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PG&E: Bankruptcy Only 'Viable' Option

By Robert Mullin

Protesters stand with signs during Thursday's CPUC meeting in Sacramento. | © *RTO Insider*

A lawyer for Pacific Gas and Electric said the embattled utility did not file for bankruptcy to evade financial responsibility for wildfires that ravaged Northern California in 2017 and 2018, but to ensure the company is able to compensate the victims of those fires.

During a Thursday court hearing to review the numerous motions PG&E quickly submitted when it filed for Chapter 11 on Jan. 29, Attorney Stephen Karotkin said the company's move was intended to maintain its status as a going concern.

"Simply stated, your honor, there was no way for PG&E to finance its way through years of litigation and finance its business," Karotkin told U.S. Bankruptcy Court Judge Dennis Montali. "Chapter 11 is the only viable alternative."

During the half-day hearing, plaintiffs' attorneys urged the judge to create a claimant class for fire victims and asked him not to make their clients' claims subordinate to suppliers and other creditors.

The hearing was peppered with humorous remarks, a reflection of Montali's relaxed style even in the face of an extremely complex bankruptcy case involving the nation's largest utility.

Early in the proceeding, Karotkin assured the judge that, unlike in its 2001 bankruptcy during the Western Energy Crisis, PG&E was this time "seeking to work collaboratively" with the California Public Utilities Commission "to achieve a successful reorganization."

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Additional coverage pages 6-11

PJM: FERC Order Could Boost Default by $300M

Total GreenHat Loss May Exceed $430M

By Rich Heidorn Jr.

The cost of GreenHat Energy's default could rise by $250 million to $300 million if PJM is forced to unwind settlements of the company's financial transmission rights portfolio, PJM Chief Financial Officer Suzanne Daugherty said Thursday. That could push the total cost of the company's collapse to at least $430 million, Daugherty said.

PJM said it will seek a stay of FERC's Jan. 30 order rejecting a waiver of the RTO's liquidation rules and requiring it to resettle five months of FTRs that the commission said should have been liquidated sooner (*ER18-2068*).

In an email to members, Daugherty said the commission's ruling would have a dire impact on members and consumers.

"The waiver request was based on the legal vehicles and FERC precedents in effect to stop liquidation in an auction that was dysfunctional and which certainly would have resulted in unjust and unreasonable rates," she said.

FERC's order requires PJM to rerun the cleared July 2018 FTR auction and liquidate a "significant portion" of the FTR positions from the GreenHat portfolio for September 2018 through May 2019, PJM said. It also requires the RTO to unwind the default allocations and related settlements made for GreenHat FTRs that went to settlement since September 2018.

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LaFleur Announces Departure from FERC

Commissioner Cheryl LaFleur at the Independent Power Producers of New York's Spring Conference in May 2017, when she was acting chair of FERC. (p.5) | © *RTO Insider*

NERC Seeks $10M Fine for Duke Security Lapses

By Rich Heidorn Jr.

NERC has recommended a $10 million fine on an unidentified utility for repeated violations of critical infrastructure protection (CIP) reliability standards over more than three years that exposed a "lack of management engagement, support and accountability."

Energywire and *The Wall Street Journal* reported that the unnamed utility was Duke Energy, one of the nation's largest, with 7.6 million retail electric customers in six states and 49,500 MW of generating capacity. The company told the *Journal* it does not comment on enforcement filings.

In a *Notice of Penalty* filed Jan. 25, NERC cited

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In this week's issue

Meet RTO Insider's New PJM Correspondent

Christen Smith comes to *RTO Insider* after nearly a decade of pursuing tricky beats — from local tax disputes to state education funding to federal gun policy — preparing her well for the world of organized electricity markets. She graduated from Penn State in 2011 and lives in central Pennsylvania with her husband, two nearly-twin toddlers (born just 11 months apart) and two dogs.

FERC & Federal News

NERC Seeks $10M Fine for Duke Security Lapses

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127 violations between 2015 and 2018 (52 posing "minimal" risk, 62 "moderate" and 13 "serious"). While most of the violations were self-reported, others resulted from compliance audits.

Although many of the details were redacted as critical energy/electric infrastructure information (CEII), the document refers to "companies" and "regional entities" in the plural, suggesting a large, multistate utility was involved.

"The 127 violations collectively posed a serious risk to the security and reliability of the [bulk power system]. The companies' violations of the CIP reliability standards posed a higher risk to the reliability of the BPS because many of the violations involved long durations, multiple instances of noncompliance, and repeated failures to implement physical and cybersecurity protections," NERC said. "As an example, the companies' failure to accurately document and track changes that deviate from existing baseline configurations increased the risk that the companies would not identify unauthorized changes, which could adversely impact BES [bulk electric system] cyber systems."

The notice cited as contributing causes "disassociation of compliance and security that resulted in a deficient program and program documents, lack of implementation, and ineffective oversight and training."

The control room at Duke Energy's Buck combined cycle plant in Rowan County, N.C. | *Duke Energy*

Duke Energy Center, Charlotte, N.C. | *Duke Energy*

It also criticized "organizational silos" illustrated by a lack of communication between management levels and "a lack of awareness of the state of security and compliance."

There were also silos across business units "that resulted in confusion regarding expectations and ownership of tasks, and poor asset and configuration management practices," NERC said.

In a settlement, the companies agreed to pay the fine and to improve their performance by increasing senior leadership involvement and oversight; creating a centralized CIP oversight department; and restructuring roles to focus on standards, enterprise oversight, enterprise CIP tools, compliance metrics and regulatory interactions. They also agreed to conduct industry surveys and benchmark discussions to develop best practices.

The companies also agreed to invest in enterprise-wide tools for asset and configuration management, visitor logging, access management, configuration monitoring and vulnerability assessments; increase training; and institute annual compliance drills.

NERC said the penalty was based on the companies' "repeat noncompliance" and "deficient" compliance program, mitigated by the lack of evidence of any attempt to conceal the violations. The settlement and fines are subject to approval by FERC.

Among the most serious violations cited were:

- A failure to protect critical cyber asset (CCA) information. One-line diagrams lacked the appropriate NERC CIP classification markings and some employees were improperly granted "read-only" access to CCA information.
- A failure to follow its change control and configuration management process. In three instances, software upgrades were deployed on a single CCA in the production environment without first being tested as required by the change control process.

FERC & Federal News

- A failure to maintain annual cybersecurity training for some employees with electronic or physical access to CCAs.
- A failure to timely revoke former employees' and contractors' electronic access rights.
- Allowing individuals improper electronic access to CIP-protected information.
- Improperly configured routers that prevented monitor server logs from being sent to the security incident and event management (SIEM) device.
- A failure to monitor electronic security perimeter (ESP) inbound and outbound communications and to restrict inbound electronic access to ESPs. "The companies used overly broad ESP firewall rulesets, which permitted access across ports and services that were not required for operations or for monitoring CAs within the ESPs," NERC said. "Additionally, the companies failed to implement strong technical controls to ensure the authenticity of the accessing party for [redacted] individuals who were granted unauthorized access to the ESPs."
- Firewalls were configured to allow external remote access to sensitive systems without first going through an intermediate system, using encryption or requiring multi-factor authentication.
- A failure to implement physical access controls to limit unescorted access to the physical security perimeter (PSP) and failing to document all required information in visitor logbooks.
- Repeated failures to adhere to cybersecurity testing procedures, including deficient testing on software upgrades and failures to implement security patch programs.
- Failing to change passwords on annual schedule and failing to change factory default passwords for remotely accessible BES cyber assets.

NERC's filing came days before intelligence officials told the Senate Intelligence Committee on Jan. 29 that Russian hackers have the capability to disrupt electrical service in the U.S.

"Moscow is now staging cyberattack assets to allow it to disrupt or damage U.S. civilian and military infrastructure during a crisis and poses a significant cyber influence threat," officials said in the annual *Worldwide Threat Assessment*.

"Russia has the ability to execute cyberattacks in the United States that generate localized, temporary disruptive effects on critical infrastructure — such as disrupting an electrical distribution network for at least a few hours — similar to those demonstrated in Ukraine in 2015 and 2016. Moscow is mapping our critical infrastructure with the long-term goal of being able to cause substantial damage." (See *DHS: 2017 Russian Probes Hit Hundreds of Energy Cos.*)

The report also warned that China also "has the ability to launch cyberattacks that cause localized, temporary disruptive effects on critical infrastructure — such as disruption of a natural gas pipeline for days to weeks—in the United States." ■

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

PRIVILEGED AND CONFIDENTIAL INFORMATION HAS BEEN REDACTED FROM THIS PUBLIC VERSION

January 25, 2019

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: NERC Full Notice of Penalty regarding [redacted]
FERC Docket No. NP19-_-000

Dear Ms. Bose:

The North American Electric Reliability Corporation (NERC) hereby provides this Notice of Penalty regarding [redacted] with information and details regarding the nature and resolution of the violations[2] discussed in detail in the Settlement Agreement attached hereto (Attachment A), in accordance with the Federal Energy Regulatory Commission's (Commission or FERC) rules, regulations, and orders, as well as NERC's Rules of Procedure including Appendix 4C (NERC Compliance Monitoring and Enforcement Program (CMEP)).[3]

NERC is filing this Notice of Penalty with the Commission because [redacted]

[redacted]

[2] For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, alleged, or confirmed violation.

[3] *See* 18 C.F.R § 39.7(c)(2) and 18 C.F.R § 39.7(d).

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NERC Notice of Penalty
The Companies
January 25, 2019
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NERC Violation ID	Standard	Req.	VRF/ VSL	Applicable Function(s)	Discovery Method*	Risk
[redacted]	CIP-005-3a	R2.1, R2.2, R2.4	Medium/ High	[redacted]	SR	Serious
	CIP-005-3a	R2.2	Medium/ High		SR	Minimal
	CIP-005-3a	R2.5.3	Medium/ High		SR	Moderate
	CIP-005-5	R2; P2.1	Medium/ High		SR	Moderate
	CIP-005-5	R2; P2.1	Medium/ High		SR	Moderate
	CIP-005-5	R2; P2.1	Medium/ High		SR	Minimal
	CIP-005-5	R2; P2.1, P2.2, P2.3	Medium/ High		CA	Moderate
	CIP-005-5	R2; P2.1, P2.2, P2.3	Medium/ High		SR	Minimal
	CIP-006-3c	R1.1	Medium/ Severe		SR	Minimal
	CIP-006-3c	R1.5	Medium/ Severe		SR	Minimal
	CIP-006-3c	R1.6	Medium/ Severe		SR	Serious
	CIP-006-3c	R1.6.2	Medium/ Severe		SR	Minimal
	CIP-006-6	R1; P1.1	Medium/ Severe		SR	Minimal
	CIP-006-6	R1; P1.2	Medium/ Severe		SR	Serious
	CIP-006-6	R1; P1.4	Medium/ Severe		SR	Minimal
	CIP-006-6	R1; P1.8	Medium/ Severe		SR	Minimal

RELIABILITY | ACCOUNTABILITY

| NERC

FERC & Federal News

LaFleur Announces Departure from FERC

By Michael Brooks

LaFleur at the Independent Power Producers of New York's Spring Conference in May 2017, when she was acting chair of FERC. | © *RTO Insider*

Looks like this will be the last Super Bowl that Commissioner Cheryl LaFleur gets to wear her New England Patriots jersey at FERC headquarters.

LaFleur on Thursday announced she was "no longer seeking" a third term and would leave the commission by the end of the year.

LaFleur, who has served on the commission since July 13, 2010 — longer than all her colleagues' tenures combined — said she would stay until at least June 30, the end of her current term, "and probably longer, depending on my future plans and the possible appointment of a successor."

Senate leadership informed the commissioner last Tuesday that President Trump would not nominate her for another term, according to Andrew Holleman, LaFleur's communications and policy analyst. By law, she can stay on the commission past June 30 until a replacement is sworn in or until the end of the current session of Congress.

"She's said all along it wasn't her decision, so she figured she would make an announcement as soon as she heard," Holleman said in an email.

"While this is not the outcome I had hoped for, I feel very lucky to have served on FERC for more than eight years (and counting)," LaFleur said in a ***statement***. "It has been a high honor to serve at the commission, and I love working here. I have many people to thank for the opportunities I've had and will certainly have more to say as I get closer to actually leaving."

LaFleur declined further comment. A FERC spokesperson declined to comment.

With the departure of Robert Powelson in July and the death of Commissioner Kevin McIntyre on Jan. 2, FERC would be left with three commissioners after LaFleur's departure. A spokeswoman for Sen. Lisa Murkowski (R-Alaska), chair of the Senate Energy and Natural Resources Committee, said she has not heard anything from the White House regarding its plan for replacement nominees. Holleman also said he had not heard anything.

A Constant Presence

Nominated by President Barack Obama, LaFleur's tenure has been marked by frequent upheavals in the commission's roster.

She came to the commission after more than two decades in the electric and natural gas industry, including a stint as executive vice president and acting CEO of National Grid USA.

LaFleur became acting chair of the commission after the resignation of Jon Wellinghoff in 2013, and she was nominated by Obama for a second term in 2014. The president also nominated Norman Bay, then director of the commission's Office of Enforcement, as chair, but members of the ENR Committee protested, citing Bay's lack of regulatory experience and the gender politics of his ascension over LaFleur. This led to an unusual deal between the Senate and the White House, in which LaFleur became the chair for nine months while Bay served as commissioner. (See ***Senate Confirms Bay, LaFleur***.)

Bay took over the chair in April 2015. But he resigned shortly after Trump's inauguration in January 2017, when the new president named LaFleur acting chair again until a Republican could be sworn in. The GOP seats were empty after Philip Moeller and Tony Clark left the commission in October 2015 and September 2016, respectively.

Bay's resignation also left the commission without a quorum to issue orders and decisions, which would last for six months until the arrival of Republicans Neil Chatterjee and Powelson in August 2017. After the resignation of Colette Honorable in June 2017, LaFleur was briefly the lone commissioner.

The commission has been split along party lines for nearly a year over the consideration of greenhouse gas emissions in gas infrastructure approvals. Following an August 2017 ruling by the D.C. Circuit Court of Appeals that said FERC must consider the impact of greenhouse gas emissions when licensing gas pipelines, LaFleur has sided with fellow Democrat Richard Glick in voting against certain projects. (See ***Dem Dissents Show FERC Divide on Carbon***.)

With the departure of Powelson and the death of McIntyre after months of battling brain cancer that kept him from voting, Chairman Chatterjee has pulled gas items from the consent agenda at open meetings.

LaFleur's announcement brought accolades on Twitter.

"She epitomizes what public service is all about," Glick said.

"Her measured, fair and knowledgeable approach at FERC will be missed," said Theodore Paradise, senior vice president of transmission strategy for Anbaric.

"An exceptional servant and thoughtful leader who withstood one of the most trying and yo-yoing of any FERC tenure," said Dan Dolan, president of the New England Power Generators Association.

"She has been a tremendous role model to me and countless other women in the energy industry," said Shannon Maher Bañaga, director of federal affairs for TECO Energy. "'Thank you' isn't enough." ■

CAISO/WECC News

Make PG&E a Public Utility, Protesters Tell CPUC

By Hudson Sangree

SACRAMENTO, Calif. — Protesters at the Public Utilities Commission meeting on Thursday urged the commissioners to try to turn Pacific Gas and Electric into a publicly owned utility as part of its Chapter 11 bankruptcy that began when the company filed for bankruptcy protection Jan. 29.

"We have the opportunity to radically restructure what our energy system looks like — safe, public and one that ensures everyone the right to access," said Morganne Blais-McPherson, a University of California Davis student and co-chair of the university's Young Democratic Socialists of America chapter.

Unlike recent protests at PUC meetings in San Francisco, the Sacramento gathering was relatively tame. Demonstrators didn't disrupt the meeting or shout. They spoke only during public comment, mostly without going over the two-minute time limit set by PUC President Michael Picker.

The calm meeting capped off a tumultuous week of hearings and court filings involving PG&E and the PUC.

On Jan. 28, the PUC called a hasty and controversial meeting to allow PG&E to obtain billions of dollars in debtor-in-possession (DIP) financing to see it through bankruptcy.

The next day, just after midnight, the utility filed for bankruptcy in federal court in San Francisco. The first hearing in the bankruptcy case, which was mainly procedural, was held that afternoon. (See *PG&E Wants to Undo Contracts, Revamp Biz in Bankruptcy*.)

On Wednesday, a judge considered whether to impose stringent new conditions on PG&E for violating criminal probation in the 2010 San Bruno gas line explosion case, and the State Assembly held an oversight hearing of the PUC in which some lawmakers demanded that regulators do more to keep PG&E and other utilities from sparking deadly wildfires. (See related story, *Lawmakers Grill CPUC President on PG&E, Fires*.)

Another bankruptcy hearing started Thursday morning in San Francisco, about the same time the PUC was meeting in Sacramento. (See related story, *Judge Postpones Strict Probation Conditions for PG&E*.)

Seth Sanders, a member of the Democratic Socialists of America, said that as a parent and ratepayer, he has been upset to see PG&E seek bankruptcy protection when it is suspected of starting November's Camp Fire, which killed 86 people and destroyed the town of Paradise.

"I have been sick to my stomach," Sanders told commissioners. "This is a terrible insult to the memories of the dead."

Sanders and other protesters called for a restructuring of PG&E into municipal systems, citing the Sacramento Municipal Utility District as a good model. Their statements were met with quiet finger snapping from other demonstrators, some of whom stood holding signs.

(San Francisco officials have said publicly they might be interested in taking over PG&E's assets in the city and forming a municipal utility.)

At one point, protesters read aloud the names of about 40 fire victims, as they have done at other PUC meetings.

"Unless you do something, you're going to get us all killed," Robert Henderson told the commissioners during the public comment period.

Mary Kay Benson said she was from Chico, the neighboring town to Paradise in largely rural Butte County. Many of the dead were senior citizens, like her, Benson said.

"Are we all just corporate collateral?" she asked the commissioners.

Pete Woiwode, of Oakland, said he was at last Monday's raucous meeting in San Francisco, when the PUC approved PG&E's DIP financing with little public notice and over the objections of demonstrators.

"That should not have happened," Woiwode said. ■

Protesters at Thursday's CPUC meeting in Sacramento read aloud the names of those killed by wildfires. | © *RTO Insider*

Protesters listen to the CPUC proceedings during Thursday's meeting in Sacramento. | © *RTO Insider*

Mary Kay Benson, of Butte County, Calif., says many of those who died in the Camp Fire were senior citizens, like her. | © *RTO Insider*

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PG&E: Bankruptcy Only 'Viable' Option

Continued from page 1

"You don't think they were collaboratively engaged 18 years ago?" Montali asked, drawing laughter from the courtroom.

"I wasn't here 18 years ago, but from what I heard, I don't think so," Karotkin replied.

"I still have the boxing gloves," retorted Montali, who also oversaw that case.

'Comprehensive Review'

Stephen Karotkin | *Weil, Gotshal & Manges*

In his opening remarks, Karotkin told the court that PG&E decided to file Chapter 11 after a "comprehensive review" of its business, which confirmed the utility faced "a multitude of claims" from wildfire victims and "thousands yet to be filed." He noted about 50 complaints have already been filed against the company for November's Camp Fire, the costliest and deadliest fire in California history. The cause of the blaze is still under investigation.

Karotkin added that a recent finding by California fire investigators that PG&E equipment was not responsible for igniting the 2017 Tubbs Fire that destroyed part of the city of Santa Rosa did not significantly alter the company's precarious financial position. (See *PG&E Cleared in Fire that Burned Santa Rosa*.)

"The fact is, the comprehensive review fully took into account being exonerated for the Tubbs Fire," Karotkin said, adding that plaintiffs' lawyers "also think they have other theories to hold PG&E accountable" for that fire.

PG&E says its problems have been exacerbated by California's doctrine of inverse condemnation, which holds a utility strictly liable for property damage caused by a fire started by its equipment, regardless of whether the utility is found to have neglected maintenance.

The situation has left PG&E unable to access the capital needed to operate and service its debts, Karotkin said.

"PG&E believes Chapter 11 will more quickly and equitably address PG&E's liability than though the state court system," Karotkin said. One objective of the bankruptcy case would be to establish a trust fund for wildfire victims and restoration efforts, he told the judge.

Judge Dennis Montali | *Commercial Law League of America*

Fire Victims Seek Standing

But attorneys representing those victims expressed concerns that bankruptcy would force their clients to line up behind creditors and suppliers before they could collect on their claims.

Attorney Dario de Ghetaldi, a lawyer representing 1,500 claimants affected by the North Bay, Butte and Camp fires, asked that Montali not give debt and supplier payments priority over payments to plaintiffs that had executed pre-petition settlement agreements with PG&E over the Butte fire.

"There are other firms who have other Butte Fire plaintiffs in the same position, and I represent, I think, their views as well," de Ghetaldi said.

"We're obviously very sympathetic to his clients and the victims of these wildfires, and we understand their concerns, but we don't think it's prudent to risk the operations right now and risk potential recoveries for them going forward, which is why we think it's absolutely critical to maintain [PG&E's] operations and sustain them going forward," countered Karotkin's colleague, Matthew Goren.

Saying he represents "several thousand individuals who are now told they are creditors" of PG&E, San Francisco attorney Khaldoun Baghdadi asked the court to create a separate claimant class for fire victims.

"We feel that the voice that our clients represent is unique and central to resolution of these claims," Baghdadi said. "And with respect to the expeditious resolution [of the proceeding], I will just point to the court: In October 2017, several thousand people lost their homes and loved ones. Nearly every one of their homeowner insurance policies provided for two years of alternative living expenses, which means in October of this year, several thousand people are going to have a serious problem in finding a place to live."

Thursday's hearing may have also provided cold comfort to PG&E's many power suppliers, who have already beseeched FERC to intervene in any attempt by the utility to abrogate supply agreements. As part of its bankruptcy filing, PG&E asked the court to issue an injunction confirming its exclusive jurisdiction over the debtors' rights to reject power purchase agreements and other FERC-regulated contracts. (See *FERC Claims Authority over PG&E Contracts in Bankruptcy*.)

"Despite what has been written in the newspapers, there are not any motions on file at this time to reject any power purchase agreements or any other contract, and there is no current intention to file any of those motions in the immediate future," Karotkin said. "Those will be evaluated as the case progresses."

Karotkin's statement left unanswered the question of whether PG&E would seek to reprice PPAs with any of its power suppliers, as suggested in the utility's own filings with the bankruptcy court last Tuesday. (See *PG&E Wants to Undo Contracts, Re-vamp Biz in Bankruptcy*.)

Marc Sacks, a U.S. Department of Justice attorney representing FERC, said Thursday that FERC has agreed to give PG&E 60 days from its bankruptcy filing to respond to the agency's Jan. 25 order contending that the contracts fall under FERC's jurisdiction — and that it must sign off on any changes. That agreement extends the original Feb. 24 response deadline and also provides Montali enough time to rule on the injunction request.

By the end of the hearing, Montali had approved all 17 of PG&E's motions under review, noting the scattered objections to a few of them, including provisions related to bonuses in a motion covering employee compensation. All objections would be addressed by the final hearing, the judge said.

The next hearings in the PG&E proceeding are scheduled for Feb. 12 and 13, followed by an additional hearing two weeks later. ■

CAISO/WECC News

PG&E Wants to Undo Contracts, Revamp Biz in Bankruptcy

By Robert Mullin and Hudson Sangree

Philip Burton Federal Building, San Francisco | *U.S. Bankruptcy Court - Northern District of California*

PG&E Corp. and its subsidiary Pacific Gas and Electric Co. confirmed in *court papers* Jan. 29 the companies hope to rescind costly power purchase agreements and reform their obsolescent business model during a bankruptcy process that kicked off with a midnight filing for Chapter 11 reorganization. (See *PG&E Files for Bankruptcy*.)

In doing so, the utility giant *challenged* two recent rulings by FERC in which the commission said it shares authority with a bankruptcy judge in San Francisco to decide if wholesale power purchase agreements can be repealed or modified in the course of bankruptcy. (See *FERC Claims Authority Over PG&E Contracts in Bankruptcy*.) The first hearing before that judge last Tuesday gave some insight into how contentious that issue could become.

The stakes of that argument are high. PG&E said last Tuesday it has 387 power purchase agreements with 350 companies worth about $42 billion. Those PPAs represent 13,668 MW of contracted capacity, the utility said.

PG&E said it invested billions of dollars to help the state of California meet its renewable power obligations. Those investments drove down the cost of wind and solar energy for its competition, PG&E said, but left the company still paying for the more expensive contracts.

"As a result, many of the utility's agreements to procure renewable energy resources, which are typically long-term — 15- to 20-plus years in length, obligate the debtors at rates significantly higher than [those] currently available in the renewable resources market. On the contrary, other load serving entities, i.e., the debtors' competitors, are able to procure required renewable energy resources at those lower rates."

PG&E argued the only way for the companies to emerge from bankruptcy intact is for the court to allow the utility to abrogate overpriced contracts. It said any input from FERC over those contracts violates the court's authority under the Bankruptcy Code.

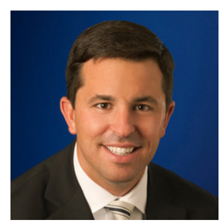
In its filing, PG&E notes "recent changes in the energy landscape have significantly" altered its energy procurement needs for the future.

"In recent years, there has been a significant decrease in demand for [PG&E's] electric supply service, which has resulted in [PG&E] providing less electricity to fewer customers," the utility wrote. Chief among the causes are the growth of community choice aggregators, direct access and distributed generation, as well as the success of energy efficiency programs.

"Due to the incontrovertible economic significance of the debtors' PPAs, as well as the continuously evolving competitive and regulatory factors affecting these agreements, the debtors' PPA rejection and assumption decisions under section 365 of the Bankruptcy Code will play a vital role in the reorganized debtors' post-emergence operations and financial profile," PG&E's lawyers wrote.

"As such, it is vital to a successful reorganization that the debtors' determinations regarding whether to assume or reject their PPAs be assessed by this court pursuant to the business judgment standard to which any other debtor is subject."

PG&E said it was primarily forced into bankruptcy by liability for massive wildfires in 2017 and 2018 that could top $30 billion. Wildfire victims and their advocates have argued PG&E was seeking bankruptcy protection to avoid their lawsuits, but PG&E insisted last Tuesday that wasn't the case.



Pacific Gas and Electric CFO Jason Wells | *PG&E*

"To be clear, the Chapter 11 cases are not a strategy or attempt to avoid PG&E's responsibility for the heartbreaking and tragic loss of life, devastating damage and destruction to homes and businesses, and harm to the communities that has been incurred as a result of the 2017 and 2018 Northern California wildfires," PG&E's chief financial officer, Jason Wells, wrote in a court declaration.

The thousands of victims who are part of the 750 lawsuits filed against PG&E will now likely assume a status similar to unsecured creditors.

Shareholders, meanwhile, will have to take their chances. Investors often lose their stakes in bankruptcy, but PG&E shareholders emerged largely intact after the company's 2001 bankruptcy in the wake of the state's energy crisis. Whether that happens this time is highly uncertain and probably will remain so for much of the next two years. One key difference: Unlike the previous bankruptcy that involved only the PG&E utility, this one covers its holding company as well.

14 Hours

The judge appointed to oversee the Chapter 11 proceeding in Northern California's U.S.

CAISO/WECC News

Bankruptcy Court pointed out that difference last Tuesday during the first hearing in what promises to be a drawn-out process. Judge Dennis Montali would know — in 2001 he was picked to oversee PG&E's prior reorganization.

Montali noted the sheer volume of the work already confronting his court.

"I want to repeat again something I made clear this morning ... most of us have only had 14 hours to absorb what has been filed," Montali said during the hearing.

The judge expressed regret that he wouldn't be able to address the 17 motions already filed in the docket or hear statements from those with an interest in the outcome of PG&E's bankruptcy.

"I'm trying to absorb everything quickly. I'm not going to listen to arguments [today]," he said.

Montali added he "feels very strongly" that the public be able to weigh in on such a "high-visibility" case but that he couldn't allow that during last Tuesday's hearings.

"I don't mean to be [discourteous] or cut off people otherwise, but I can't fit into the time frame anything," he said.

Instead, Montali kept the hearing focused on the procedural issue of "what comes next" — namely the schedule going forward — and addressing the most immediate concerns of the parties before the next hearing, now slated for Thursday at 9:30 a.m.

Montali said some of the motions in the docket didn't require immediate action, while pointing to a handful that do, including those related to maintaining current procedures around cash management, insurance policies, customer programs and employee wages. "The things that affect real people, like employees," he said.

But Montali promised his court would review all the motions during Thursday's hearing.

"The motions are fairly conventional, but the numbers are obviously much larger," said Stephen Karotkin, an attorney with Weil, Gotsal and Manges, which is representing PG&E. "I think we were very careful to tailor for a smooth transition into chapter 11."

At Karotkin's request, Montali issued orders temporarily granting the cash management request, as well as another motion intended to assure payments to natural gas and electricity exchange operators, such as CAISO.

Another Weil attorney noted PG&E was seeking a preliminary injunction confirming the bankruptcy court's exclusive jurisdiction over the debtors' rights to reject PPAs and other FERC-regulated agreements. He said the company would need the court to act on that matter before FERC's Feb. 25 deadline to respond to its Jan. 29 order on the issue.

"We don't think we need to be there. We need to be here," he said.

A Department of Justice attorney representing FERC piped up over the telephone: "The proceeding there is separate from the FERC one. FERC issued an order in its own jurisdiction. Nothing in this court could alter PG&E's statutory obligation to respond to FERC."

Montali urged PG&E's attorneys to do what they needed to comply with FERC's requirements until he ruled on the injunction. ■

Judge Postpones Strict Probation Conditions for PG&E

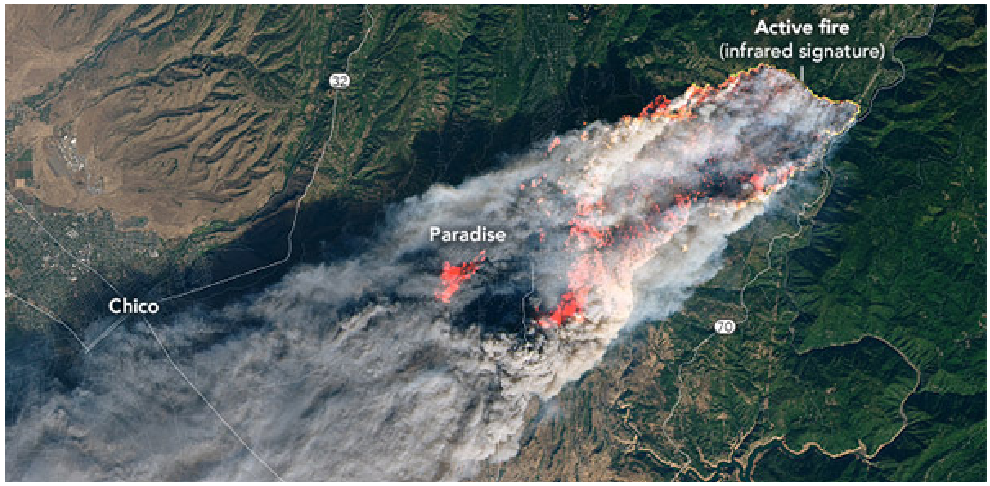
By Hudson Sangree

A federal judge on Wednesday delayed his decision to impose extensive new probation conditions on Pacific Gas and Electric in its criminal case for the 2010 San Bruno gas line explosion, including a requirement that the utility inspect its entire grid for safety problems before the start of this year's fire season.

Instead, Judge William Alsup, of the U.S. District Court for the Northern District of California, in San Francisco, said he would wait to the see the fire mitigation plan that PG&E files with the California Public Utilities Commission on Feb. 6, in compliance with last year's SB 901. The judge also asked lawyers representing both explosion and wildfire victims to submit more information on fire safety measures they discussed at Wednesday's hearing.

The hearing in the San Bruno case came a day after the utility and parent PG&E Corp. filed for bankruptcy, in part because they potentially face billions of dollars in liability for the fatal wine country fires of October 2017 and the Camp Fire in November 2018, which killed 86 people and destroyed the town of Paradise.

On Jan. 9, Alsup issued a tentative ruling in which he said that, unless the parties convinced him otherwise, he would impose new probation conditions on PG&E, which was convicted of six felonies for knowingly violating federal safety rules and obstructing a federal investigation after the 2010 explosion that killed eight people. (See *Judge, Governor, CPUC and Protesters Weigh in on PG&E Mess*.)



The Camp Fire killed 86 residents and wiped out the town of Paradise on Nov 8, 2018. PG&E equipment is a suspected cause. | *NASA*

Those new conditions would include requiring the utility to reinspect its entire grid in the coming months and to remove any trees or branches that could contact power lines. In addition, he said PG&E would have to "identify and fix all conductors that might swing together and arc due to slack and/or other circumstances under high-wind conditions."

The utility "shall identify and fix damaged or weakened poles, transformers, fuses and other connectors; and shall identify and fix any other condition anywhere in its grid similar to any condition that contributed to any previous wildfires," Alsup wrote.

"These conditions of probation are intended to reduce to zero the number of wildfires caused by PG&E in the 2019 wildfire season. This will likely mean having to interrupt service during high-wind events (and possibly at other times), but that inconvenience, irritating as it will be, will pale by comparison to the death and destruction that otherwise might result from PG&E-inflicted wildfires," the judge wrote.

PG&E protested the proposed conditions, saying it would cost between $75 billion and $150 billion to comply with the requirements. Federal prosecutors also encouraged the judge to back down and defer to the federal monitor overseeing PG&E in the wake of the San Bruno case. (See *PG&E Cleared in Fire that Burned Santa Rosa*.) ■

A section of the 30-foot gas pipeline owned by PG&E that exploded in 2010, killing eight people in San Bruno, Calif.

CAISO/WECC News

Lawmakers Grill CPUC President on PG&E, Fires

By Hudson Sangree

SACRAMENTO, Calif. — Public Utilities Commission President Michael Picker told lawmakers Wednesday the commission probably isn't the best public entity to address the "enormity" of the state's recent wildfire crisis.

The PUC has been trying to help prevent wildfires sparked by electric utilities, as required by last year's SB 901. But the commission, Picker said, is more like a specialized court that sets utility rates, not a fire prevention agency such as the Department of Forestry and Fire Protection.

"They understand fires. We understand ratemaking," Picker told the Assembly Utilities and Energy Committee during its annual oversight hearing of the PUC.

He said the commission was set up long ago to slowly gather and weigh evidence on regulated utilities, not to react quickly to urgent public safety matters.

"I don't think this is where you're going to get a sense of urgency," Picker said later.

Picker's briefing on the PUC's varied activities quickly turned into a sometimes tense discussion of wildfires and Pacific Gas and Electric, which filed for bankruptcy Jan. 29. (See *PG&E Files for Bankruptcy*.) Some lawmakers were cordial with Picker, while others grilled him about what the commission was doing to prevent more devastating wildfires like the deadly ones that ravaged the Northern California in the past two years.

Officials of the California Public Utilities Commission listens to lawmakers critique their handling of the state's wildfire crisis at an oversight hearing Wednesday. | © *RTO Insider*

"We're well over 100 deaths in these fires," said Assemblymember Jim Wood (D), whose North Coast district was heavily scarred by the wine country wildfires of 2017. "What will you do this year to protect Californians?"

Picker said the PUC had been in the process of figuring out what to do with PG&E, including breaking up the company or replacing its board members.

Financial penalties, including a $1.6 billion fine after the San Bruno gas line explosion in 2010, had failed to change the company's board members or safety culture, he said.

"Fines are just not enough," Picker said.

Now those decisions likely will be made by a federal bankruptcy judge, with the PUC recommending a reorganization plan for PG&E, he said.

"We will contend with them as advocates for ratepayers in bankruptcy," Picker said.

Earlier this month, a federal judge overseeing PG&E's criminal probation in the San Bruno case said he might require the utility to inspect every inch of its grid before the 2019 fire season starts this summer. The judge backed off on that plan, at least temporarily, in a hearing in San Francisco earlier Wednesday. (See related story, *Judge Postpones Strict Probation Conditions for PG&E*.)

Picker said the PUC had looked at what it would take for it to inspect the state's high-risk fire areas for overhanging branches and other safety problems. He said the commission would need to hire between 15,000 and 20,000 workers to inspect 4.2 million power poles and 200,000 miles of transmission lines.

A better investment, he said, would be for utilities to adopt extensive weather monitoring, as San Diego Gas & Electric did in Southern California. The National Weather Service typically estimates wind gusts on ridgetops. Fires start near electric lines in canyons down below. SDG&E deployed an extensive network of weather stations and cameras in such locations, Picker said. (See *Calif. Regulators to Scrutinize De-energization*.)

"They had to develop a whole new weather system within their service area," and PG&E could do the same in Northern California, he told committee members.

Assemblyman Bill Quirk (D) suggested the PUC had been partly responsible for driving PG&E into bankruptcy. SB 901 tasked the commission with performing a stress test to determine how much a utility could pay in wildfire liability without harming ratepayers or undermining grid reliability. The rest would have to be paid by shareholders.

Creditors wanted to know the extent of PG&E's expected liability, Quirk said. The utility must borrow $2 billion a year, and the PUC's inability to provide creditors with more certainty had led major ratings firms to downgrade PG&E's creditworthiness to junk status and cut off its access to credit, he said.

Picker said the PUC couldn't supply a stress-test figure until all official fire investigations have concluded and it performs its own analysis, which could take 18 months. "We don't know the cost in the end," he said. ■

During a Legislative oversight hearing Wednesday, Assemblywoman Eloise Gomez Reyes (D), right, asked PUC President Michael Picker, left, why more wasn't being done to prevent wildfires sparked by electric utilities. | © *RTO Insider*

ERCOT News

ERCOT Technical Advisory Committee Briefs

TAC Endorses Granularity to Ancillary Services Products

ERCOT stakeholders last week moved to address the Texas grid's growing pains by tweaking the system's ancillary service offerings, which predate the switch from a zonal to a nodal market in 2010.

The Technical Advisory Committee on Jan. 30 endorsed a Nodal Protocol revision request (*NPRR863*) that modifies responsive reserve service (RRS) to become primarily a frequency response service, allowing resources to earn compensation for providing primary frequency response (PFR). It also creates a new ERCOT contingency reserve service (ECRS), providing the grid operator with more "granular tools" to resolve low inertia levels caused by the changing resource mix.

Electranet Power's Marty Downey, representing the Independent Retail Electric Providers segment, pointed out that while wind energy and other renewables increase their presence in the ERCOT market, the ancillary services' design has remained the same.

"Our grid has changed dramatically," he said. "Wind energy continues to put pressure on ERCOT to address lower inertia. This gives ERCOT the tools to address that."

South Texas Electric Cooperative (STEC), which sponsored the revision request, said RRS has been a staple of ancillary service offerings since the beginning of the zonal market. Its two components — PFR and 10-minute energy deployment — reflect the thermal generation technology available when the market opened, STEC said.

The co-op noted that NERC reliability standards require ERCOT's online resources to provide PFR unless exempted by the grid operator. The system's generation resources end up "providing an uncompensated service … and are subject to compliance risk" regardless of whether they have an RRS responsibility at the time, it said.

STEC also said ECRS provides ERCOT with additional flexibility while also "liberating" the 10-minute component from RRS. The co-op said creating two distinct ancillary service products removes barriers to entry, creates market efficiencies and appropriately compensates resources for the services they provide.

The Advanced Power Alliance's (formerly The Wind Coalition) Walter Reid supported the NPRR. "Our members are all developing bat-

The TAC gathers for its January meeting.

teries and solar," he said, pointing to more than 2 MW of energy storage in ERCOT's interconnection queue.

"This is going to happen. We need to do things to facilitate this happening," Reid said, calling for the revision request's quick implementation.

As proposed, fast frequency response will be implemented in 2020 and ECRS no earlier than Jan. 1, 2022.

Stakeholders rejected a suggestion from industrial consumers, uncomfortable with the bifurcated approach and $2.5 million to $3.5 million in costs, to move implementation back to 2021 and 2022, respectively. An amended motion failed on a roll-call vote, gaining only 36% support.

The motion to endorse NPRR863 passed by an 86-14 margin. Luminant Generation, Reliant Energy Retail Services and industrial consumers voted against the measure.

Luminant's Ian Haley

"The market does need certainty," said Ian Haley, director of ERCOT regulatory policy for Luminant. "We have a fleet of generation resources that need to know what to provide. Having uncertainty seems scary to someone in our position."

"We're going to add a lot more renewables this year and next year. Inertia is going to be low," said Sandip Sharma, ERCOT's manager of operations planning. He said the grid operator hit 127 MW of inertia in 2018, its lowest level ever.

Luminant's Ian Haley

"ERCOT has been waving the inertia flag for several years. We're on the cusp of that," STEC's Clif Lange said. "Now's the time. … Holding off on PFR only increases the cost to consumers."

Members Approve Urgent Battery Request

The committee accepted an urgent revision request that will allow Luminant to operate an energy storage system in West Texas, without setting requirements for future storage facilities.

NPRR915 defines batteries and other limited-duration resources and clarifies how their qualified scheduling entities should indicate to ERCOT their unwillingness to be deployed in real time, thus reserving the capacity for expected values above the energy-offer curve.

The measure, sponsored by Luminant, passed with one abstention.

Haley said as Luminant developed its 9.9-MW Upton 2 energy storage system, which *became operational* Dec. 31 south of the Midland-Odessa region, it became apparent the generator would have to register the battery under requirements not currently defined in the protocols. Upton 2, the largest storage project

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in Texas, was designed as a settlement-only resource, but it would have been required to register as a "capital G" generation resource.

Haley noted that while Luminant can update market offers from the battery, the fully charged resource will only last 4.5 hours when pushing its full capacity onto the grid, possibly leaving it "completely deployed and drained before those offers can take effect. This clarifies how we are supposed to let ERCOT know, 'Please do not deploy the battery for the next [security-constrained economic dispatch] run.'"

Haley described NPRR915 as a one-off until ERCOT can get a handle on how to better accommodate battery storage systems.

"This shouldn't apply to all batteries until we have a holistic view on all of this, but we should have a way for our battery to operate," he said.

ERCOT said it plans to hold one or two workshops addressing energy storage issues, likely following the March spring break season. TAC Chair Bob Helton, of ENGIE, said the workshops will help determine whether to create a task force or turn the work over to stakeholder groups.

"We're going to need a couple different set of rules for how batteries are operated, rather than shoehorning them into our existing software," Reliant Energy Retail Services' Bill Barnes said. "We encourage ERCOT to move forward [with the workshop] and get rules in place that make sense."

ERCOT Director of System Planning Warren Lasher committed to previewing with the TAC at its next meeting a list of issues to be discussed during the workshops.

Reid was among several stakeholders urging ERCOT to hold the workshops as soon as possible. He reminded the committee that storage facilities are currently being registered in the market.

"The toe is in the water and batteries are hitting the ground, so the iron is getting ahead of the paper," he said.

ERCOT's RUC Activity Up over 2017

Staff's annual review of reliability unit commitment (RUC) activity indicated a 14.2% increase over 2017, much of it to help resolve local issues with high load in the Permian Basin.

ERCOT's 642 instructed resource hours in 2018 resulted in 613 effective RUC resource-hours, as compared to 562 and 534, respectively, for 2017. Staff said 22% of the effective resource-hours were bought back, resulting in a total RUC make-whole amount of about $460,000.

More than half of the total resource-hours came during the first half of May in the Permian Basin, where oil and gas production continues to drive much of the load.

In a separate required report, ERCOT's Sean Taylor said the grid operator's forecasted system administration fee of 55.5 cents/MWh for 2020 and 2021 will be "adequate." Taylor said staff will provide an update when the commission weighs in on how it intends to fund real-time co-optimization.

Members Re-elect Helton, Coleman to TAC Leadership

The TAC re-elected Helton as chair and the Texas Office of Public Utility Counsel's Diana Coleman as vice chair for 2019.

The members also confirmed the leadership of its Protocol Revision (Chair Martha Henson, Oncor, and Vice Chair Melissa Trevino, Occidental Chemical), Reliability and Operations (Chair Kevin Bunch, EDF Energy Services, and Vice Chair Tim Hall, Southern Power), and Wholesale Market (Chair David Kee, CPS Energy, and Vice Chair Resmi Surendran, Shell Energy) subcommittees.

The Retail Market Subcommittee's leadership will be confirmed at the TAC's next meeting.

TAC Endorses PUC's Changes to ORDC

Responding to a January directive from the Texas Public Utility Commission, the committee endorsed an Other Binding Documents revision request (*OBDRR011*) that modifies ERCOT's operating reserve demand curve (ORDC), which provides a price adder during periods of generation scarcity. (See *Texas PUC Responds to Shrinking Reserve Margin*.)

The change shifts the ORDC's loss of load probability (LOLP) curve by 0.25 standard deviations in 2019 and by the same measure in 2020. The use of a single blended ORDC curve is expected to lead to its more frequent use, and at higher levels.

The commercial and industrial consumer segments abstained from the vote. So did Direct Energy's Sandy Morris, who said she continues to have concerns about consolidating the curves.

In "respectfully" abstaining, Thompson & Knight attorney Katie Coleman, representing the Texas Industrial Energy Consumers, noted her association's longstanding opposition to the change and its potential increased costs.

"We're still not in favor of it," Coleman said. "In addition to not being comfortable with the magnitude of the shift, we're also uncomfortable with combining the curves. It amplifies the pricing impacts."

The PUC asked staff to provide to the commission a high-level implementation plan and timeline during its Feb. 7 open meeting. The grid operator is planning a March implementation.

The TAC also endorsed *NPRR871*, which had previously been tabled. The revision request gives ERCOT a mechanism to conduct a reliability review of customer- or resource-funded transmission projects, but without providing a recommendation.

"We don't want the review process short-circuited by the project's source of funds," said STEC's Lange, who helped supply the NPRR's final language.

Jeff Billo, ERCOT's senior manager of trans-

TAC Chair Bob Helton and ERCOT COO Cheryl Mele

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mission planning, told stakeholders the grid operator would follow its normal study process in conducting the review, which would take 90 to 150 days. Billo said should staff identify a reliability or congestion problem, ERCOT would have the authority to recommend the project not proceed.

The TAC approved six other NPRRs, a second OBDRR and two Retail Market Guide changes (RMGRR):

- *NPRR850*: Lays out principles for ERCOT and market participants to follow during a market suspension and restart and how activities will be settled.
- *NPRR886*: Requires ERCOT, to the extent possible, to provide notice and allow time for comments before executing any new or amended agreement with another control area operator.
- *NPRR905*: Provides resettlement to reflect the proper distribution of the congestion revenue right balancing account.
- *NPRR907*: Replaces the M1a component of the total potential exposure calculation with a value that can vary based on non-banking business days and ERCOT holidays following the specific operating day. The M1a component sets a time period reflecting the number of days between an operating day and the beginning of a mass transition of the market participant's electric service identifiers.
- *NPRR910*: Codifies eligibility, pricing and settlement for a resource that has been awarded a three-part supply offer in the day-ahead market but decides not to operate in the real-time market and subsequently receives an RUC instruction.
- *NPRR911*: Reinstates previous language in the applicable protocol sections for determining online combined cycle generation resources' (CCGRs) logical resource nodes' real-time LMPs, following *NPRR890*'s approval. The LMPs will now be based on their weighted average at the resource node for each of the generation resources in the online CCGRs, using their real-time telemetered outputs to calculate the weight factor.
- *OBDRR010*: Codifies that the high sustained limit will be included in the ORDC pricing's online capacity for resources that have been awarded a three-part supply offer in the day-ahead market, but decide not to operate in the real-time market and subsequently receive a RUC instruction. Related to NPRR910.
- *RMGRR156*: Moves ERCOT-specific market communication responsibilities to the Business Practice Manual while retaining retail-specific market communications and processes in the RMG.
- *RMGRR157*: Allows transmission and/or distribution service providers to give an internet-based solution for safety-net submittals. ■

— Tom Kleckner

ISO-NE News

FERC Rejects NEPOOL Press Membership Ban

Narrow Ruling Leaves Transparency Issue in Question

By Rich Heidorn Jr.

Many of NEPOOL's meetings are held at the Westborough, Mass., DoubleTree Hotel. | *Google*

FERC last week rejected the New England Power Pool's attempt to bar members of the press from membership but left intact — for now, at least — rules barring reporting on proceedings (*ER18-2208-001*).

The commission's unanimous Jan. 29 ruling appears to open the way for *RTO Insider* reporter Michael Kuser to join NEPOOL. But without additional action by the commission, he would be bound by NEPOOL's rules barring members "from reporting on deliberations or attributing statements to other NEPOOL members."

The commission said it would be ruling separately on *RTO Insider's* Section 206 complaint asking it to terminate the group's stakeholder role or direct ISO-NE to adopt an open stakeholder process like those used by other RTOs (EL18-196). 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.

NEPOOL filed the request to bar members of the press from joining after Kuser, an electric ratepayer in Vermont, applied to join as an End-User Customer in March.

The group said the rule change was necessary because allowing the press to join would inhibit its ability to foster candid discussions and negotiations that narrow and resolve complex issues. NEPOOL also contended FERC had no jurisdiction to reject the rule change.

Unduly Discriminatory

FERC said, however, it did have jurisdiction, and the proposed change was unduly discriminatory.

"The NEPOOL press amendments deny NEPOOL membership to members of the press who serve any role directly connected with news collection and reporting. Because some such members of the press otherwise would be eligible for NEPOOL membership as end-use participants, this prohibition unjustly denies them the ability to vote on NEPOOL matters despite their stake in the outcome," the commission said.

"NEPOOL's primary argument in support of excluding the press from NEPOOL membership relates to concerns with the reporting of stakeholder discussions. We find, however, that the record does not support the contention that allowing members of the press to become participating NEPOOL members will inhibit NEPOOL's operations or undermine stakeholder deliberations. The Participants Committee Bylaws and Standard Conditions currently in place — which this order does not affect — already prohibit all NEPOOL members from reporting on deliberations or attributing statements to other NEPOOL members. NEPOOL has not demonstrated that barring members of the press from exercising the privileges unique to NEPOOL membership — i.e., attending, speaking and voting at NEPOOL meetings — will meaningfully advance its aim for candid deliberation in light of these existent provisions. The NEPOOL press amendments do, however, as discussed above, prevent the participation of individuals otherwise eligible for membership solely based on their profession."

[Editor's Note: Kuser and *RTO Insider* told NEPOOL officials his application was intended to provide him a means to cover stakeholder meetings, and he did not intend to take policy positions or vote.]

Jurisdiction

FERC said NEPOOL's membership rules were within the commission's jurisdiction because they directly affect commission-jurisdictional rates, noting that the group's votes "both signal to the commission stakeholder approval of ISO-NE proposals and have the potential to generate alternative 'jump ball' proposals for commission consideration."

The order said it was acting consistent with commission precedent. "The commission has found that the stakeholder process within an RTO/ISO 'is a practice that affects the setting of rates, terms and conditions of jurisdictional services of the type that the Supreme Court has held falls within the commission's jurisdiction,'" it said, quoting from a 2016 order involving PJM.

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Remaining Questions

The commission's ruling gave no indication how, or when, it will rule on *RTO Insider's* complaint, which was filed two weeks after NEPOOL's proposed rule change.

RTO Insider contended nonpublic meetings violate the public interest and the missions stated in ISO-NE's and NEPOOL's governing documents.

It also contested NEPOOL's assertion that it is a private organization, saying FERC precedent "hardwires the NEPOOL stakeholder process into the regulatory process by requiring its use."

RTO Insider said if the power pool can justify its press ban as a "private" entity desiring secrecy, "its special powers and privileges should be transferred to an open stakeholder process within ISO-NE, and the ISO-NE resources devoted to NEPOOL (currently $2.6 million annually) should be devoted to an open stakeholder process within ISO-NE."

Reaction

"An occasion for dancing in the streets!" tweeted New Hampshire Consumer Advocate D. Maurice Kreis, who had opposed the ban.

Another opponent of the ban, Tyson Slocum, director of Public Citizen's Energy Program, was less jubilant, calling it "a partial victory for the public and the freedom of the press."

"It is outrageous that, despite today's FERC order, NEPOOL is still free to ban the general public from attending meetings, and journalists cannot attend meetings unless they pay a membership fee. FERC-jurisdictional proceedings, where billions of dollars in electric rate policy are developed, must be freely open to the public and the media," he said.

Miles Farmer, an attorney for the Natural Resources Defense Council, said the ruling is important "because NEPOOL's deliberations affect New England customers' energy prices as well as the mix of technology types that supply the region."

"ISO New England is the only regional grid operator that has closed its door on press access to its stakeholder meetings — meetings where key decisions are made about the Northeast's electricity supply," said Mike Jacobs, senior energy analyst at the Union of Concerned Scientists, which had opposed the NEPOOL proposal. "The need for public debate and awareness of pending energy decisions is of paramount importance as a society faces a changing climate. It's good to see FERC cast a vote against this proposal and in favor of a little more transparency and accountability in New England's power planning process."

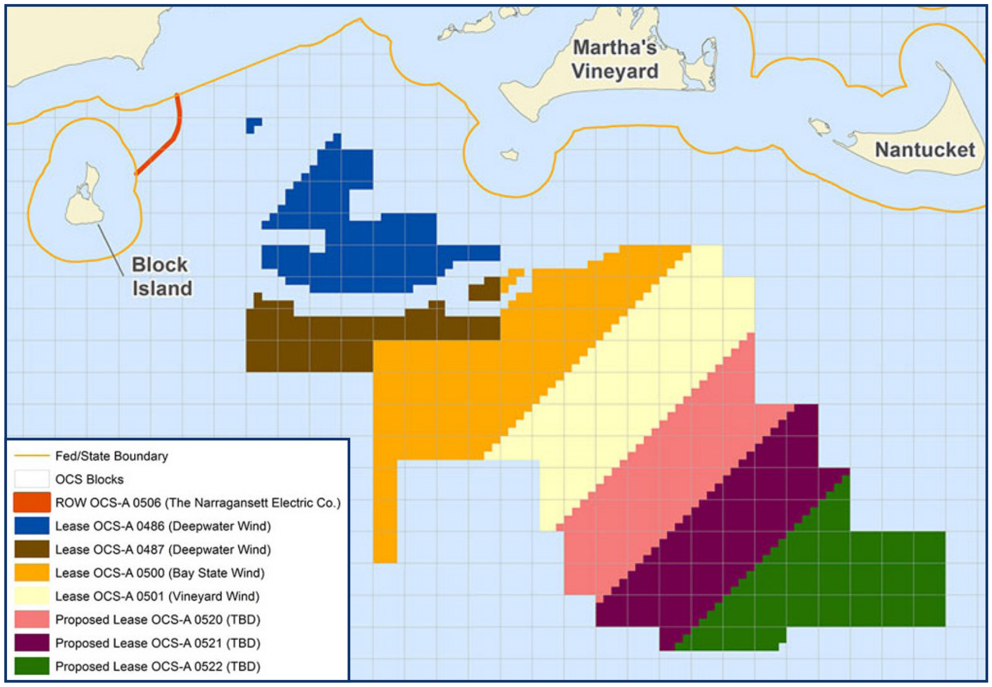
NEPOOL Chair Nancy P. Chafetz, the New England director of market intelligence for Customized Energy Solutions, did not immediately respond to a request for comment.

NEPOOL Secretary David Doot responded to the order with a memo to members, saying "the Membership Subcommittee will meet to consider the pending application from the *RTO Insider* press reporter and recommend to the Participants Committee whether any additional conditions should apply to such a membership." ■

ISO-NE News

Vineyard Wind Files Emergency Motion to Stay ISO-NE Auction

By Michael Kuser



BOEM Mass Rhode Island leases: A chart from the Bureau of Ocean Energy Management shows wind energy lease areas offshore Massachusetts and Rhode Island. | *BOEM*

Vineyard Wind on Monday filed an emergency motion for FERC to stay ISO-NE's 13th Forward Capacity Auction, claiming it "will suffer irreparable injury" if it is not afforded renewable technology resource (RTR) status in the auction, which was scheduled to begin the same day the company submitted its request (*ER19-570, ER19-444*).

Resources obtaining RTR status are exempted from the auction's minimum offer price rule (MOPR).

The Feb. 4 motion came after the commission failed to act on Vineyard's Dec. 14 *request* for waiver of ISO-NE Tariff provisions requiring that the RTR exemption be granted only to resources within the borders of a New England state. FCA 13 covers the capacity commitment period from June 1, 2022, to May 31, 2023.

Commissioners Cheryl LaFleur and Richard Glick issued a joint *statement* Feb. 4 saying, "We are disappointed that the commission failed to act on Vineyard Wind LLC's requests for a waiver and emergency motion in advance of ISO New England's forward capacity auction. We recognize that the commission can move forward only when it has a majority of votes for a particular action. Nevertheless, by failing to act, the commission has introduced significant uncertainty into this auction. All parties, including New England's states, consumers and auction participants, deserve better."

Vineyard cited "extraordinary circumstances" in requesting the stay, or in the alternative, that the commission vacate the results of the auction and permit a new auction to occur as soon as practicable after action on the company's petition.

Bloomberg *quoted* RTO spokesman Matthew Kakley as saying, "The auction is already underway. A delay would be unfair to the hundreds of other market participants."

The company also requested that "the commission follow the path it used in addressing the requests for declaratory order in advance of the expected bankruptcy filing of Pacific Gas and Electric Co. and establish a one-day comment period and issue an order on the merits promptly thereafter." (See *FERC Claims Authority over PG&E Contracts in Bankruptcy*.)

A joint venture by Iberdrola and Copenhagen Infrastructure Partners, Vineyard last May won a contract to supply Massachusetts with 800 MW of offshore wind energy, and in December won another lease area off Martha's Vineyard in an auction conducted by the Bureau of Ocean Energy Management. (See *Mass. Offshore Lease Auction Nets Record $405 Million*.)

'Plain Vanilla'

In a Jan. 29 order, the commission accepted the RTO's Tariff revisions to support implementation of the Competitive Auctions with Sponsored Policy Resources (CASPR) rules, which the commission accepted in March 2018 (*ER19-444*). (See related story, *FERC Clarifies ISO-NE Generator Delist Bid Rights*.)

But in a partial dissent, Glick said the RTO adopted a "confounding interpretation of what qualifies as a state-sponsored resource" by concluding that an offshore wind facility procured in a state solicitation does not qualify as a state-sponsored resource for the purpose of the RTR exemption to the MOPR, which CASPR retained as a transition mechanism to the fully fledged substitution auction.

In comments filed Jan. 4, the RTO said it "does not oppose" Vineyard's request for waiver, noting that it adopts the approach outlined in the filed Tariff revisions, including the request that, if the RTR cap is reached, the proration provisions will only apply to resources that, similar to Vineyard, seek RTR treatment under revised rules.

Vineyard said it filed its original waiver request "in good faith" in accordance with longstanding FERC processes.

"The timing of the petition was well within the commission's accepted time frames," the company said. "Market participants rely on FERC to address this type of plain vanilla filing ... on the merits and in a timely fashion. Up until now, the commission has always done so. In Vineyard Wind's understanding, this situation is unprecedented."

The Massachusetts Department of Energy Resources on Feb. 1 filed *comments* supporting Vineyard's original petition, saying that the company's contracts with it "represent over a year's worth of collaboration and consultation" and are "a significant milestone" in the state's "transition to a clean, diversified energy portfolio."

Gov. Charlie Baker also sent a *letter* last week asking the commission to approve Vineyard's request for a limited Tariff waiver, reiterating the department's point that "the total direct and indirect benefits to Massachusetts ratepayers from the long-term contracts with Vineyard Wind are expected to be approximately $1.4 billion." ■

ISO-NE NEWS

FERC Clarifies ISO-NE Generator Delist Bid Rights

Commission also Accepts CASPR Tariff Revisions

By Michael Kuser

FERC last week clarified on remand that a capacity supplier's retirement bid can enter ISO-NE's Forward Capacity Auction if the supplier demonstrates that the bid is just and reasonable, despite contrary assertions by the RTO's Internal Market Monitor (*ER16-551-004*).

The D.C. Circuit Court of Appeals on Dec. 28 remanded back to the commission its original October 2017 order accepting ISO-NE's retirement delist bid mechanism in the FCA (Exelon v. FERC, 17-1275). The court's action was based on the commission's own explanation at oral argument that a market participant — and not ISO-NE or the Monitor — has the right to show that its filed rate is just and reasonable and will be entered into an auction regardless of the Monitor's proposed offer price (*ER16-551-003*). FERC had until Feb. 1 to respond.

"We see no way to skirt the question Exelon tees up: Under ISO-NE's new Tariff rules, does a supplier's rate enter the auction so long as it convinces the commission that the rate is just and reasonable, over contrary claims of the Market Monitor?" the court said.

Ambiguous Language

FERC found that "certain aspects of the relevant Tariff language and the commission's prior orders interpreting that language are ambiguous." It ruled that the RTO's filing must include "the relevant information and justification submitted by both the capacity supplier and the Internal Market Monitor."

The commission last March approved ISO-NE's request to reduce the dynamic delist threshold for FCA 13 to $4.30/kW-month from the $5.50/kW-month used in FCAs 10 to 12 (*ER18-620*). The threshold, which must be revised every three years, is a key parameter for generators considering retirement, which must submit delist bids to opt out of the capacity auction. (See *FERC OKs Lower Delist Threshold in ISO-NE*.)

"To the extent that the commission's prior orders in this proceeding can be interpreted as inconsistent with our answers to the court's remand, we reject those interpretations," FERC said in the Jan. 29 order, which revised paragraphs 18, 19 and 25 of the Oct. 30 order.

"As the court correctly noted, in the case of a conditional retirement, a mitigated bid is entered into the auction, but the resource will only retire at its originally submitted price," the commission said. "If the clearing price is below both the original bid and mitigated bid, the unit retires. If the clearing price is at or above both bids, the supplier takes on a capacity obligation. If the clearing price is at or above the mitigated bid but below the original bid, the unit must retire."

Accepts CASPR Tariff Revisions

In a separate order Jan. 29, the commission accepted the RTO's Tariff revisions to support implementation of the Competitive Auctions with Sponsored Policy Resources (CASPR) rules that the commission accepted in March 2018 (*ER19-444*). (See *Split FERC Approves ISO-NE CASPR Plan*.)

"With respect to the test price mechanism, we find that it is a just and reasonable means to address the potential incentive for bid-shading created by the CASPR modifications to the Forward Capacity Market," the commission said. "Bid-shading" refers to the practice of resources electing to offer their capacity below the RTO's assessment of their going-forward costs.

ISO-NE filed the Tariff revisions Nov. 30 after FERC on July 2 *denied* a Tariff waiver to allow the RTO to enter a cost-of-service agreement to keep Exelon's 2,274-MW Mystic plant running after its capacity supply obligations (CSOs) expire in May 2022. The commission instead directed the RTO to revise its rules to allow such agreements in order to address fuel security. (See *FERC Denies ISO-NE Mystic Waiver, Orders Tariff Changes*.)

'Confounding Interpretation'

In a partial dissent, Commissioner Richard Glick said the RTO seemed to be working at cross-purposes to the stated mission of CASPR's substitution auction to provide state-sponsored resources subject to a minimum offer price rule (MOPR) a chance to purchase a CSO — and the associated revenue stream — from a resource that then retires from the market.

"ISO-NE adopted what can only be described as a confounding interpretation of what qualifies as a state-sponsored resource," Glick said, referring to a provision requiring the resource be located within a state's geographical boundaries.

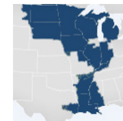
"Specifically, the [RTO] concluded that an offshore wind facility that is procured pursuant to a state-mandated solicitation and that is electrically located in that state does not qualify as a state-sponsored resource for the purpose of the renewable technology resource exemption (RTR) to the MOPR, which CASPR retained as a transition mechanism to the fully fledged substitution auction," he said.

Glick characterized the RTO's interpretation as "discouraging" and as putting up "an unnecessary barrier to the type of resources that CASPR was supposed to accommodate."

The RTO also proposed to bar from the substitution auction resources that bid-shade even if those resources clear the capacity construct and receive a CSO. Glick said the "unambiguous result" of that change "will be to again tilt the scales in favor of retaining traditional resources and against the incorporation of state-sponsored resources. As a result of this proposal, a resource that might otherwise retire through the substitution auction will instead remain in the market, holding a CSO that it could have sold to a state-sponsored resource." ■

Brayton Point Power Plant

MISO News



MISO Maintains Reliability Through Arctic Midwest Temps

Utilities Issue Conservation Appeals

By Amanda Durish Cook

CARMEL, Ind. — Record-breaking cold Wednesday and Thursday brought MISO's eighth-ever maximum generation event and multiple appeals for conservation from utilities in the northern portions of the RTO's footprint.

But data on the emergency event are in short supply for now. Speaking at a Reliability Subcommittee meeting on Thursday, Director of Regional Operations Michael McMullen said it was too early for MISO to have prepared data to share. He told stakeholders the RTO will have more information at upcoming public meetings.

At the time of the RSC meeting, MISO's maximum generation alert had expired and the RTO was operating under a maximum generation *warning* through the morning. (See *Cold Snap Halts DER Talk as MISO Calls Max Gen Event*.)

But McMullen did reveal that the grid operator was able to maintain reliability during the dangerous cold on Jan. 30.

"In that sense, it was a good operating day," he added.

Chris Miller, of FERC's Office of Energy Market Regulation, thanked MISO for working to maintain reliability through the historic cold.

Temperatures across MISO Midwest were about 15 to 30 degrees Fahrenheit below average.

An IPL lineman obscured by winter gear | *Indianapolis Power and Light*

Gas Shortage Warnings

The cold snap brought multiple gas shortage advisories in the northern portion of the MISO footprint.

During the event, both Consumers Energy and DTE Energy *issued* public appeals for conservation on Jan. 30. Consumers said ratepayers should lower thermostats or risk a gas shortage. The company also asked General Motors to suspend operations at about a dozen manufacturing sites. Consumers' gas scarcity was compounded by a recent fire at one of its natural gas compressor stations near Detroit.

"We greatly appreciate conservation efforts by all natural gas customers across Lower Michigan to assist with a supply issue on our gas distribution network. Conservation, even by gas customers served by other utilities than Consumers Energy, is making a difference. This morning, we are cautiously optimistic that our public requests to reduce gas use are having a positive effect," Consumers *posted* on Facebook on Friday morning.

In a video shared on social media, Michigan Gov. Gretchen Whitmer asked all residents in the Lower Peninsula to set their thermostats to 65 degrees Fahrenheit until noon on Friday. Several businesses were also complying with the request.

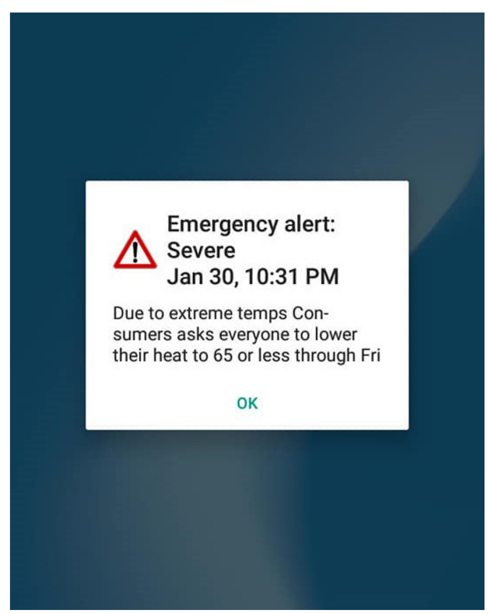
In Minnesota, Xcel Energy asked its gas customers to lower thermostats to 63 degrees through Thursday in order to sustain operations. "During this extremely cold weather, we are asking our Minnesota customers to help conserve natural gas so the system can continue to operate well for our customers throughout the state," Xcel *said* Wednesday.

However, Xcel later on Thursday had to interrupt gas service to about 150 customers in central Minnesota because of a constrained portion of the system that temporarily lost pressure. The company *reportedly* booked rooms at several nearby hotels for affected customers.

Transmission owner ITC Holdings said it had suspended all routine maintenance and put some equipment back into service. ITC Chief Operating Officer Jon Jipping said the company sent crews out a few days in advance to check equipment and said crews were "actively monitoring equipment" as the cold settled in on Jan. 30. He also said ITC remained in contact with the Michigan Public Service Commission throughout the statewide emergency. At the time, ITC — which usually imports electricity into Michigan — reported exporting about 1,500 MW, most flowing south to other MISO zones and PJM.

Consumers Energy lineman | *Consumers Energy*

"The more extreme events that we have, the more normal they become for us," ITC Michigan President Simon Whitelocke said in a phone interview with *RTO Insider*. "Part of our job is to plan for a system that can handle this extreme weather we're seeing." ■



An emergency smartphone alert from Consumers Energy | *Facebook*

MISO News

Cold Snap Halts DER Talk as MISO Calls Max Gen Event

By Amanda Durish Cook

CARMEL, Ind. — A dangerous cold snap spurred a maximum generation event and knocked out power to MISO's offices Wednesday.

The arrival of the polar vortex cut short a two-day RTO workshop focusing on distributed energy resource participation, canceling an in-depth *discussion* on the technical concerns of adding significant amount of DERs to the grid.

As MISO security checked identification with flashlights in a darkened lobby about 8 a.m. and sent staff to work from home, temperatures hit -10 degrees Fahrenheit with a -40 windchill. At the same time, Minneapolis registered -30 F and a wind chill below -50.

By then, the MISO Reliability Coordinator had *declared* conservative operations, suspending all transmission and generation maintenance, and a maximum generation *event* for its North and Central regions because of forced outages and higher-than-expected load. Both *declarations* will lasted through Thursday. The power outage did not extend to the control room. MISO first issued a cold weather alert on Jan. 25 covering Jan. 29 to Feb. 1. (See *MISO Issues Cold Weather Alert*.)

The first day of the workshop on Jan. 29 focused only on an introduction to DERs, with speaker Bob Shively of Enerdynamics outlining the several unknowns surrounding DER adoption. The second day was to focus on topics such as DER interconnection, forecasting and reliability issues.

After relative quiet in public stakeholder groups on DER penetration for several months, MISO leadership last year said it will begin work on a possible participation model in anticipation of a FERC rule on the issue. (See *MISO Offers Storage Proposal, Promises to Exceed Order 841*.) Before the inclement weather, the RTO had already planned two more two-day DER workshops in *March* in cooperation with the Organization of MISO States.

Staff said that although NERC has a definition of DERs, MISO has yet to establish its own independent definition.

The Unknown

Shively said there's a great deal of uncertainty about how quickly DERs will permeate the energy landscape.

"It could happen in some states very quickly. It could happen in other states not so quickly. … We don't know what's going to be the adoption curve of consumers. … You can get people saying this, and people saying that. The answer is nobody really knows. You need to do your planning in mind thinking that nobody really knows," Shively said.

He then *cited* Bill Gates' book "The Road Ahead": "We always overestimate the change that will occur in the next two years and underestimate the change that will occur in the next 10. Don't let yourself be lulled into inaction."

But Shively said planners will have to anticipate what they literally cannot see today.

The bulk electric system and markets are not designed to incorporate DERs, he said, which lack visibility on the grid, leaving planners to exclude them in their models when they do not receive operational data.

"Bulk power system planners do not have access to data on distributed energy resources. … All that data rests with distribution companies and there's really no coordination," Shively said.

Several factors will affect the rate of DER adoption, he said, including the pace of state regulation and a possible FERC ruling. In some cases, he's already witnessed the need to equip substations at the distribution level to allow generation from DERs to flow back to the grid. However, he noted, early compensation, new reliability rules and net metering changes can make or break widespread adoption. Different states might experience wildly different penetration rates. He also said utility distribution companies may have to create special DER monitoring systems.

Shively said distribution companies will soon need to reinvent themselves as DER communications networks.

"I had a guy from Duke tell me, 'We're no longer an energy company. We're a high-tech communications data energy grid,'" Shively said.

He also pointed to New York's Reforming the Energy Vision, a set of multiyear regulatory decisions and policy initiatives launched in 2014 with the goal of creating a distributed system platform provider, among other objectives.

"It's probably harder to plan DER integration on distribution versus transmission. For distribution, you're changing the whole way you model each of your distribution circuits," Shively said.

'Sneaky' Devices

Shively said all internet-enabled devices today have the potential to become a DER.

"Anyone who has Alexa or Google to control the lights, you have a potential distributed energy resource in your home," he said.

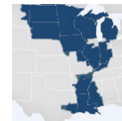
Shively cited a recent *Wall Street Journal* *article* on Google and Amazon planning for industry traction in third-party home automation and home area networks.

"More and more, things you're buying today are sneakily internet-enabled whether you want them to be or not," Shively said. He said soon, customers may be able to dictate rules such as adjusting the thermostat by 2 degrees when kilowatt-hours reach a certain price.

MISO's next DER workshop will be held March 21-22 in Metairie, La. ■

An empty Indianapolis street on Jan. 30 | © *RTO Insider*

MISO News



MISO Files New Planned Outage Rules

By Amanda Durish Cook

CARMEL, Ind. — MISO filed new requirements on outage coordination last week despite the fact that some stakeholders still aren't entirely sold on the plan.

The Wednesday filing seeks to impose new generator accreditation penalties for planned outages taken during what MISO deems "low-margin, high-risk periods" (*ER19-915*).

Speaking at a Reliability Subcommittee meeting Thursday, Jeanna Furnish of MISO's outage coordination team said the plan will incent the forward scheduling of planned generation outages. She said the RTO is now revising its Business Practices Manual language to match the Tariff filing should FERC accept the proposal.

"Increasing forced outage rates for generation in the MISO region, together with a significant correlation in the timing of planned generator outages and derates, have caused resource risk outside of the traditional summer peak times. This has created a new paradigm, where generator owners can no longer simply schedule their outages around peak load times to avoid operating risk," MISO explained in its filing.

The RTO's proposal would require generation resources to provide 120 days' notice for planned outages, although those scheduled 14 to 119 days in advance would be exempt from accreditation penalties provided they are scheduled during predefined periods with adequate margins. Penalties would apply to planned outages and derates scheduled fewer than 14 days in advance and occurring during a declared maximum generation emergency. The proposal also provides safe harbor provisions for resources if a planned outage is adjusted at MISO's request.

MISO has also proposed a transition period for the new rules, which would exempt outages scheduled prior to April 1 from the accreditation penalty. Requests and revisions submitted April 1 or later for outages starting April 15 through July 29 would be exempt from the penalty if the request is submitted no later than 14 days in advance and MISO foresees "adequate projected margin at the time of the request." The full set of outage requirements will go into effect for outages scheduled to start July 30 or later.

While the rules are considerably less strict than the ones MISO had originally proposed, some stakeholders were still calling for more lenient requirements up until the time of filing. (See *MISO Moves to Examine Long-term Supply Measures* and *Stakeholders Press MISO for Flexibility in Outage Proposal*.) Other stakeholders were repeating calls for the RTO to improve its own load forecasting.

In comments to MISO, Ameren Missouri said the two weeks' notice requirement should be reduced to just one week, "more commensurate with the load and weather forecasting accuracy." DTE Energy also called for a seven-day notice requirement in addition to a request that MISO provide daily updates to its Maintenance Margin, a nonpublic member webpage that keeps a monthly forward account of how many megawatts can be taken out of service without affecting reliability.

Jeanna Furnish | © *RTO Insider*

At least one stakeholder still had bigger problems with the outage coordination proposal.

"Reforms have been focused solely on penalizing generation owners," Exelon's David Bloom wrote. "Instead, MISO and its stakeholders should continue to examine ways to improve MISO load forecasting or consider new or modified requirements to use existing tools like the Maintenance Margin."

Exelon also criticized MISO's requirement to count a full 24 hours of a planned outage as forced when it is scheduled without the two-week notice and during a generation emergency, even when emergency conditions persist for shorter periods. The proposal is still "unduly punitive," Exelon said. MISO's proposal assesses a forced outage penalty against resource accreditation for a minimum of 24 hours or the overlap between an outage scheduled without the two-week notice and emergency conditions, whichever is greater. ■

MISO NEWS

MISO, SPP Pushing for Annual Joint Studies

By Tom Kleckner

MISO's Ben Stearney (left) and SPP's Adam Bell prepare for the Mardi Gras-themed IPSAC meeting. | © *RTO Insider*

METAIRIE, La. — MISO and SPP staff told stakeholders last week that there is "more support than not" for the RTOs to conduct a joint study of interregional transmission projects in 2019, and each year after that.

The RTOs' interregional groups spent much of 2018 revising their joint operating agreement to increase the odds of agreeing on interregional projects. By improving the joint study — or coordinated system plan (CSP) — and its efficiency and effectiveness, the RTOs hope to identify and build "cost-effective projects that provide benefits to both regions." (See *MISO, SPP Tweak Interregional Criteria*.)

The staffs eliminated a $5 million cost threshold for the projects, added avoided costs and adjusted production cost benefits to project evaluation, mandated CSP studies, and removed the joint modeling requirement in favor of individual RTO regional analyses done simultaneously.

MISO Expansion Planning Engineer Ben Stearney said during a Jan. 31 Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting that staff expect the joint study to be done annually. The committee later this month will help determine whether that process begins this year.

"This will allow us to prepare a better analysis or comparison of regional projects, because they're done simultaneously," Stearney said.

MISO and SPP conducted CSP and regional reviews in 2014 and 2016 but were unable to reach an agreement on the few projects they targeted.

"The change allows us to get to the solution quicker," said SPP's Casey Cathey, manager of reliability planning and seams.

SPP Interregional Coordinator Adam Bell conducted an in-depth review of the *joint study process* and its continued focus on coordination between the RTOs. "The better you understand each other's processes, the better we'll be," he told stakeholders.

Bell said economic models, using four futures on MISO's side and two on SPP's, will be used to identify regional needs. The models will be developed out of the existing MISO Transmission Expansion Plan and SPP's Integrated Transmission Planning, respectively.

"MISO will be able to evaluate projects as they would do regionally, as will SPP," Bell said. "While it's not exactly an apples-to-apples comparison, it doesn't preclude you from finding projects that are beneficial to both.

"All that's really required of a regional need," he said, "is that it comes out of the MTEP or ITP."

SPP's needs solution window closes Feb. 6, while MISO's ends March 1.

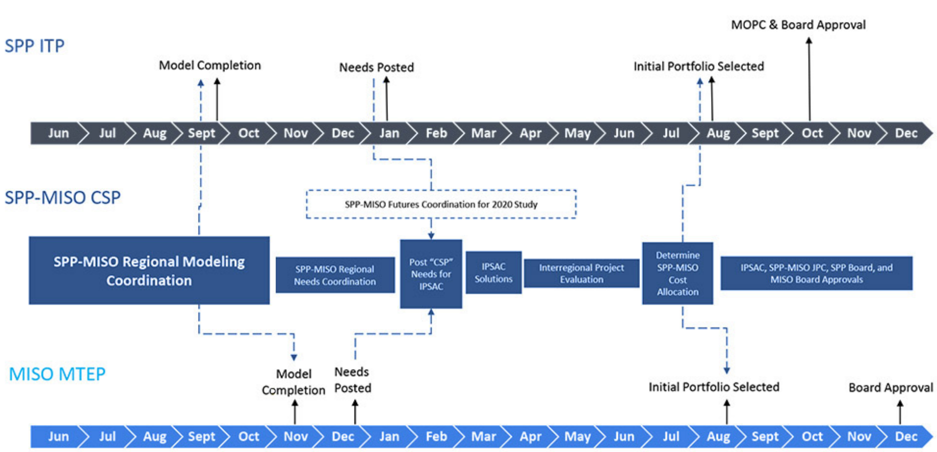
The RTOs have also added both a study model review and project review by the Joint Planning Committee, an interregional group comprising representatives from both RTOs. The JPC will also vote on a project's proposed interregional cost allocation.

Under the proposed CSP interregional cost allocation, SPP and MISO will each calculate project benefits using their respective regional models. The share of project costs will be based on the percentage of the total project benefit.

The respective legal departments are reviewing the revised JOA language. The RTOs expect a FERC filing to be made in March.

The IPSAC will hold a conference call Feb. 26 to continue the needs discussion and determine whether to conduct a joint study this year.

Last week's meeting was almost held at MISO's facility in Eden, Minn., where the temperature was -8 degrees Fahrenheit. The temperature in Metairie was 62 F at the same time. ■



CSP process overview | *MISO & SPP*

NYISO News

NYISO Management Committee Briefs

RENSSELAER, N.Y. — NYISO last month incorporated additional 115-kV transmission facilities in its energy market model, Chief Operating Officer Rick Gonzales told the Management Committee on Wednesday.

Gonzales said the facilities, mostly in western New York, were incorporated into the real-time market on Dec. 4 and the day-ahead market on Dec. 5. "Commensurate with that activity, we also deployed an enhanced Niagara model, which allows us to better address those transmission constraints," Gonzales said in delivering the monthly operations *report*.

The Niagara Power Plant comprises 25 individual generating units, divided into three bulk power system injection points: Niagara 230-kV Bus (1,770 MW total); Niagara 115-kV East Bus (860 MW total); and Niagara 115-kV West Bus (645 MW total).

The ISO previously represented all 25 units as a single facility in the market models, which precluded the market model from shifting generation among these units to manage congestion and increase output from the plant. Operators can now shift output among these generators to manage congestion on both the 230-kV and 115-kV facilities.

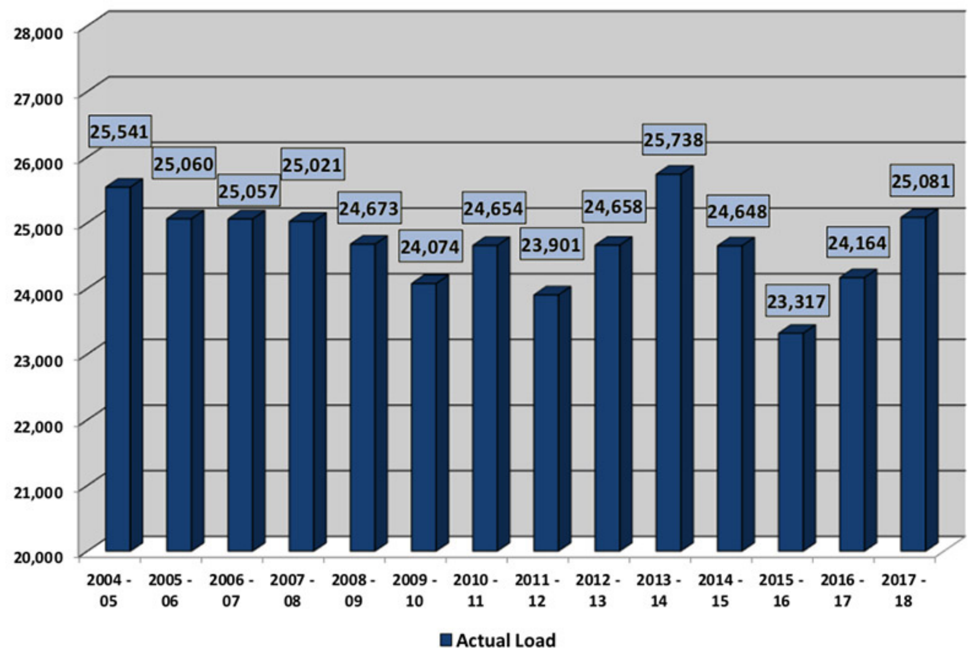
Last month's moves completed a project to begin scheduling and pricing more than 20 lower-voltage transmission facilities in the day-ahead and real-time markets, an effort the ISO's Market Monitoring Unit, Potomac Economics, had recommended since 2014. (See "ISO to Begin Incorporating 100+kV Tx Facilities in Markets," *NYISO Business Issues Committee Briefs: Sept. 12, 2018*.)

Howard Fromer, director of market policy for PSEG Power New York, asked whether the changes had led to a reduction in out-of-merit actions or prices.

"We're very happy with the way that those two actions have turned out," Gonzales said. "Securing the 115 kV with its additional constraints into our energy market has resulted in significant reductions in out-of-merit actions for Niagara or Ontario imports."

He said the enhanced Niagara modeling should result in much more price stability in the entire New York Control Area because Niagara is a significant supplier of energy, reserves and regulation.

The ISO's Manual 12, Transmission and Dispatch Operations Manual, says, "From time to time, generators must be operated out of economic order or at levels that are inconsistent with the calculated schedules. Any NYISO-authorized deviation from the schedule is considered out-of-merit (OOM) generation and is not subject to regulation penalties. A unit that is out-of-merit is balanced at actual output and may be eligible for a supplemental payment if its bid production cost is not met."



NYISO winter peak loads (MW): 2004/05 to 2017/18 | *NYISO*

Winter: So Far, So Good

Emilie Nelson, NYISO vice president of market operations, gave an update on January operations, noting the cold weather over the Martin Luther King Jr. Day weekend (Jan. 19-22) and the arctic blast that hit the state that day.

Although there was substantial snowfall upstate, the storm caused no real transmission or distribution issues, Nelson said. Good coordination with transmission owners and neighboring grid operators led to some transmission being returned to service from maintenance outages in advance of the anticipated weather, she said.

"We did see in advance of the [MLK] weekend generators begin to switch to oil, with escalated gas prices and some limitations projected in advance of Monday, which was the coldest day," Nelson said. "We of course have a weekly fuel survey process — which can occur more frequently for prolonged periods of cold weather — and we had sufficient oil inventories."

Demand peaked at 24,728 MW on Monday, Jan. 21, exceeding the 90/10 day-ahead forecast, she said. The demand for energy reflected peak temperatures across the New York Control Area of 8.8 degrees Fahrenheit, which came in very close to the forecast. The minimums experienced were 3 F in Syracuse, 0 F in Albany and 6 F in New York City.

"This was the first time [this winter] we had the cold extend all the way into the downstate regions," she said. On Jan. 21, the ISO saw about 700 MW of derates because of fuel-related issues and an additional 160 MW from other cold weather issues, Nelson said.

Consolidated Edison, National Grid and other natural gas pipeline operators issued operational flow orders in advance.

The storm hitting as she spoke looked to be very similar to the one in mid-January, both in terms of projected peak load and the value of low temperatures across the state, Nelson said.

Committee Approves Repricing TCC Credit Requirement

The MC approved using the market clearing

Continued on page 25

NYISO News

NYISO Looks at Carbon Charge Credit Effects, Tariff Revisions

By Michael Kuser

RENSSELAER, N.Y. — NYISO stakeholders learned Thursday that pricing carbon into the wholesale energy market would have little effect on corporate credit rules and that any necessary changes will only be discussed after a second-quarter vote on market design and Tariff revisions.

ISO Manager of Corporate Credit Sheri Prevratil *told* the Market Issues Working Group that, based on the current market design, the only potential change might be to adjust the projected true-up exposure timing of transaction settlements to reflect the true-up timing of emission charges.

"Currently, that particular [timing] requirement is triggered off only four-month true-up as a percentage of the initial invoice," Prevratil said. "Depending on the timing of when those carbon true-ups come in, it may impact [that] and we might have to make a change on the trigger to the final bill closeout as it relates to the initial or formal settlement.

"But that's the only one that right now I see might have to change as a credit rule," Prevratil said.

If necessary, such rule changes would likely have to go through the ISO's Billing, Credit and Accounting Working Group, and potential credit rule changes would not delay implementation plans for carbon pricing, she said.

New York's Implementing Public Policy Task Force in December turned its carbon pricing proposal over to the ISO's stakeholder process through the MIWG, which began its work in January. (See *Imports/Exports Top Talk at NYISO Carbon Pricing Kick-off*.)

Energy Credit Components

NYISO will also evaluate potential adjustments in the external transactions component to account for carbon charges on imports and carbon payments on exports.

"Currently, we do anticipate that that carbon charge or carbon payment will just be a part of the daily net gains and losses, part of those calculations, and just summed up daily as the daily bill finalizes," Prevratil said. "Carbon pricing will net in the daily advisory bill and will therefore net against daily energy purchases or sales in the Energy and Ancillary Services credit calculation."

At the previous MIWG meeting, market participants expressed concern about a gross carbon charge that would be netted against the residuals in net cost, and that the resulting net amount would be further netted with all the other energy and ancillary services numbers that go into that calculation, she said.

The intent of the second part of the calculation is to capture changes, Prevratil said. "For example, we're in a polar vortex right now. ... If that run rate on average exceeds what we're already holding, then you're going to get a collateral call and it will be due two business days later. That will continue, but that's a rolling 10-day run rate, so once those charges go down, then it will fall back to the first part of the calculation.

"We don't anticipate changing the methodology of this," Prevratil said.

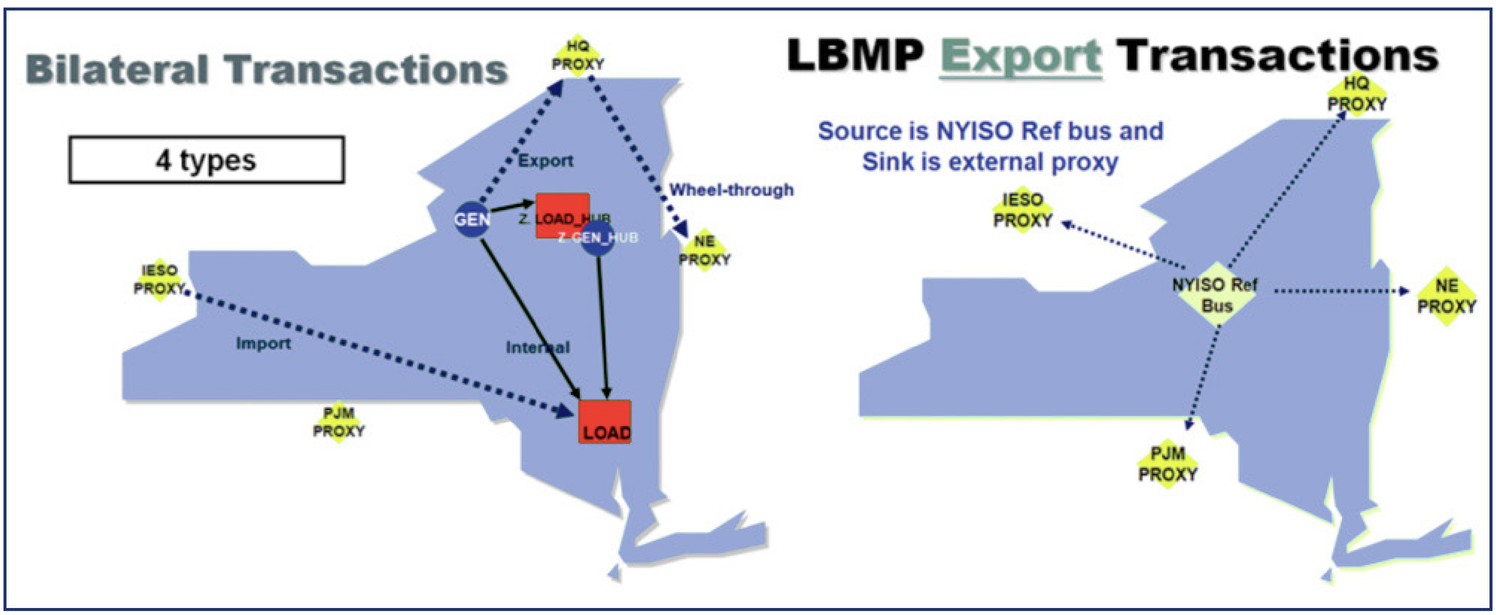
The energy and ancillary services credit requirement equals the higher of the following:

- The highest month's price adjusted energy purchases in the prior equivalent capability period divided by the number of days in that month, multiplied by 16 days; or
- The total average daily energy purchases incurred over the last 10 days, multiplied by 16 days.

New Tariff Sections

Pricing carbon into the wholesale energy market would require new Tariff sections related to applying a carbon charge, defining the social cost of carbon (SCC) and allocating carbon residuals, Ethan D. Avallone, senior energy market design specialist, told the MIWG.

NYISO's Market Administration and Control Area Services Tariff (MST) would also require



There may be more than one proxy generator bus at a particular interface with a neighboring control area to enable NYISO to distinguish the bidding, treatment and pricing of products and services at the interface. | *NYISO*

NYISO News

revisions to other sections, and subsequent Tariff presentations, including redline Tariff sheets, will build on the *one* considered at Thursday's meeting, Avallone said. (See *NYISO Looks at Carbon Charge Tariff Impacts, Residuals*.)

As an example, Avallone pointed out, MST sections 7.2 and 7.4 would need to address emissions data reporting; section 17 would address the carbon component of the locational-based marginal price (LBMPc); section 23.3 would cover emission rates and reference levels under a carbon charge; and section 26 would cover any potential credit rule changes. NYISO will address those details when credit discussions begin this fall after approval of the carbon pricing market design.

Stakeholders asked what would happen to the ISO's carbon pricing scheme if New York were to implement a carbon tax.

"We will follow what's in the budget bill, and we will evaluate how it impacts NYISO's efforts," said James Sweeney, a senior attorney at the ISO. "We will make efforts in the Tariff such that entities don't pay twice for carbon. How exactly it would be done is yet to be determined."

The ISO foresees no revisions to MST sections 4.2 and 4.5, which describe day-ahead and real-time energy settlements, respectively, nor to guarantee payments such as bid production cost guarantees (BPCG), day-ahead margin assurance payments (DAMAP) and import curtailment guarantee payments.

NYISO's current guarantee payment practices will continue under carbon pricing, Avallone said.

He emphasized that the ISO will charge each supplier on carbon emissions resulting from actual energy flows.

For example, NYISO will charge each supplier scheduling imports or pay each supplier scheduling exports the LBMPc at the relevant proxy generator bus, but the supplier will not be subject to a carbon charge or payment if the transaction fails in the ISO's checkout process or is curtailed at the ISO's request.

The latest NYISO *schedule* on carbon pricing calls for discussing LBMPc calculation and identifying marginal units on Feb. 15; Tariff revisions on Feb. 28 and March 18; and carbon bid adjustment for opportunity cost resources on March 4. ■

NYISO Management Committee Briefs

Continued from page 23

price to calculate the credit requirement for fixed-price transmission congestion contracts (TCCs), in accordance with Market Services Tariff Section 26.4.2.4.1.

Sheri Prevratil, NYISO manager of corporate credit, *reiterated* the case she made in persuading the Business Issues Committee earlier in January, which recommended the measure to the MC. (See *NYISO Business Issues Committee Briefs: Jan. 16, 2019*.)

Under the changes, the ISO will use $0 as the payment obligation portion of the requirement if the price calculated for the fixed-price TCC is less than $0. Otherwise it will continue to use the greater of the payment obligation or the credit holding requirement until receiving payment for the contract. The credit holding requirement is the greater of the auction TCC holding requirement, the fixed-price TCC holding requirement or the mark-to-market calculation.

"Essentially we're just proposing to change the fixed-price TCC credit requirement to be in line with the holding requirement for auction TCCs," Prevratil said.

Asked whether stakeholders were adequately protected from the risk of a default like that of GreenHat Energy in PJM, Prevratil said, "Yes, in the end we will be covered more appropriately for these TCCs because the market clearing price will be used to better reflect the risk of the TCC instead of using the fixed price across the term of the TCC." (See *FERC OKs Key PJM Changes to Address GreenHat Default*.)

| New York Power Authority

If the change is approved by the Board of Directors in March, the ISO will file with FERC in April for deployment in June. ■

— Michael Kuser

PJM News

Utility CEOs Urge PJM Board to Act on Price Formation

By Christen Smith

Four top utility executives urged PJM's Board of Managers to act on price formation at its Feb. 12 meeting after stakeholders deadlocked on the issue last week.

CEOs Chris Crane of Exelon, Ralph Izzo of Public Service Enterprise Group and Charles E. Jones of FirstEnergy signed a Jan. 29 *letter* criticizing PJM for failing to implement energy and capacity market rule changes despite a decade of stakeholder discussions. Douglas Esamann, president of Duke Energy's Midwest and Florida regions, also signed the letter, which said PJM was lagging behind other eastern RTOs and ISOs in addressing its "woefully out of date" operating reserve demand curve.

"Specifically, PJM has not been able to adequately navigate the current stakeholder process that was initiated to address key energy market price formation issues," they said. "As a result, critical reforms have been mired in regulatory proceedings for years."

Crane and Izzo have long supported changes to PJM's market price formation methodology, calling it a "no brainer" and "long overdue." (See *CEOs See Dollar Signs in ZECs, PJM Price Formation*.) They and Jones have threatened to shutter their struggling nuclear plants without rule changes to increase the plants' revenues. FirstEnergy also has sought subsidies for its coal-fired generation.

"It is imperative that the board and PJM act swiftly and decisively on important price formation reforms so that these fundamental issues can be addressed within the PJM markets," the executives concluded. "The markets are at a critical juncture and clear leadership is necessary to ensure the markets evolve to work as efficiently as intended and meet the needs of customers and investors."

'Not Enough'

Aside from the RTO's stalled price formation initiative, the executives also chastised PJM for not defining resilience attributes and reacting too slowly to fuel security concerns following the December 2018 NERC report highlighting potential risks from accelerated retirements. (See *NERC Releases 'Stress Test' Analysis of Gen Retirements*.)

"Instead of driving changes for appropriate market price signals, PJM remains a facilitator to implement changes that achieve stakeholder consensus," they said. "This is simply not enough."

"This letter is one of a number of communications we expect to receive on the subject of reserve price formation and the stakeholder process in advance on the next PJM Board of Managers meeting," PJM spokeswoman Susan Buehler said. "The board will take all stakeholder comments into consideration before reaching any decisions."

Jeff Dennis, managing director and general counsel of Advanced Energy Economy, criticized the companies' reliance on the NERC report and PJM's own fuel security *study* as the basis for pushing through regulatory changes without stakeholder consensus.

"Let's be clear — they're trying to shortcut the stakeholder process on those issues based on two reports that make no showing of likely reliability risks in the near or immediate term, finding long-term risks in only the most extreme scenarios," he *tweeted* Thursday. "If we're going to continue the search for the black swan, let's at least do it in an open, technology-neutral way that actually addresses demonstrated grid needs, rather than forcing discriminatory tech-specific market rules that benefit fuel-dependent resources."

Stakeholder Deadlock

The executives' letter came less than a week after the Markets and Reliability Committee failed to approve any of five price formation proposals — from PJM, Calpine, the Independent Market Monitor, the D.C. Office of the People's Counsel and Vistra Energy.

At the Jan. 24 meeting, load interests balked at the Jan. 31 deadline set by the board for stakeholder action. Exelon's Jason Barker expressed frustration over the load interests' request for more time after more than a year of discussions, saying "the time is now to move forward." (See *PJM Stakeholders Deadlock on Energy Price Formation*.)

More than 60% of transmission owners *voted* in favor PJM's plan or Calpine's compromise package. The Vistra plan likewise received 86% support from TOs. Electric distributors and end-use customers unanimously supported the Monitor proposal instead. None came close to the two-thirds sector-weighted vote needed for approval.

PJM CEO Andy Ott said last week the board will consider input from both the MRC and upcoming Liaison Committee meetings before submitting a FERC filing on the issue. The Members Committee agreed to hold a special conference call no later than Feb. 8 if additional discussions yield a potential compromise in the interim. ■

Exelon CEO Chris Crane | © *RTO Insider*

PSEG CEO Ralph Izzo | © *RTO Insider*

FirstEnergy CEO Charles E. Jones | *FirstEnergy*

PJM News

FERC Orders PJM to Unwind GreenHat Settlements

Rejects Request to Hold Related Firm's Collateral [Originally published 1/31/19]

By Rich Heidorn Jr.

PJM must unwind five months of settlements for GreenHat Energy financial transmission rights that should have been liquidated sooner, FERC ruled Wednesday (*ER18-2068*).

In addition to rejecting PJM's request for a waiver of its liquidation rules, the commission also rebuffed the RTO's request to retain $550,000 in collateral posted by one of GreenHat's principals through a second company (*ER18-1972*).

The two rulings complicate the RTO's efforts to minimize the damage of GreenHat's default, which left other PJM members liable for more than $100 million.

The commission also disclosed that its Office of Enforcement is conducting a nonpublic investigation into whether GreenHat engaged in market manipulation or violated other commission rules. "That investigation is ongoing. The commission will determine what further action, if any, may be appropriate after it considers the results of the staff investigation," FERC said.

The RTO said it will ask the commission to reconsider its ruling on the liquidation waivers.

"PJM took the appropriate and immediate steps in the public interest, based on the legal vehicles and FERC precedents in effect, to stop a liquidation in an auction that was dysfunctional," RTO spokesman Jeff Shields responded late Wednesday. "PJM is disappointed that FERC, in its order, may not have fully appreciated the magnitude of the impact to our members and to consumers. PJM intends to file a rehearing and/or clarification request, and a motion to stay the order. We will have a notification for members in the coming days."

On Nov. 29, the commission had approved Tariff and Operating Agreement revisions that require defaulted FTR portfolios to go to settlement rather than being liquidated through auction (ER19-19). (See ***FERC OKs Key PJM Changes to Address GreenHat Default***.)

But the commission on Wednesday declined to make those rule changes retroactive, saying the waivers could harm other FTR market participants who had relied on the RTO's existing rules.

As described by FERC, PJM "paused aspects of" the July FTR auction after all bids and offers had been received, saying it was alarmed by a lack of liquidity and the size of risk premiums related to the GreenHat FTRs.

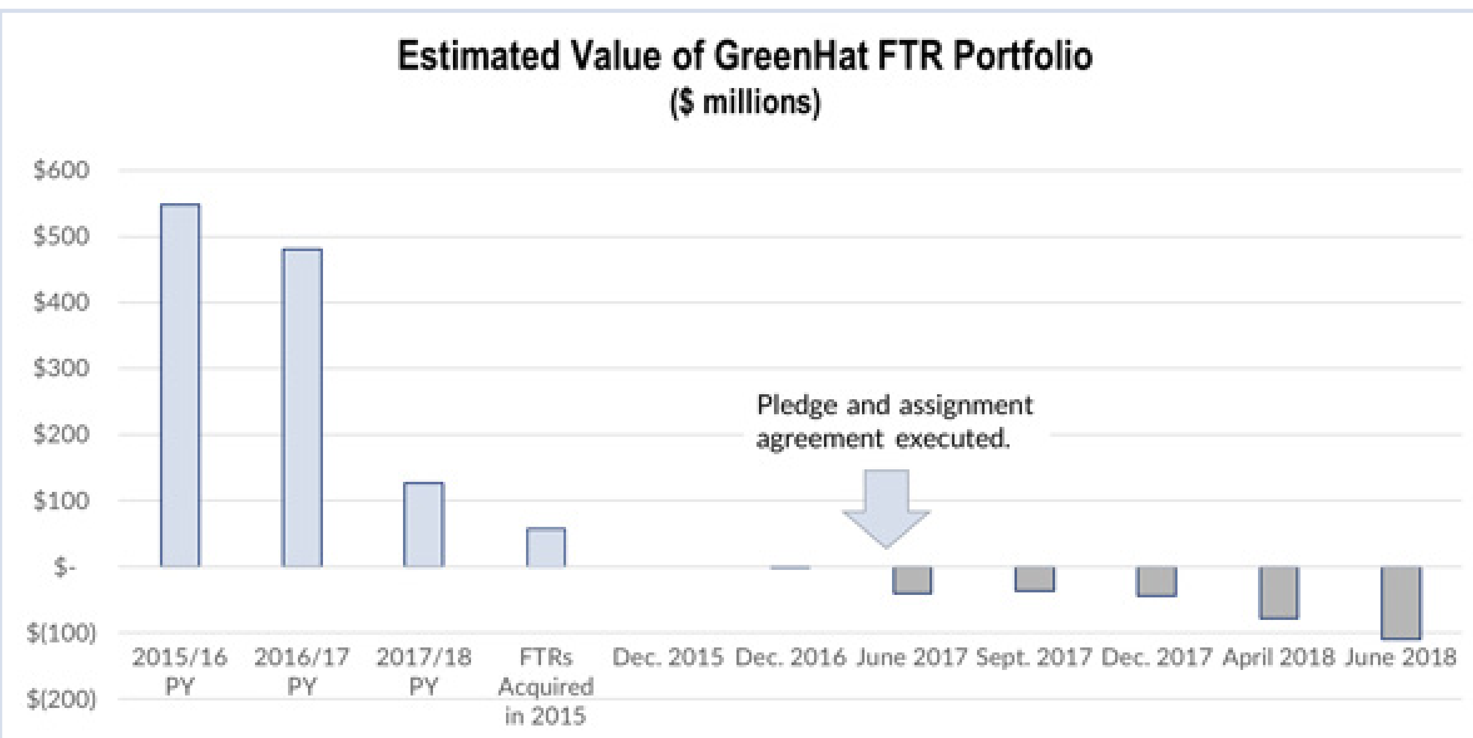
PJM said it would instead sell off the positions during the long-term FTR auction in September and the monthly auctions between July and October, offering only those positions effective in the prompt month (i.e., selling August FTR positions at the July auction, September FTR positions in the August auction, etc.)

The RTO asked FERC on July 26 for a waiver of Tariff rules requiring it to offer all of GreenHat's FTR positions at a price designed "to maximize the likelihood of liquidation," saying a slower liquidation of the company's large portfolio would reduce losses to members.

FERC ruled that PJM's request was not limited in scope.

"Changing the rules governing an already-commenced auction is a significant step that

Continued on page 28



PJM analysis shows the continuing downward trajectory of GreenHat's FTR portfolio. | *PJM*

PJM News

PJM: FERC Order Could Boost Default by $300M

Total GreenHat Loss May Exceed $430M

Continued from page 1

PJM would be required to resettle every FTR portfolio impacted by rerunning the prior auctions, it said. (See *FERC Orders PJM to Unwind GreenHat Settlements*.)

The resettlements would "likely place a number of members in breach of their collateral requirements of PJM's credit policy and require them to fulfill a collateral call within two business days based on the unanticipated changes in the positions in members' FTR portfolios that would result from changing the cleared results of the July 2018 FTR auction," Daugherty said.

The RTO asked FERC on July 26 for a waiver of Tariff rules requiring it to offer all of GreenHat's FTR positions at a price designed "to maximize the likelihood of liquidation." The RTO said a slower liquidation of the company's large portfolio would reduce losses to members.

But FERC said PJM's request would affect the outcome of the July FTR auction "as well as parties' confidence in the rules governing future proceedings."

The commission also rejected PJM's request to retain $550,000 in collateral posted by one of GreenHat's principals through a second company (*ER18-1972*).

PJM said it will ask FERC to rehear the waiver case and seek a stay on the order in the interim. Asked when the stay request would be filed, PJM spokesman Jeff Shields said, "We are still considering our legal options." ■

PJM Chief Financial Officer Suzanne Daugherty | © *RTO Insider*

FERC Orders PJM to Unwind GreenHat Settlements

Rejects Request to Hold Related Firm's Collateral

Continued from page 27

affects both the outcome of that particular auction as well as parties' confidence in the rules governing future proceedings. That is particularly so here, where the record indicates that PJM proposed the waiver in order to avoid the outcome that the already-commenced auction would have produced," FERC said.

"In addition, we note that PJM proposes to waive four discrete elements of the Tariff in order to potentially substitute new rules that were not yet formed, much less included in the record, at the time PJM made its waiver request. Such a significant change to multiple parameters of an already-commenced auction is not a remedy that is limited in scope. The record demonstrates that participants submitted bids in the July monthly FTR auction relying on the liquidation process that existed at the time PJM conducted the auction. Disrupting those settled expectations is likely to cause harm to third parties, even if doing so might produce [an] otherwise more efficient outcome, as PJM contends the waiver request would.

"To the extent PJM anticipated that the commission would grant the waiver request … PJM is required to reconcile any such actions by reinstating the original July auction results, or taking steps that are necessary to comply with the effective Tariff language when the July 2018 auction was conducted, and by unwinding settlements made for September, October, November, December and January positions that should have been liquidated."

'Unreasonably Harmed'

Separately, the commission also rejected PJM's request to withhold $550,000 in collateral posted by Orange Avenue, a second company owned by one of the GreenHat principals.

PJM asked to retain the collateral for up to one year while it decides whether to take legal action against GreenHat and apply Orange's collateral to GreenHat's debts.

Orange posted the collateral in February 2018, but before doing any trading, it sought on June 4 to withdraw from PJM and recover the collateral.

When PJM sought more collateral from GreenHat as its losses mounted in April 2017, the company gave the RTO the rights to collect money it said Shell Energy owed it for purchasing some of its FTR portfolio. PJM was left emptyhanded, however, when Shell said it had already paid GreenHat all it owed. (See *Shell Energy Seeks to Avoid Liability in GreenHat Trades*.)

PJM said it is reviewing whether to take legal action against GreenHat over its representations in negotiating the pledge agreement.

FERC denied PJM's request to hold Orange's money in the interim, saying the company "would be unreasonably harmed."

"While PJM states that it intends to investigate potential fraud with respect to the execution of the pledge agreement by the managing member of GreenHat, PJM fails to make any claim that Orange may have participated in any fraud, pointing out only that GreenHat and Orange have the same managing director. On the evidence submitted by PJM, therefore, we find that Orange would be unreasonably harmed by granting PJM a waiver request." ■

PJM News

PJM Weathers Arctic Blast

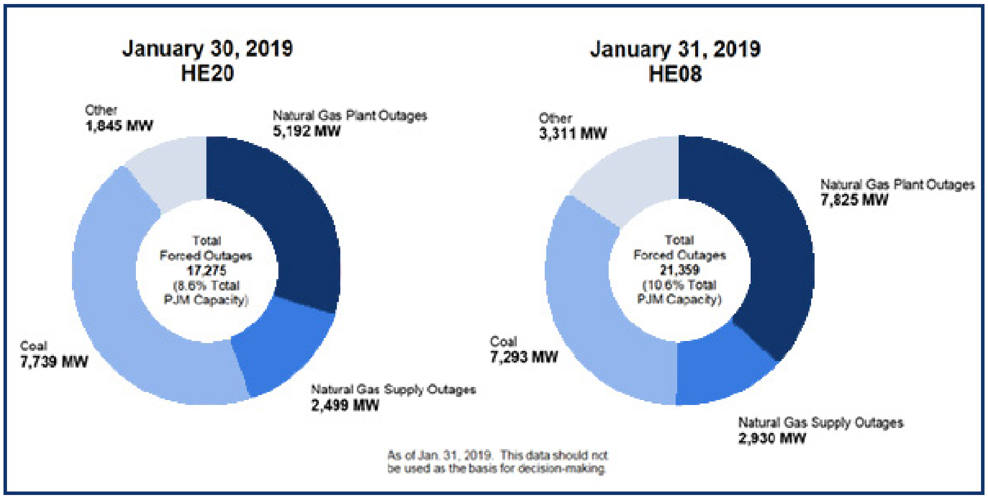
By Rich Heidorn Jr.

PJM survived last week's arctic blast with slightly elevated outages and two periods of shortage pricing, officials said.

The cold air hit the Commonwealth Edison zone near Chicago first, with actual temperatures dropping as low as -24 degrees Fahrenheit on Thursday morning.

PJM issued cold weather alerts for the ComEd zone last Tuesday, PJM West on Wednesday and the entire RTO on Thursday and Friday.

Forced generation outages peaked at 10.6% of total capacity Thursday (21,359 MW) after hitting 8.6% (17,275 MW) Wednesday. That was below the 12.1% (23,751 MW) on Jan. 7, 2018, the peak day last winter, and less than half the 22% (40,200 MW) of the 2014 polar vortex.



Forced generation outages peaked at 10.6% of total capacity in PJM on Thursday (21,359 MW) after hitting 8.6% (17,275 MW) Wednesday. | *PJM*

Natural gas and coal generators represented almost 85% of the outages, including 2,930 MW of gas generation that was idled because of a lack of fuel.

Unit 2 of Public Service Enterprise Group's Salem nuclear plant was forced to *shut down* at 3 a.m. Thursday after ice clogged the screens protecting its cooling water intake. Unit 1 also reduced power to 88% because one circulating water pump was shut down. Unit 2 was listed at 3% in the Nuclear Regulatory Commission status report Feb. 1.

PJM said the system energy price rose above $1,000/MWh early Thursday "following the loss of a generator in the eastern part of the RTO." Synchronized reserve prices exceeded $900/MWh in the Mid-Atlantic Dominion (MAD) sub-zone and $600/MWh for the RTO.

Load for the week peaked at 139,452 MW at 8 a.m. Thursday, with LMPs rising as high as $144/MWh and synchronized reserve prices hitting $102/MWh.

Shortage pricing occurred both early Thursday and during Wednesday's evening peak, following the forced outage of a generator in the western part of the RTO. Synchronized reserve prices hit $600/MWh in MAD and $300/MWh in the RTO, with energy prices peaking at $747/MWh for the RTO. ■

SPP

SPP Regional State Committee Briefs

Commission Staff not yet to Agreement on Cost Allocation Issues

NEW ORLEANS — Regulatory staffers have been unable to reach a consensus on possible revisions to cost allocation rules for wind-rich areas and may table their yearlong review, the Nebraska Power Review Board's John Krajewski told the SPP Regional State Committee last week.

The Cost Allocation Working Group, which reports to the RSC, is considering changes to SPP's highway/byway framework, which considers transmission facilities of 300 kV or more as highway infrastructure, with their costs allocated on a regionwide, postage-stamp basis. Facilities between 100 and 300 kV are categorized as byway facilities, with two-thirds of the cost assigned to the host zone and one-third allocated regionwide. Projects less than 100 kV are allocated entirely to the host zone.

Among its options, the CAWG is considering changing the 100- to 300-kV allocation percentage to 50% or 66% as it ponders different ways of charging for load.

The working group is also evaluating whether to consolidate transmission zones for the SPP Tariff's Schedule 11 charges, which cover transmission construction costs. Krajewski said zones encompassing diverse areas that include wind and non-wind zones would spread byway costs over a larger footprint.

Other options include modifying the 300-kV and less allocation percentage in wind-rich zones only and using a generation-injection rate applicable to all generation or just a subset.

"As we've worked through this, I've worked on the assumption there was a problem and it needed to be fixed," Krajewski said. "Some of my fellow CAWG members haven't reached that point yet.

"If there isn't a consensus [that] there's a problem [at the group's next meeting], we'll put away what we've worked on. If we reach a point where there is a problem, I would like to see ourselves narrow those options to two or three, where we can give some detailed analysis," he said. The CAWG's next meeting is a *conference call* set for Feb. 12.

Should it come to an agreement, the CAWG plans to turn its work into a white paper and make recommendations to the RSC and the Holistic Integrated Tariff Team, which is taking a broader look at cost allocation. (See "HITT Educates MOPC on its Progress, Learnings," *SPP Markets & Operations Policy Committee Briefs: Jan. 15, 2019*.)

"Those two processes need to be wedded up and worked together," Texas Public Utility Commission Chair DeAnn Walker said of the CAWG and HITT work. "I understand there's serious disagreement over whether there's a problem, but there's a lot of overlapping things here with the HITT that need to be worked on together."

SPP, MISO Regulators in Educational Phase

South Dakota's Kristie Fiegen jokes with Kansas' Shari Feist Albrecht (left), much to the amusement of Missouri's Scott Rupp and RSC Chair Kim O'Guinn (right) of Arkansas. | © *RTO Insider*

Kansas Corporation Commissioner Shari Feist Albrecht told the RSC that MISO and SPP regulators working on the RTOs' seam issues are still in the midst of their educational phase.

"We're suffering from some beginning-to-operate-jointly pains," said Albrecht, who represents SPP regulators on the *SPP-RSC/OMS Liaison Committee*.

The committee was created last year to work with SPP and MISO to improve market-based transactions and operations across the seam. (See *Regulators Examine MISO, SPP Seams Issues at NARUC*.)

RSC representatives and counterparts from the Organization of MISO States have produced a *white paper* and gathered *responses* from stakeholders on the paper. Not surprisingly, the RTOs' stakeholders cited interregional planning and cost allocation as the two primary issues.

Albrecht and Missouri Public Service Commissioner Daniel Hall moderated a panel discussion on seam issues during a recent Mid-America Regulatory Conference meeting. The committee will next meet Feb. 10 on the sidelines of the National Association of Regulatory Utility Commissioners' winter policy summit, where it will discuss the stakeholder responses and the potential need for FERC or independent analyses.

New Mexico's Byrd Joins RSC

The RSC welcomed Jefferson "Jeff" Byrd as its New Mexico representative. He replaces Pat Lyons, who left the regulatory arena last year.

A rancher and environmental engineer, Byrd won election in November to one of five seats on the New Mexico Public Regulation Commission. It's the first time he has held public office, following two unsuccessful runs at the U.S. House of Representatives. ■

— Tom Kleckner

January's Regional State Committee meeting | © *RTO Insider*

SPP

SPP Board of Directors/MC Briefs

Board Approves Modernized Cost-recovery Structure

NEW ORLEANS — SPP continued its effort to modernize its cost-recovery processes last week, agreeing to replace its broad single rate schedule with four targeted ones.

January's Board of Directors/Members Committee meeting | © *RTO Insider*

The Board of Directors approved the Schedule 1A Task Force's recommended preliminary designs during its regular quarterly meeting. The group's four rate schedules seek to better align beneficiaries with payers and include energy transactions in their design.

The new rate design was approved by the Markets and Operations Policy Committee two weeks prior. The task force will now draft Tariff language and bring it back for approval in April or July. It has targeted implementation by June 2021. (See "1A Task Force's Fee Schedules OK'd," *SPP Markets & Operations Policy Committee Briefs: Jan. 15, 2019*.)

SPP says its current cost-recovery mechanism is based on a two-decade-old structure "that no longer aligns with actual use of our system."

Under the new rate design, four rate schedules will replace the current one. Planning, scheduling and dispatch costs will be paid by transmission customers; financial administration costs by their users; market-clearing costs by virtual and real-time market participants; and markets facilitation by real-time market participants.

Evergy's John Olsen | © *RTO Insider*

The task force agreed to use a mix of demand and energy charges, with market costs recovered through energy changes and planning costs through demand. Much of the debate centered on scheduling and dispatch costs, energy billing determinants and financial instruments, said Evergy's John Olsen, the task force chair.

"I don't think we made anyone perfectly happy throughout the process, but it was a great compromise," Olsen said.

Oklahoma Gas & Electric's Greg McAuley abstained from the Members Committee vote on the issue, saying his company wants to see independent generators paying their share of the costs.

"We don't see Tariff language dealing specifically with that," he said. "We thought this was a missed opportunity to address what we see as an inequity that exists now. We've got more generation in our [interconnection] queue than we've got load. This was an opportunity to take that uncommitted new generation and give it a stake in this infrastructure that accommodates them.

OG&E's Greg McAuley and Director Phyllis Bernard share a microphone. | © *RTO Insider*

"We think it's a move in the right direction. We'll be watching and participating moving forward," McAuley said.

David Osburn, general manager of the Oklahoma Municipal Power Authority, said he agreed in principle with the proposal, as market participants would be paying more of their share of the costs.

"Our concern was going from one charge to four. We just want to be careful not to make something more complex than it should be," Osburn said. "As the real numbers develop, hopefully, we'll get a better comfort level as we move forward. Being a small organization, we have difficulty covering all these activities."

The task force was only formed last summer, but some of the work goes back several years, said Director Bruce Scherr, chair of the Finance Committee.

"We put a very significant stake in the ground here," he said. "We can make refinements as we go through time. That's not trivial, because it will require new filings at FERC. But it's an important step in the right direction."

Brown: SPP's Prime Focus is RC Services in West

SPP CEO Nick Brown | © *RTO Insider*

SPP CEO Nick Brown told the board and members that the grid operator's primary goal this year will be to successfully implement reliability coordination services in the Western Interconnection.

The RTO recently said it remains on track to be certified in August and is scheduled to go live with its RC services on Dec. 3. It has signed RC contracts with about 12% of the load once served by Peak Reliability, which announced last year it would cease to exist by the end of this year. (See *CAISO RC Wins Most of the West*.)

"Entities coming and going in our footprint is not a new thing for us," Brown said, referring to the additions of Nebraska public utilities and the Integrated System, and Entergy's move to MISO. "It's a new thing for entities in the West and for NERC. We're very aware of NERC's anxiety for taking what was performed under

SPP

a single entity's umbrella and bifurcating that under multiple entities."

Also foremost on Brown's mind is the Value and Affordability Task Force, which held its first "quasi-closed" session — members were allowed one representative to attend — on Jan. 30. Reporting directly to the board and led by Board Chair Larry Altenbaumer, the group is reviewing the cost recovery of transmission investments and the ongoing benefit being delivered from that investment and SPP's operation.

"There's significant confidential information that will have to be shared, if that group is to do its job," Brown told members. "It makes me nervous. I compete with every one of you for personnel."

Other SPP goals include:

- Replacing the organization's settlement system, which processes the more than $20 billion in annual revenues that flow through the markets. The project is behind schedule, but staff believe they can begin testing the system in May.
- Improving generation interconnection processes.
- Seeing conclusion of the work of the Schedule 1A Task Force and the Holistic Integrated Tariff Team, which are seeking to improve SPP's transmission planning, markets and cost-allocation processes.

Members Increase Board's Compensation

During a special Members Committee meeting, members sided with a Corporate Governance Committee recommendation and increased the board's compensation for meeting attendance.

Directors will see their annual retainer raised from $30,000 to $50,000. Attendance at required meetings and board dinners will yield a total annual compensation increase from $81,000 to $101,500.

Brown said the CGC based its recommendation on recent research from NERC, two-year-old data from the ISO/RTO Council and a national association of board directors. On an annualized basis, he said, SPP directors' compensation fell around the 50th percentile of the market.

Brown said SPP will work with compensation consultant Mercer this year to do a "full-blown" study.

Members also elected three representatives to three-year terms on the Members Committee: American Electric Power's Peggy Simmons, representing the investor-owned utility sector; and Basin Electric Power Cooperative's Tom Christensen and Tri-County Electric Cooperative's Zac Perkins, representing the cooperative sector.

Perkins won a contest vote for his seat against Midwest Energy's Bill Dowling, who was nominated from the floor without discussion.

GreenHat Energy Situation Unlikely in SPP, Director Says

Scherr told the board and members that an event similar to GreenHat Energy's massive default on financial transmission rights in PJM's market is unlikely to happen in SPP. PJM now estimates the event could cost its members more than $430 million. (See *PJM: FERC Order Could Boost GreenHat Default by $300M*.)

"There are significant differences in the SPP markets, such as the level of congestion and structure of [FTR] products, which reduce the likelihood of this magnitude," he said.

Scherr said he is heartened by the Credit Practices Working Group and Market Monitoring Unit's oversight of the grid operator's FTR markets.

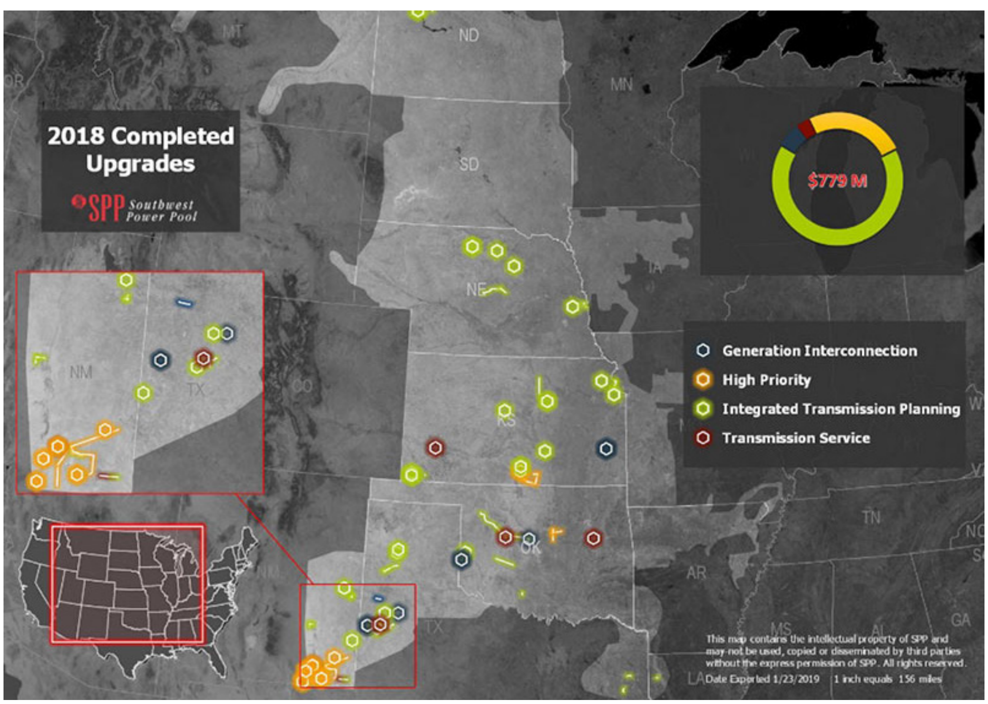
Board Approves $1.8B in Transmission Projects

The board passed a consent agenda that included the 2019 SPP Transmission Expansion Plan (STEP) *report*, previously endorsed by the Markets and Operations Policy Committee. The report anticipates that an estimated $1.8 billion of projects will be built over the next five years in 13 states.

Also approved as part of the agenda:

- Revision to SPP's bylaws to allow any member to appeal to the board with a written request any action taken or recommended by an organizational group.
- A Tariff revision (*TWG RR237*) that removes duplicative or unnecessary language in the SPP criteria to make it consistent with NERC Standard TPL-001-4's requirements and account for the differences between NERC's requirements and SPP's Tariff.
- East River Electric Power Cooperative's sponsored upgrades of a new 115-kV line and a 115/69-kV transformer near Aberdeen, S.D. The project will be a creditable upgrade eligible for incremental long-term congestion rights or cost recovery through the Tariff's Attachment Z2.
- Modification of Westar Energy's notification to construct a 345/138-kV transformer, requiring all elements and conductor to have an emergency rating of 440 MVA. The original requirement was 492 MVA. ■

— Tom Kleckner



2018 completed upgrades | *SPP*

SPP

Xcel Again Betters Year-end Guidance

Xcel Energy last week reported that it once again met or exceeded its earnings guidance, *posting* year-end profits of $1.26 billion ($2.47/share), compared to $1.15 billion ($2.25/share) in 2017.

It was the 14th straight year the Minneapolis-based company had exceeded its own guidance.

Xcel's fourth-quarter earnings were $215 million ($0.42/share), up from $189 million ($0.37/share) a year earlier. That met Zacks Investment Research's consensus forecast.

Xcel continues to focus its efforts on clean energy. | *Xcel Energy*

Oil and gas production and strong economies in Xcel subsidiary Southwestern Public Service's footprint drove a 1.3% increase in energy sales. The company expects flat sales in 2019, but it reaffirmed its 2019 earnings guidance of $2.55 to $2.65/share.

CEO Ben Fowke | *Xcel Energy*

CEO Ben Fowke said the company's clean energy transition continues to be a strategic priority. He said the company's steel-for-fuel strategy has achieved a 39% reduction in carbon emission from 2005 levels. The company has set an 80% carbon-reduction target by 2030 and a goal of 100% carbon-free energy by 2050.

"Technologies have come a long way in the last 10 years, and it gives me confidence that our 100% carbon-free bill can be met as well," Fowke said during a Jan. 31 conference call with financial analysts.

Xcel secured approval for more than 1 GW of new wind in Texas and New Mexico and 300 MW of wind in South Dakota. It completed construction of its 600-MW Rush Creek wind farm in Colorado and also acquired 70 MW of repowered wind energy.

Investors on Wall Street applauded Xcel's performance, driving the company's share price up $1.22 to $52.14, a 2.4% increase. Xcel hit an all-time closing high of $53.68/share in December. ■

— Tom Kleckner

Company Briefs

FERC OKs ITC Tx Purchase

FERC last week approved ITC Holdings' $36.8 million acquisition of transmission facilities servicing Dearborn Industrial Generation's 710-MW natural gas generator in Dearborn, Mich.

The power plant, which originally powered the Ford River Rouge Complex and an AK Steel plant, now has market-based rate authority and sells into the MISO markets. Dearborn Generation is a subsidiary of CMS Energy.

The commission said the transaction would not have an adverse effect on horizontal or vertical competition.

More: *EC18-116, EC18-144*

AWEA: 2018 Record Year for Corporate Wind PPAs

Non-utility customers, such as AT&T, Walmart, ExxonMobil and Shell Energy, purchased a record 4,203 MW of wind power capacity in 2018 through power purchase agreements, according to the American Wind Energy Association's quarterly report, released last week. That was 66% higher than the previous record set in 2015, the group said.

Utilities signed contracts for 4,304 MW of wind power in 2018, which, when combined with non-utility purchases, reached the highest level on record for overall PPA activity with 8,507 MW in 2018, AWEA said.

"A rapidly growing number of big brands and utilities clearly understand that for American consumers, it's no longer enough for energy to be affordable and reliable, it must also be clean," AWEA CEO Tom Kiernan said. "Businesses are responding to their customers by seeking out the lowest-cost clean energy they can find to power their products and operations reliably."

More: *American Wind Energy Association*

Foley & Lardner Adds 2 to Energy Industry Team

Foley & Lardner last week announced that Tom Hoffmann and Darin Lowder have joined its Business Law Department and Finance Practice Group as partners in its D.C. office, where they are also members of the Energy Industry Team.

Both come from Ballard Spahr, where Hoffmann was the co-practice leader of the firm's Energy and Project Finance Group, and Lowder was a partner focusing on energy, project finance, project development, and related tax and public sector financing tools.

Before Ballard Spahr, Hoffmann was president of International Energy Partners, a development and investment company, and Lowder worked for companies in the real estate, financial services and nonprofit sectors, counseling them on issues related to renewable energy and conventional generation.

More: *Foley & Lardner*

ATC Announces 2 Promotions

American Transmission Co. last week announced that it has promoted Andy Dolan to vice president of system planning and Debbie Masbruch to director of business administrative services.

Dolan, one of ATC's founding employees, will be responsible for the reliability, interconnection, and economic and strategic planning of the company's transmission system. Masbruch will be responsible for the supply chain, project controls, the company's Center of Excellence and business relationship managers, and its data analytics teams.

More: *American Transmission Co.*

GE Consolidates Renewable Assets, Reports Increased Revenue

General Electric last week announced it has expanded GE Renewable Energy to house all of the company's renewable energy and grid assets: solar, storage, wind and hydropower.

The company reported that annual revenue for the new segment, totaling $3.4 billion, was up 28% year-over-year. Overall revenue was also higher than expected, at $33.3 billion.

"We have more work to do, but I'm encouraged by the changes we're making to strengthen GE and create value for our shareholders, customers and employees," CEO H. Lawrence Culp Jr. said in a statement.

More: *Greentech Media*

Developers Granted Abandonment Incentives for PJM Tx Upgrades

The developers of a $182.5 million transmission project to address reliability violations expected from the deactivation of 4,000 MW of nuclear generation will be permitted to recover 100% of prudently incurred costs should the project be canceled for reasons beyond their control, FERC ruled last week.

The commission acted at the requests of Duquesne Light, FirstEnergy's Mid-Atlantic Interstate Transmission and West Penn Power, which were selected by PJM to reconductor 47.5 miles of transmission and replace existing 138/500-kV transformers and substation components. The upgrades will address 140 reliability criteria violations anticipated from the deactivation of the Perry nuclear plant, Davis-Besse Unit 1, and Beaver Valley Units 1 and 2 between May 31, 2020, and Oct. 31, 2021.

Duquesne also was permitted to include 100% of construction work in progress in the company's rate base during development and construction of its $38.4 million share of the project. Ruling on FirstEnergy's request, the commission agreed that the project "faces substantial risks and challenges because it will cross several jurisdictions; involve significant costs; require multiple layers of governmental approvals; and will require coordination among multiple transmission owners."

More: *ER19-303*; *ER19-297*

PUCO Chairman Haque to Resign, Join PJM in March

PJM has appointed Public Utilities Commission of Ohio Chairman Asim Haque as its executive director of strategic policy and external affairs, effective March 11, the RTO announced Monday.

Haque will advise PJM on energy policy matters and be responsible for engaging and fostering relationships with members of state and federal government in the RTO's territory.

"Asim is respected for his astute insights into policy and practical questions facing our industry," PJM General Counsel Vince Duane said.

More: *PJM*

Federal Briefs

FERC Proposes Expedited Hydro Licensing Process

FERC last week issued a Notice of Proposed Rulemaking that would expedite the issuance of original hydropower licenses for certain qualifying facilities at existing non-powered dams and closed-loop pumped storage projects (*RM19-6*).

The commission said the process described in the NOPR would ensure a final licensing decision no later than two years after receipt of a completed application. Comments on the NOPR are due 30 days after its publication in the Federal Register.

The proposal is part of FERC's implementation of the America's Water Infrastructure Act of 2018, signed into law by President Trump in October.

More: *FERC*

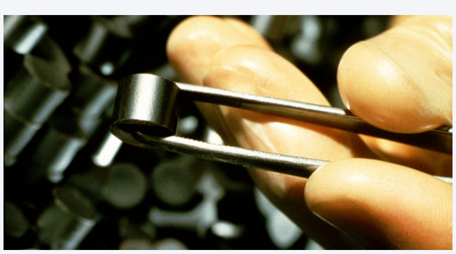
Bloomberg: White House Considering Lummis for Interior

White House officials are seriously considering former Rep. **Cynthia Lummis** (R-Wyo.) to serve as the next secretary of the interior, people familiar with the deliberations told Bloomberg last week.

Lummis served four terms in the House of Representatives, from 2009 to 2017, and was an unabashed champion of oil, gas and coal development. She did not seek re-election in 2016. Prior to serving in the House, she served in both houses of Wyoming's State Legislature, and as the state's treasurer.

More: *Bloomberg*

DOE Awards $111M for Accident-tolerant Nuke Fuel Development



The Department of Energy last week announced that its Office of Nuclear Energy has awarded $111.2 million to General Electric, Westinghouse Electric and Framatome to develop accident-tolerant fuels (ATF).

"The improved heat tolerance of ATF contributes to significantly improved reactor safety and security," the department said. "ATF also improve economics due to improved heat tolerances and increased agility to power reactors up and down while staying within safety margins."

Each company has been developing its own unique formula of ATF. GE, for example, has been developing iron chromium aluminum cladding for fuel rods, trademarked as IronClad.

More: *Department of Energy*

DOE Secretly Shipped Weapons-grade Plutonium Across US

The Department of Energy secretly shipped weapons-grade plutonium from South Carolina to a nuclear security site in Nevada months ago, enraging the latter state's officials.

The Justice Department notified a federal judge in Reno about the shipment as part of a federal court case in which Nevada was trying to block the move, first announced in August last year. The Trump administration did not disclose when exactly the shipment took place — only that it was before Nevada first brought the case in November.

Nevada Gov. Steve Sisolak (D) said he's "beyond outraged by this completely unacceptable deception." Sen. Jacky Rosen (D) called the government's move "deceitful and unethical," while Nevada's other senator, Catherine Cortez Masto, said she would demand department officials come to her office to explain how they made the "reckless decision" in such "bad faith."

More: *The Associated Press*; *The Hill*

Castor Divests from Mutual Fund After Report

Rep. **Kathy Castor** (D-Fla.), chair of the new House Select Committee on the Climate Crisis, sold her shares in a mutual fund with holdings in utility companies after Sludge, a news website that tracks money in politics, published an article about her investment.

Castor "divested from the Franklin Utilities Fund to build confidence in her leadership of the Select Committee on the Climate Crisis," Steven Angotti, Castor's press secretary, said in an email to Sludge.

As part of her chairmanship, Castor said she would not accept any campaign donations from the fossil fuel companies. She said the investment, worth between $50,001 and $100,000 and held in a joint retirement account with her husband, did not "enter into my consideration of public policy."

More: *Sludge*

FERC OKs SPS Revisions to Tx Rates

FERC last week granted Southwestern Public Service's proposed revisions to its transmission formula rate template and several waiver requests. However, the commission said its preliminary analysis of the changes indicated they may be unjust and reasonable, and it set the revisions for further settlement procedures.

Public Service Company of Colorado submitted the revisions on sister company SPS' behalf in November. The filing updated the transmission depreciation rates used to calculate wholesale transmission rates; revised the template's base plan upgrade revenue requirement calculation to use a weighted average transmission depreciation rate; and made several changes to SPS' accumulated deferred income taxes calculation.

SPS asserted the proposed revisions to the transmission depreciation rates were consistent with FERC Order 618, which requires utilities use methods of depreciation accounting that "allocate the cost of utility property over its useful service life in a systematic and rational manner." It said the single depreciation rate it currently uses for base plan upgrade projects is no longer representative of actual transmission depreciation expenses, and contended that a weighted average depreciation rate provides a more accurate measure of the expense.

More: *ER19-404*

PSCo's Revisions to GI Processes Rejected

FERC last week rejected Public Service Company of Colorado's (PSCo) attempt to reform its interconnection request by revising its large generator interconnection procedures (LGIP) and large generator interconnection agreement (LGIA).

FERC issued the order without prejudice and complimented PSCo on its efforts to address the backlog of 23 GW of generation interconnection requests in its LGIP queue. It encouraged the Xcel Energy subsidiary to refile a modified proposal incorporating its guidance.

The commission found that PSCo's revised Tariff language regarding the cost allocation of network upgrades was not clear and that it had not demonstrated that its proposed financial milestone and site-control requirements were consistent with or superior to the pro forma LGIP.

More: *ER19-366*

FERC Accepts Mor-Gran-Sou's Formula Rate

FERC accepted a 50-basis-point adder to Mor-Gran-Sou Electric Cooperative's base return on equity as it joined SPP and placed its transmission facilities under the RTO's functional control last week.

But the commission said SPP's proposed Tariff revisions related to the integration raised "issues of material fact that cannot be resolved" based on the information before it and would be more appropriately addressed in the hearing and settlement judge procedures.

SPP filed a request in November to recover Mor-Gran-Sou's transmission service revenues for its facilities. The RTO placed the co-op, a member of Basin Electric Power Cooperative serving south central North Dakota, in its Upper Missouri Zone (Zone 19), home to the Integrated System and several other entities.

More: *ER19-456*

State Briefs

ARIZONA

APS Attributes Rate Reduction to Low Gas Prices, EIM

Arizona Public Service last week announced an $80 million rate reduction — about $3/month for the average customer — because of low natural gas prices and the utility's participation in the Western Energy Imbalance Market.

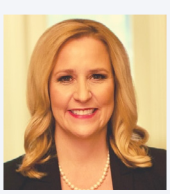
The company is not being affected much by the current upswing in gas prices tied to the Midwest cold snap because it already agreed to purchase fuel today at a set price years ago, according to Brad Albert, vice president of resource management for APS.

Participating in the EIM saved APS and its customers $45 million in 2018, Albert said. On 81 days in the past year, APS was actually paid to take excess power from other markets, mostly California, he said.

More: *The Arizona Republic*

ARKANSAS

Rutledge Joins Settlement with OG&E over Rate Increase



Attorney General **Leslie Rutledge** last week announced a settlement with Oklahoma Gas and Electric to reduce the utility's requested $6.4 million rate increase by more than $3.1 million.

Rutledge joined the settlement with Public Service Commission staff and the Arkansas River Valley Energy Consumers group. OG&E will be required to report and document how its proposed investments in grid modernization will benefit all of its customers, and how its proposed investments in transmission assets will be reimbursed by other states through SPP.

A hearing on the settlement is set for Feb. 7, but all parties have requested that the PSC waive the hearing, Rutledge said. The commission is required to rule by March 12, and the increase will be effective with April bills.

More: *Attorney General Leslie Rutledge*

BRITISH COLUMBIA

BC Hydro Awarded $90M in Dam Contracts Without Bids

BC Hydro granted by far the largest Site C dam direct award contract to a construction company belonging to McLeod Lake Indian Band, which has spoken out widely in support of the project, according to documents The Narwhal obtained through a Freedom of Information request.

Duz Cho Construction, a Chetwynd-based company with roots in the oil patch and mining industry, received a $29.5 million (Canadian) direct contract for "site preparation" work in 2016 on the Peace River's south bank, according to the documents.

The contract was among 38 Site C project direct award contracts worth close to $90 million that BC Hydro granted from March 2016 to October 2018, including contracts to numbered companies, the documents show.

The New West Partnership Trade Agreement among Canada's western provinces mandates that any services or construction contract greater than $100,000 should be issued through open tender unless a public agency can prove an urgent or specialized need. BC Hydro's FOI response was titled, "Direct Award Allowed under New West Partnership Agreement."

More: *The Narwhal*

MAINE

Legislature Considers Bills to Restore Net Metering

The Legislature's Energy Utilities and Technology Committee last week held a public hearing on two bills that would restore net metering in the state, after former Gov. Paul LePage (R) ordered the Public Utilities Commission to phase it out.

Both bills would repeal the PUC's "gross metering" policy, which allows utilities to track how much solar power is produced by an array and then charge a fee on that production, even when the electricity never leaves the house.

But they differ in how they would reinstitute net metering. One, proposed by Rep. Seth Berry (D), would temporarily restore it to the way it was in 2017 — with homeowners receiving a full credit on their bills for every excess kilowatt-hour of solar energy fed into the grid — while the Legislature develops a more comprehensive solar energy policy. The other, introduced by Rep. Beth O'Connor (R), would allow customers to continue entering into net metering arrangements through Dec. 31, but then cap the incentives for rooftop solar customers at 6 cents/kWh.

More: *Portland Press Herald*

MANITOBA

Manitoba Hydro Sets Record for Power Use During Cold Snap

Manitoba Hydro set a record for electricity use Jan. 30, with peak load at 7 a.m. at 4,924 MW, amid brutal cold.

The high temperature at the Winnipeg airport that day was -31 degrees Celsius (-23.8 F), about 20 degrees lower than the average high for that date.

The previous record, set Jan. 13, 2017, was 4,801 MW. The average peak load over the past five years for a January day is 4, 680 MW, according to Manitoba Hydro.

More: *CBC News*

MICHIGAN

Whitmer Calls for Review of Energy Supply, Preparedness

Following a fire at a Consumers Energy compressor station in Macomb County that resulted in industry and homeowners being requested to cut back their natural gas usage during record-breaking cold last week, **Gov. Gretchen Whitmer** asked the Public Service Commission to conduct a review of the state's energy supply and preparedness.

"Today, I'm also asking the Public Service Commission for an initial statewide review of supply and deliverability of natural gas, electricity and propane and contingency planning," Whitmer said at the state emergency operations center at State Police headquarters. "It's important that we get a handle on what's happened here." She requested a preliminary report by July 1.

The cold brought MISO's eighth maximum generation event and multiple appeals for conservation from utilities in the northern portions of the RTO's footprint. (See related story, *MISO Maintains Reliability Through Arctic Midwest Temps*.)

More: *Detroit Free Press*

MISSISSIPPI

PSC Commissioner Announces Candidacy for Secretary of State

Public Service Commissioner **Sam Britton** last week announced he would run for secretary of state in November's statewide elections.

Britton is serving in his first term as commissioner and aims to replace current Secretary of State Delbert Hosemann, who is running for lieutenant governor. He will face State Sen. Michael Watson in the Republican primary.

"Delbert has set the bar high for anyone who follows behind him, and everybody will be judged on the performance of Delbert Hosemann as you move into the future," Britton told reporters at the Capitol last week. "Yet more things are to be done in this state."

More: *Mississippi Today*

MISSOURI

City Utilities Cancels Plans for 2nd Solar Farm at Airport

City Utilities of Springfield last week said that it will not move forward on a proposed second solar farm near the Springfield-Branson National Airport, as the cost of electricity would have been too expensive for ratepayers.

CU said that 15 energy companies submitted bids for the 3-MW project, saying they would charge 5 to 12 cents/kWh.

More: *Springfield News-Leader*

MONTANA

DEQ: Colstrip Cleanup to Cost up to $700M

Cleaning up the Colstrip coal-fired plant's coal ash ponds will cost as much as $700 million, maybe more, according to a legislative memo from the Department of Environmental Quality.

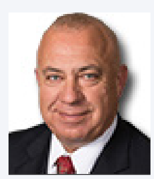
The estimates came from Colstrip's largest stakeholders, Talen Energy, which operates the plant, and Puget Sound energy, which has the largest ownership share.

The ponds have leaked contaminants into the local groundwater for decades. An estimated 200 million gallons of contaminated water has been seeping each year for 30 years, rendering the groundwater undrinkable for the Colstrip community of about 2,300.

More: *Billings Gazette*

NEBRASKA

Committee Considers Bill to Regulate Wind Turbine Placement



The Legislature's Government, Military and Veterans Affairs Committee last week held a hearing to consider a bill that would put in place a two-year requirement that wind turbines be located at least 3 miles from a home.

The temporary requirement of the bill, proposed by **Sen. Tom Brewer**, would allow counties time to develop their own regulations for turbines' placement, noise and decommissioning.

Brewer said he introduced the bill on behalf of those who "are forced to live next to these facilities and have no say in their existence. ... There has to be some way of protecting those adjoining landowners. You're going to look at this wind tower for the rest of your life and the rest of your kids' lives."

More: *Omaha World-Herald*

NEW MEXICO

State Joins US Climate Alliance

Gov. Michelle Lujan Grisham last week announced the state would join the U.S. Climate Alliance, making it the 19th member of the group of states committed to following the 2015 Paris Agreement on climate change.

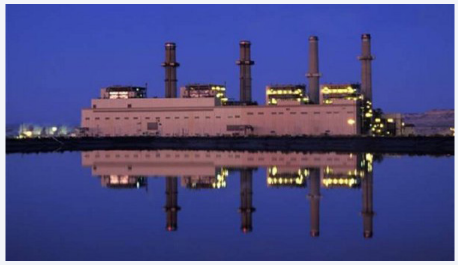
The agreement, from which President Trump has said he intends to withdraw the U.S., aims to hold the increase in the global average temperature to well below 2 degrees Celsius above pre-industrial levels. The state will try to reduce its emissions by 26% below 2005 levels by 2025, the U.S.' goal under the agreement.

Lujan Grisham also ordered the creation of a Climate Change Task Force, and for state agencies to develop a statewide, enforceable regulatory framework to reduce methane emissions and prevent further waste from new and existing sources in the oil-and-gas sector.

More: *U.S. Climate Alliance*

Senators Introduce Retail Choice Bill

Sens. Jeff Steinborn and Benny Shendo, both Democrats, introduced a bill last week that would open up the state's retail electricity markets to competition.



Senate Bill 374, or the "Local Choice Energy Act," would allow local communities to purchase energy from whatever source they want.

"It would allow local governments to tap into the market," Steinborn said, "to get the best deal they can on energy, to get the greenest energy they can, if that's their desire, and to create great local jobs in the process."

More: *Santa Fe New Mexican*

PRC Votes to Begin Hearings on San Juan Abandonment

The Public Regulation Commission last week voted 5-0 to immediately begin public hearings on Public Service Company of New Mexico's plans to abandon the coal-fired San Juan Generating Station near Farmington.

PNM had asked the commission to wait until mid-2019 to give the utility time to prepare a detailed plan for abandoning the plant and replacing that electricity with alternative resources.

But commissioners said PNM and three of the other four plant co-owners already firmly stated their intent in June and July 2018 to abandon San Juan. The decision to cease operating the plant in 2022 represented a "triggering event" that requires the PRC to immediately review the issue with public input, according to PRC General Counsel Michael Smith.

More: *Albuquerque Journal*

OREGON

Democrats Unveil Cap-and-trade Bill

Democratic legislators last week introduced a 98-page bill that would implement a cap-and-trade system in the state, with a goal of reducing emissions by 45% below 1990 levels by 2035.

Under the bill, the state will set a cap on greenhouse gas emissions beginning in 2021 and sell to the state's largest polluters — those with more than 25,000 tons of carbon-equivalent emissions a year — an allowance for each ton of pollution they emit.

Utilities such as Pacific Power and Portland General Electric wouldn't have to purchase credits for each ton of pollution they emit until 2030. They would instead be given allowances for free until then. "Given that our customers are already paying for investments in clean energy to bring our emissions down, we believe we should have direct allocation," PGE spokesman Steve Corson said.

More: *Oregon Public Broadcasting*