technician overlooks wind farm. | *Invenergy*

SPP Granted Delay for Tariff Revisions

In a second order Thursday, the commission granted SPP's request to defer revisions to its Tariff because of an implementation delay in a new settlement management system (*ER17-1568*).

SPP said several Tariff revisions were dependent on changes built into the settlement system, but that the system had "encountered developmental delays."

The new settlement system was originally projected to go live May 1. However, that date has now been pushed back to Feb. 1, 2020. ■

SPP

SPP MOPC Briefs

Z2 Credits Could Soon Become an Issue Again

TULSA, Okla. — Like the walking dead, Tariff Attachment Z2 keeps returning from the grave, much to the consternation of SPP and its stakeholders.

Paul Suskie | © *RTO Insider*

General Counsel Paul Suskie last week laid out before the Markets and Operations Policy Committee the implications of FERC's February reversal of a waiver it had previously issued to SPP on the attachment. (See *FERC Reverses Waiver on SPP's Z2 Obligations*.)

April's MOPC meeting | © *RTO Insider*

The commission ordered SPP to refund, with interest, credit payment obligation amounts dating back to 2008, except for the one-year billing adjustment limit allowed in the Tariff. SPP has estimated the obligations to be approximately $200 million.

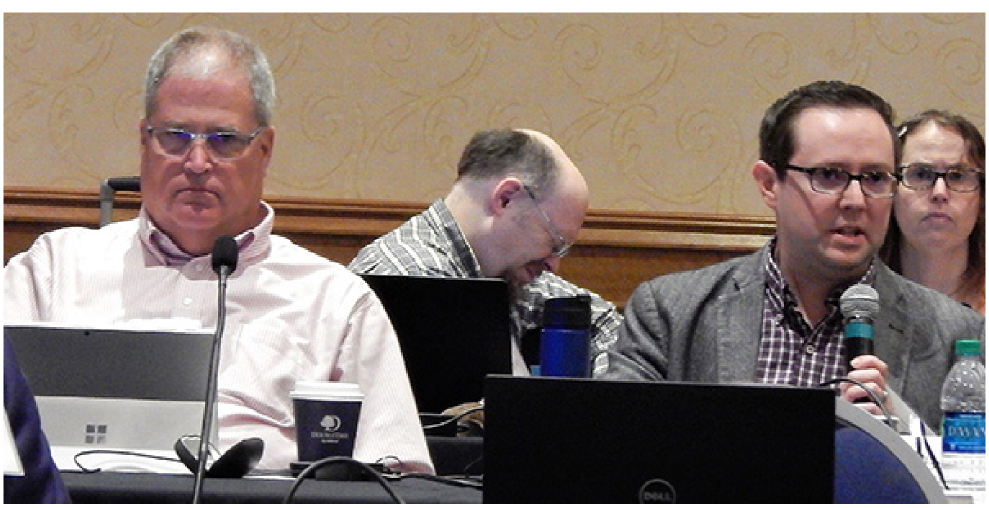
SPP was seeking a retroactive Tariff waiver allowing to invoice transmission service customers for Attachment Z2 credit payment obligations for the 2008-2016 time period prior. FERC ruled the waiver request to be retroactive ratemaking, saying SPP did not provide adequate notice.

"In my opinion, FERC had no idea of what it was unraveling," Suskie told the MOPC on April 16. "We've listed 20 issues that are going to be challenges if we undo this."

Included among those is how SPP will redistribute to transmission owners' point-to-point revenues it had clawed back in the historical settlements process. Staff said it would share the full list of issues with stakeholders.

Suskie said SPP and other parties on April 1 asked FERC for a rehearing and clarification of the order (*ER16-1341*). He also said the RTO is developing a compliance plan to be filed with FERC no later than June 28.

Attachment Z2 details how sponsors that fund network upgrades can receive reimbursements through transmission service requests, generator interconnections or upgrades that could not have been honored "but for" the upgrade. SPP said that delays in implementing computer software kept it from listing certain creditable upgrades in aggregate facilities study reports, calculating and assessing costs, and distributing credits to transmission customers before August 2016.



GridLiance's Noman Williams (left) and Brett Hooton | © *RTO Insider*

SPP Proposing to Assign Kansas NTC to GridLiance

SPP's proposal to assign the Kansas Power Pool's (KPP) notification to construct (NTC) a 69-kV rebuild to GridLiance High Plains met pushback from the MOPC over increased costs within transmission zones and the usual turf battles between the RTO's legacy TOs and smaller entities.

"If this was someone else other than GridLiance, or another [investor-owned utility], you would gladly accept the assignment," Tri-County Electric Cooperative's Chris Giles complained to the committee's membership.

"Amen!" came a voice from the opposite corner of the meeting room.

The project was originally assigned to KPP in February 2018. Rather than reconductor 4 miles of 69-kV lines from the city of Winfield, Kan. — a KPP member — to a Westar Energy substation, KPP decided on a full rebuild and raised the initial estimate from $1.5 million to $3.6 million.

Larry Holloway, KPP's assistant general manager for operations, said his company has been unable to gain the obligation to build from Kansas regulators, which led to GridLiance's involvement. The five-year-old company, which partners with public utilities, *announced* in January a "long-term partnership" with Winfield in which GridLiance would acquire 65% of the city's 29 miles of 69-kV facilities and invest in a "needed reliability upgrade."

SPP

SPP said GridLiance's own data show it will increase the annual cost to customers if it retains the NTC, largely because its tax requirements are greater than KPP or Winfield's.

GridLiance High Plains President Brett Hooton said the cost of the project itself remains the same, regardless of the assignment from Winfield to GridLiance. He said SPP's cost estimate over the project's four-year life works out to $75,000/year.

"The cost difference on rates primarily relates to the fact that GridLiance is a taxable entity and the city is not," Hooton told *RTO Insider*. "Any time there is an assignment from a municipal utility to a taxable utility, there will be similar cost impacts."

Hooton said GridLiance intends to build the facilities with 138-kV capabilities, matching Westar's existing infrastructure.

The issue is likely to receive similar pushback during the April 29-30 Regional State Committee and Board of Directors meetings. SPP's Tariff required staff to "advise" the MOPC of the proposal, with the final decision being left to the board.

"If the board were to reject the assignment because of the small cost impact, it would set a precedent that municipal utilities would virtually be unable to ever assign or novate an NTC because of their tax-exempt status," Hooton said.

Staff Explains 9-Month Delay to New Settlement System

Staff briefed the MOPC on its delayed new settlement system, which was supposed to go live May 1. However, a condensed project timeline and missed deliveries left developers without enough time to build software and train end-users, pushing the implementation back to Feb. 1, 2020.

SPP announced the delay to project participants on Feb. 15, saying the project was in red status because of "various system issues" and that it was pausing member testing as it reassessed the timeline, remaining work and required testing.

Don Shipley | © *RTO Insider*

Settlements Director Don Shipley said incorporating additional applications and links to other systems increased the project's risk. The settlement system replacement project will consolidate several systems and automate manual processes, reducing staff costs and improving personalized customer service, he said.

"We had several parallel paths — development, testing, training — all going on at the same time, rather than back-to-back," Shipley said.

Shipley said the inability to run the system end-to-end meant staff couldn't do day-in-the-life testing, which also meant members couldn't "appropriately" test their internal systems. Even then, there were frequent errors in the software's calculations, he said.

"The right decision was to delay and ensure we have a system that worked. The most catastrophic thing that could happen is if we couldn't settle the entire system when we cut over," Shipley said.

Following several weeks of analysis and review, SPP has worked to improve its communications both internally and with the vendor, *Symphono*. Daily meetings, called "scrums," are held to "understand what is going to be happening" and to discuss any issues at the vendor level. Staff are now focused on the "total development effort," with a June 28 deadline to complete all code, and internal testing and training has been increased.

AEP's Richard Ross (left) makes a point as East River Electric's Mark Hoffman observes. | © *RTO Insider*

Lanny Nickell confers with SPP's Dustin Smith (left) and Derek Wingfield on a presentation. | © *RTO Insider*

"We don't want this to become a pattern. What are we doing to learn from mistakes like this and Z2 to ensure it doesn't happen again?" asked Kansas City Power & Light's Denise Buffington, the MOPC's vice chair.

"I understand where you're coming from, with the Z2 followed by the settlement system," Shipley said. "We've already applied some of the lessons learned from Z2, so it's an incremental process. We still have to understand how we efficiently deliver projects."

"Communication is critical. Everyone has to be talking to each other," said SPP's engineering vice president, Lanny Nickell. "We tend to overcomplicate things, and we tend to be optimistic. We tend to set very aggressive schedules."

Shipley was reluctant to lay the blame on Symphono, which built a similarly customized system for MISO. He said because of SPP's larger footprint and "the way we settle," SPP needed "something different."

"I do think we underestimated some of the complexities of adding [other capabilities] to our systems," he said. "This vendor worked very hard with us. They made mistakes and missteps, but we did as well. We all bear some responsibility of where we were in February. We all bear the responsibility of the new timeline."

SPP

The project was approved two-and-a-half years ago with an estimated capital cost of $5.3 million. The implementation delay has not increased those costs, SPP said, but will likely result in additional maintenance costs because the existing settlement system and other legacy systems and software will run longer than planned.

FERC on Thursday granted SPP's request to defer several Tariff changes because of the settlement system's delay (*ER17-1568*). The Tariff revisions were filed because of changes to other systems as a result of the new settlement system. (See related story, "SPP Granted Delay for Tariff Revisions," *FERC Tells SPP to End Exit Fee for Some Members*.)

SPP Broadens PMUs' Reach with Revision Request

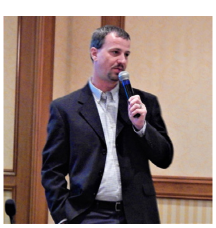
SPP will get another chance to widen the use of phasor measurement units (PMUs) within its footprint with the MOPC's approval of a revision request (RR) that addresses a FERC rejection of a previous RR.

RTWG RR340 changes the PMUs' installation location from the point of interconnection to the point of change of ownership and classifies equipment as "transmission owner interconnection facilities" to fully address cost responsibility. The RR also adds language to allow existing equipment to serve as a PMU.

"This just clarifies the cost issue and where [PMUs] will be installed," said American Electric Power's Richard Ross during the heat of discussion.

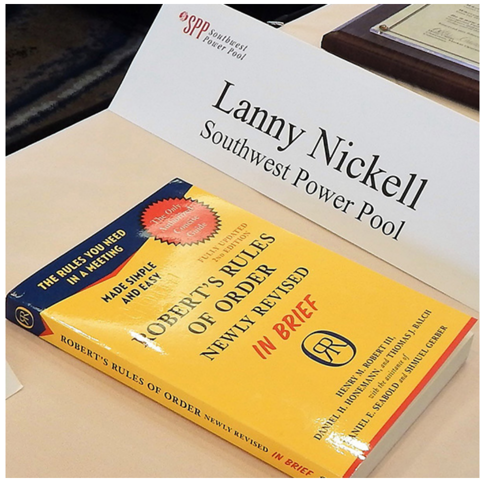
The recommendation was passed over two opposing votes and a half-dozen abstentions, primarily over installation costs.

RR340 is a response to a previous change request that would have required PMUs at new generator interconnections but was rejected by FERC in August. The RTWG said the commission found the language regarding the PMUs' installation funding unclear. The commission directed SPP to clarify how TOs will treat PMU installation costs to avoid including them in transmission rates. (See "Commission Rejects PMU Proposal over Cost Concerns," *3rd Time's a Charm for SPP Resource Adequacy Proposal*.)



Cody Parker | *© RTO Insider*

"This RR is trying to get in front so that we can capture more PMU data as it is brought on," said Cody Parker, SPP's supervisor of operations support.



MOPC's leadership abides by Robert's Rules of Order. | *© RTO Insider*

Parker said the RTO has completed the first phase of its *PMU project*, creating an informational-only system not used in real-time operations. Subsequent phases will be dependent on increased PMU coverage, he said.

SPP defines PMUs as monitors that provide precise grid measurements for synchrophasors. PMU measurements are taken at high speed, typically at 30 observations/second. Each measurement is time-stamped according to a common time reference, allowing measurements from different locations and utilities to be synchronized and combined to provide a precise and comprehensive view of the entire interconnection.

DER White Paper Gains Endorsement

The MOPC endorsed a Supply Adequacy Working Group *policy paper* that further defines the requirements for demand response programs and behind-the-meter generation and addresses whether to treat them as a load modifier or capacity.

The Distributed Energy Resources Policy is intended to ensure that all net peak demand is carrying the appropriate capacity, as required by SPP's resource adequacy requirements. SPP's Tariff allows a load-responsible entity to reduce its forecasted peak demand through DR programs and controllable and dispatchable BTM generation.

MOPC members debated the need to require DERs to attest to having firm transmission service to load, as the paper's draft required. Oklahoma Gas & Electric's Greg McAuley suggested the phrase "attest to having firm delivery to load" be used instead of "transmission service," which helped to gain approval against one dissenting and one abstaining vote.

"Some of the potential resources in [the controllable and dispatchable resource] category are behind retail meters and, as such, may never impact the transmission system and, therefore, would never need or have firm transmission service," McAuley explained.

The nine-page white paper, which has been approved by the SAWG and the Cost Allocation Working Group, will be turned into a business practice and eventually become an attachment to the Tariff's Attachment AA.

HITT Working to Finalize Report to Board

Suskie told the committee that the Holistic Integrated Tariff Team hopes to complete its yearlong work by the end of the month and present a final report to the Board of Directors for its April 30 meeting.

Composed of stakeholders, regulators and staff, the HITT has entered the third phase of its work in drafting and finalizing a report to the board. The team has been meeting since April 2018 to determine the optimal alignment of SPP's planning processes, cost-allocation methodologies, and market products and services. (See *SPP's Tariff Team Begins Carving up the Elephant*.)

"We remain positive we can get through the end of the month, but we have left the most contentious issue for last," said KCP&L's Buffington, referring to zonal transmission cost allocations.

"Like when the U.S. Constitution was drafted, there are a lot of different people on different sides," Golden Spread Electric's Mike Wise said. "I'm very optimistic that as a group, we are going to achieve what we set out to do, which is achieve value for members of the pool. Not everybody is going to be happy with it. I have compromised; Denise has compromised. I'm encouraged, very encouraged, where we are right now."

The HITT meets in Dallas on April 25 to complete the report. It has posted a *draft version* on its website.

MWG Proposal Improves RR Impact Analyses

The MOPC unanimously approved a recommendation by the Market Working Group and RTO staff to improve the RR process's impact analysis by revising the cost data that go into calculations.

SPP's Gary Cate said the new methodology

SPP

will provide a clear view of estimated vendor costs by no longer including capitalized costs, including those staff salaries that are already accounted for in the capital budget. The changes will also add transparency into staff time by adding the "true impact" to staff within the implementation timeline.

Staff costs will only include staff hours and remove redundant cost reporting between the capital and foundation budgets. Cate said the current method inflates staff cost by lumping average salaries into the cost of impact assessments.

With the change, impact analyses will provide a range of vendor costs rather than a single value with a rough order of magnitude +/- 50%.

Boston Marathoner Henderson Earns her Applause

Golden Spread's Natasha Henderson crosses the finish line. | *Natasha Henderson*

Members greeted Golden Spread's Natasha Henderson with applause when she joined the meeting, fresh off completing her second Boston Marathon the day before. Henderson battled unexpectedly warmer temperatures that slowed her pace, but she used a finishing kick to reach the finish line in just under four hours.

"I thought about dropping, but who drops out of the Boston Marathon? Not me," Henderson told *RTO Insider*. A personal best and qualifying for next year's marathon out of the question, she said, "this was now going to be a very long training run."

Henderson was scheduled to run a half-marathon in early June in Steamboat Springs, Colo., but has changed her registration to run the full 26 miles in an attempt to qualify for next year's Boston Marathon.

"Some days, like my second Boston Marathon, are not what I hoped they would be, but they make me stronger," Henderson said. "For me, running is about pushing myself and being a better person. I learned from the experience and hope to have another Boston Marathon in my future."

Members Pass 10 RRs on Consent Agenda

The MOPC unanimously endorsed its consent agenda, which consisted of 10 revision requests:

- *BPWG RR343*: Automates a manual task with installed software to prevent interchange overscheduling.
- *BPWG RR344*: Retires Business Practice 2500, which was implemented when the aggregate transmission service study could take years to complete. The study's methodology has been revised to include a six-month completion requirement, making the practice obsolete.
- *MWG RR346*: Includes transition major maintenance among the costs associated with start-up and no-load operations to be included in mitigated no-load and start-up offers beginning with the April 18, 2019, operating day.
- *ORWG RR338*: Expands and clarifies the description of "most severe single contingencies" and other potential contingency events used to determine the reserve sharing group's contingency reserve obligation.
- *ORWG RR349*: Requires responsible entities to use the reliability communications tool (R-comm) instead of telephones to communicate with the SPP balancing authority.
- *RTWG RR345*: Limits to three the number of identical transmission service requests impacting a DC tie during the submission window, as outlined in NAESB Business Standard WEQ 001-8.3.
- *RTWG RR347*: Removes grandfathered agreements that have expired or are no longer in service.
- *RTWG RR353*: Revises language in Tariff Attachment V to account for changes in *RR335*, which adds a three-stage generation interconnection study process and implements required changes in FERC Order 845-A.
- *STAFF RR351*: Clarifies and modifies the RR process requirements, allowing change requests to be withdrawn without requiring MOPC review and action. Any actions may still be appealed by qualified entities to the MOPC.
- *TWG RR350*: Eliminates language in the criteria that is already covered by NERC standards or other SPP standalone documents, minimizing inconsistencies or conflict with current and future NERC standards and revisions. ■

— Tom Kleckner

Company Briefs

EPSA Names Snitchler as next President, CEO

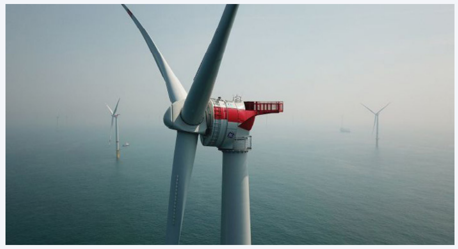
The Electric Power Supply Association board of directors Wednesday unanimously elected **Todd Snitchler** as the organization's next president and CEO. Snitchler will join the company on June 1 for a transitional period before officially beginning his duties July 1.

Snitchler was recently the vice president of market development at the American Petroleum Institute. Prior to that, Snitchler was in private law practice in Ohio. He is also a former chairman of the Public Utilities Commission of Ohio and a former member of the Ohio General Assembly.

He replaces CEO John Shelk, who has served in the role since 2005.

More: *Electric Power Supply Association*

GE Cedes French Offshore Wind Projects to Siemens Gamesa



General Electric Renewable Energy has ceded the rights to supply turbines for two French offshore wind farms potentially totaling nearly 1 GW to its rival Siemens Gamesa Renewable Energy.

GE said it is giving up its status as exclusive supplier to three offshore wind farms being developed by Eolien Maritime France (EMF) because delays since 2012 had "significantly impacted the financial characteristics of those projects."

The company said it remains committed to supplying its 6-MW Haliade 150 turbines to the first EMF project to clear longstanding authorization hurdles. EMF meanwhile confirmed it had selected Siemens to supply turbines "of similar dimensions" to the two remaining projects.

More: *Greentech Media*

Verizon Pledges to Go Carbon-neutral by 2035

Verizon announced Monday it will go carbon-neutral by 2035 for both its direct emissions and those from the purchase of energy.

To achieve its target, Verizon will need to significantly raise its current goal of 50% renewables by 2025. The wireless company also has a long way to go to reach that target: According to Jim Gowen, the company's chief of sustainability, on-site renewable generation now makes up less than 3% of the company's consumption.

Though Gowen declined to offer specific details about the company's coming clean energy commitments, he said more "significant" announcements are to come in the next year. But according to the company, because its 50%-by-2025 goal encompasses Verizon's entire operation — both its wireless and wireline businesses — the target "will allow us to more than cover 100% of Verizon Wireless' consumption."

More: *Greentech Media*

Federal Briefs

Bloomberg: Perry Planning Exit from DOE

Bloomberg reported that Energy Secretary Rick Perry is planning to leave the Trump administration and is finalizing the terms and timing of his departure, citing two people familiar with his plans.

While Perry's exit isn't imminent and one person familiar with the matter said he still hasn't fully made up his mind, three people said he has been seriously considering his departure for weeks, according to Bloomberg. All of the people spoke on condition of anonymity to discuss private deliberations.

Energy Department spokeswoman Shaylyn Hynes rejected the idea that Perry would be leaving the administration any time soon. "He is happy where he is serving President Trump and leading the Department of Energy," she said in a statement.

More: *Bloomberg*

DOE Announces $39M for Oil, Natural Gas R&D Projects

The Department of Energy last week announced up to $39 million in federal funding for cost-shared research and development projects that aim to improve oil and natural gas technologies.

The department will provide up to $15 million for projects that enhance the potential for enhanced oil recovery of conventional resources in offshore settings. It will also will provide up to $24 million for projects that support the development of tools, methods and/or technologies to cost-effectively enhance the safety and efficiency of natural gas production, gathering, transmission and storage infrastructure.

More: *Department of Energy*

Judge Rebukes Trump Policy to Increase Coal Mining on Federal Land

A federal judge late Friday delivered a significant setback to the Trump administration's policy of promoting coal, ruling that the Interior Department acted illegally when it sought to lift an Obama-era moratorium on coal mining on public lands.

The decision, by Judge Brian Morris of the U.S. District Court of the District of Montana, does not reinstate President Barack Obama's 2016 freeze on new coal mining leases on public lands. But the court ruling does say that the 2017 Trump administration policy, enacted by former Interior Secretary Ryan Zinke, to overturn the ban did not include adequate studies of the environmental effects of the mining, as required by the National Environmental Policy Act.

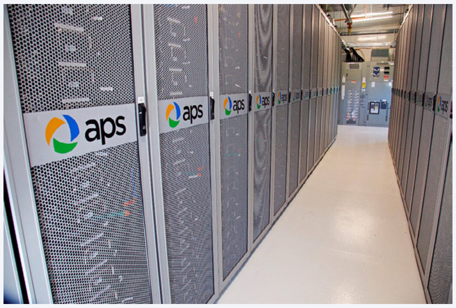
The judge also told the plaintiffs and defendants that in the coming months, he will put forth a second legal decision on whether the ban should be reinstated.

More: *The New York Times*

State Briefs

ARIZONA

Firefighters in Stable Condition After APS Battery Explosion



Four firefighters who were seriously injured from an explosion at an Arizona Public Service facility in Surprise are now in stable condition.

The firefighters were responding to a call about 6 p.m. Friday concerning smoke rising from the APS McMicken Energy Storage facility near Grand Avenue and Deer Valley Road. The facility contains a utility-scaled battery to store and distribute solar energy.

They were evaluating the lithium battery when there was an explosion that left them with chemical and chemical-inhalation burns. Annie DeGraw, a spokeswoman for APS, said the company didn't have any updates on what caused the fire or an estimate on how long the investigation would take.

More: *The Arizona Republic*

ILLINOIS

Pritzker Names New ICC Chair, Appoints New Commissioner

Gov. J.B. Pritzker last week promoted acting Commerce Commissioner **Carrie Zalewski** to chairman, succeeding departing Chair Brien Sheahan.

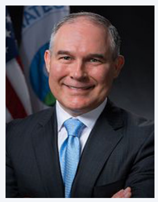
Zalewski was appointed to a five-year term on the commission last month and is awaiting Senate confirmation. She has served on the Pollution Control Board since 2009. Prior to serving on the board, she was assistant chief counsel for the state Department of Transportation. Sheahan will stay on as a commissioner until his term expires next year.

Pritzker also last week appointed Maria Bocanegra to a four-year term on the commission. She previously held the public seat on the Labor Advisory Board for the state Department of Labor. She also formerly worked as an attorney with Katz Friedman, where she handled workers' compensation and personal injury claims.

More: *Illinois Commerce Commission*; *Crain's Chicago Business*

INDIANA

Pruitt Registers as Lobbyist in State



Former EPA Administrator **Scott Pruitt** last week registered as a lobbyist with state regulators, identifying himself as a self-employed consultant and listing RailPoint Solutions as his sole client.

Pruitt listed his lobbying topics as "energy" and "natural resources." RailPoint Solutions does not appear to have a web address, nor is a company by that name registered to do business in the state.

The lobbying registration lists Heather Tryon as a responsible party. Heather Tryon is also the name of the CFO of Sunrise Coal, the state's second largest coal producer, according to the company's website.

More: *Indianapolis Star*

MICHIGAN

Developer Cancels Plan for Large Upper Peninsula Wind Project

Citing planning delays, global renewable energy developer Renewable Energy Systems has canceled plans for a wind project in the Upper Peninsula. The project called for 49 turbines spread over thousands of acres near the McCormick Wilderness area of the Ottawa National Forest.

The 130-MW Summit Lake Wind project had divided residents over its location near Lake Superior. The project in L'Anse Township northwest of Marquette was opposed by the local tribe for threatening hunting and fishing access. RES said the site was chosen for local wind availability, grid capacity, distance from residences and for its "compatible use of timberland."

More: *Energy News Network*

MISSOURI

House Considering Bill to Block Grain Belt Express

A month after the Public Service Commission deemed the Grain Belt Express transmission line in the public interest and granted the project a certificate of convenience and necessity, the House of Representatives gave initial approval to legislation last week that could effectively block developer Clean Line Energy Partners from using eminent domain to construct the line.

After the PSC's five commissioners granted unanimous approval to the line, House Speaker Elijah Haahr said he would make the passage of a bill forbidding eminent domain for the project a priority. The legislation, sponsored by Rep. Jim Hansen, would ban eminent domain "for the purposes of constructing above-ground merchant lines." The proposal still must win final approval in the House before moving to the Senate for consideration.

More: *St. Louis Post-Dispatch*

MONTANA

Colstrip Bill Easily Passes House

Senate Bill 331, otherwise known as the "Save Colstrip bill," easily passed the House of Representatives by a 62-38 vote last week. The bill would require state utility regulators to add an additional share of Colstrip Power plant debt to the rates of NorthWestern Energy customers should the utility increase its stake.

NorthWestern is attempting to increase its share in Colstrip Power Plant through a cheap purchase from one of the coal-fired asset's other owners and said it will increase its share of the plant only if the share can be had for $1, a term that's written into the bill.

The bill originally sidelined the Public Service Commission, establishing debts for NorthWestern customers that the PSC wasn't allowed to question. House lawmakers restored some PSC power to scrutinize Colstrip debts should NorthWestern acquire a larger stake in the power plant. The commission will be able to regulate the new costs for any added Colstrip share. The new debt would be added to the $407 million in depreciation costs customers are currently paying off for NorthWestern's 30% ownership in Colstrip Unit 4.

More: *Billings Gazette*

NEBRASKA

Legislature Advances Scaled-back Bill Aimed at Wind Energy

By a lopsided 40-1 vote, lawmakers have advanced a scaled-back bill that could make it harder to install transmission lines for use by privately developed wind farms on private property if landowners object.

A new version of the bill was passed after the original bill would have barred the state's public power organizations from using eminent domain. Opponents say that would have stifled wind energy development in the state. Senators reached a compromise, as the new version still allows for eminent domain but gives opponents a better opportunity to challenge projects in court.

More: *The Associated Press*

NEVADA

Sisolak Signs 50% Renewable Portfolio Standard

Gov. **Steve Sisolak** signed a bill on Monday increasing the state's renewable portfolio standard to 50% by 2030 after both houses of the legislature unanimously passed it last week.

The previous RPS held the state to 25% by 2025 and only applied to NV Energy. The new bill includes all retail electric providers in the state.

More: *Greentech Media*; *KTVN*

TEXAS

Austin Buys Troubled Power Plant for $460M

The city of Austin has purchased the Nacogdoches Generating Facility for $460 million as a way of getting out of the remainder of

a 20-year, $2.3 billion contract set to run through 2032. Austin Energy General Manager Jackie Sargent said the utility expects to save $275 million with the purchase.

Under a power purchase agreement with Southern Co., Austin Energy would have been responsible for escalating annual payments whether the city bought energy from plant or not. The payments, which were in the tens of millions of dollars each year, were expected to grow to $90 million in the contract's last year.

Austin Energy will issue taxable revenue bonds that will be paid out over 13 years to finance the purchase.

More: *Austin American-Statesman*