# RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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May 28, 2019

# California Utilities Prepare as Fire Season Looms

## *Widespread Shutoffs Planned During High Winds*

*By Hudson Sangree*

SACRAMENTO, Calif. — Utilities are bracing for another fire season as the state heads into summer, but officials say troubling questions remain about how to gauge their level of readiness.

Pacific Gas and Electric said widespread power shutdowns will be a key part of its strategy following two years of catastrophic fires fueled by high winds and dry vegetation. The Camp Fire, sparked by PG&E equipment Nov. 8, was the deadliest and most destructive in state history.

The state's two other large investor-owned utilities, San Diego Gas & Electric and Southern California Edison, have employed strategic shutdowns for years, but this could be the first season that tactics used in drier Southern California are regularly deployed in relatively rainy Northern California.

PG&E has used intentional blackouts only once before, when it first started the practice last October. (See *Fire Season Becomes Blackout Time in California*.)

"We will only turn off power for public safety and only as a last resort to keep our customers and communities safe," PG&E said in a *news release*, responding to controversy surrounding the program.

The Camp Fire and a rash of deadly fires in 2017 led PG&E to file for bankruptcy in January, shake up its leadership and boost fire-prevention practices. (See *PG&E Names New CEO, Board Members*.)

The utility's Public Safety Power Shutoff program now includes roughly 25,000 miles of distribution lines, up from 7,000 last year, and about 5,500 miles of transmission lines, including 500-kV lines, an increase from 373 miles at 70 kV and below in 2018. The *plan* af-

*Continued on page 9*



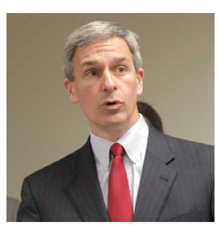
# Va. Group Seeks End to Dominion Monopoly

*By Christen Smith*

A newly minted energy policy group in Virginia has set its sights on busting up the commonwealth's dominant utility companies — Dominion Energy and Appalachian Power — in favor of a deregulated electricity market.

The *Virginia Energy Reform Coalition* (VERC) features policy experts from across the ideological spectrum united against what it considers wasteful infrastructure spending funded by ever-increasing electricity rates.

"Moving from Virginia's 100-year-old government-regulated electricity market to a 21st-century free market will finally put families and businesses in control of their electricity-buying decisions so they can lower their own prices simply by shopping around," *said* former Virginia Attorney General Ken



Ken Cuccinelli | *Piedmont Environmental Council*

Cuccinelli, director of the Regulatory Action Center of the libertarian FreedomWorks Foundation, one of VERC's nine member organizations. "Shrinking the control of the government-imposed electricity monopoly means more citizens' control, more choices, more innovation and lower prices."

*RTO Insider* contacted each of Virginia's legislative caucuses to gauge lawmakers' appetite for electricity deregulation but received no response. Staffers for the respective Commerce and Labor committees declined to comment.

*Continued on page 30*

# 'Grid Transformation Day' Highlights ISO-NE Challenges

WESTBOROUGH, Mass. — More than 150 people attended ISO-NE's first Grid Transformation Day last week to hear about the speed of the change overtaking the power industry — and the breadth of resources needed to accommodate it.

Here's some of what we heard.

### Dealing with Outdated Data

Stephen Rourke, ISO-NE vice president for system planning, said the industry is changing so fast that some of the RTO's statistics for last month are already significantly misleading.

One example: The figure of 1,381 MW of battery storage in the interconnection queue

*Continued on page 16*



# Overheard at AWEA WINDPOWER 2019


Houston's George R. Brown Convention Center hosted WINDPOWER 2019. (p.4) | © *RTO Insider*

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# In this week's issue

ERO Insider
Your Eyes and Ears on the Electric Reliability Organization
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# NERC Panel Delays Action on BAL Standard Request

## *What to Do When ACE Conflicts with Interconnection Frequency?*

*By Rich Heidorn Jr.*


Arizona Public Service raised questions about how balancing authorities should react when their area control error (ACE) is at odds with an interconnection's frequency. | *Arizona Public Service*

The NERC Standards Committee on Wednesday postponed action on Arizona Public Service's request to amend BAL-002-3 (Disturbance Control Standard — Contingency reserve for recovery from a balancing contingency event) after several members said they wanted to add the technical justification for its rejection to the record.

APS' standards authorization request (SAR) *proposed* that compliance with BAL-002-2 requirement R1 would be reached once interconnection frequency has recovered, saying the change was needed to prevent the recovery of one event from contributing to the creation of another event.

Asked by the SC to provide a technical review, the Operating Committee in March recommended rejection of the SAR, citing advice from its the Resources Subcommittee (RS). "The recommended modification of R1.1 of this standard to include interconnection frequency assessment will modify the original intent of [the] standard, which is the demonstration of the deployment of reserves to recover from reportable balancing contingency events (RBCEs)," the OC said, adding, "The concerns raised in this SAR can be addressed by other means."

Sean Bodkin, NERC compliance policy manager for Dominion Resources Services, asked for the delay, saying the technical reasons for the rejection should be added to the record. Other committee members also sought additional information on the "other means" cited by the OC.

"I'm not a BAL expert, but it looked like [APS] had a legitimate concern," said Steve Rueckert, director of standards for the Western Electricity Coordinating Council.

Duke Energy Carolinas' Tom Pruitt, chair of the RS, said there are simpler and more effective solutions to the situation identified by APS.

"There is an option to go through compliance guidance and develop a compliance guidance document. … There is an option for a BA [balancing authority] with the existing standard to simply execute an emergency assistance agreement with one of its neighbors for this situation. No modification of the standard at all is needed…

"The bottom line is, [under the SAR,] the BA would be exempt from balancing his BA area and that goes right to the heart of the job of a balancing authority," Pruitt continued. "If he's not required to balance his BA, we're missing the boat here."

Gary Nolan, an APS regulatory compliance adviser who wrote the SAR, told the SC there were "some differences of opinion and some misunderstandings" of his company's concerns.

APS was not seeking to have a BA shirk its responsibilities, he said, but attempting to draw attention to a situation in which a BA's area control error (ACE) is low while the interconnection frequency is high.

"BAL-001 R2 has a balancing authority … responding to what the interconnection needs as opposed to what the balancing authority needs. … When [interconnection] frequency is high, a balancing authority is asked not to correct their ACE and make frequency worse but rather to — if their ACE is low, it's okay for them to remain low if [interconnection] frequency is high," he explained.

Nolan said BAL-002 could be read to direct a BA in that situation to "increase their generation — or possibly, if it gets to a point where they're very near to the deadline, they may need to shed load in order to recover their ACE in time. … Shedding load should be something we would be abhorrent to and not want to do. … That's not going to help the interconnection … when frequency is high."

"I get it, and I can see where there's an issue," Rueckert responded. "But we need to remember that the Standards Committee is not a technical committee; we're kind of a process committee, and I don't know that we should be making a decision on this SAR on technical terms. I think that is the RS and the OC."

Bodkin agreed. "I know I am completely unqualified to make any technical justification on the BAL standards and that's the reason I actually wanted to see the technical information from the RS in the record."

### Revised Standards Grading Tool Approved

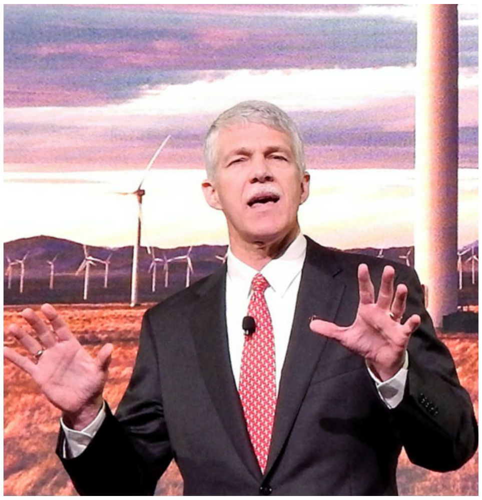
The SC also approved a revised ***Standards Grading Spreadsheet*** for the Periodic Review Standing Review Team to use in evaluating standards' requirements.

A working group formed last September revised ambiguous questions; eliminated duplicate questions; converted multipart questions into single questions; and added a reference section linking to source documents. It is the first update of the tool since its development in 2016.

However, the tool won't get used immediately because of the decision to suspend the review team's work until next year to avoid conflicts with the Standards Efficiency Review. (See "Standards Grading Process on 'Pause,'" *NERC Standards Committee Briefs: March 20, 2019*.) ■

# Overheard at AWEA WINDPOWER 2019

## *AWEA's Kiernan: 'Extraordinary Momentum,' but Challenges Exist*



Tom Kiernan | © *RTO Insider*

HOUSTON — American Wind Energy Association CEO Tom Kiernan kicked off last week's WINDPOWER 2019, the group's annual conference and trade show, by reeling off statistics on what he called the wind industry's "extraordinary momentum."

- More than 39 GW of wind capacity under construction or in advanced development.

  "That's like building [the wind capacity of] Texas, Iowa and California all over again," Kiernan said during his May 21 welcoming address.

- More than 97 GW of installed wind capacity nationwide through the first quarter of 2019, nearing the 100-GW mark.
- A record number of industry employees, with 114,000 "in all 50 states."
- $1 billion in annual economic support "to the communities we live in and work in," and another $250 million in annual land-use payments.

The industry still faces challenges, Kiernan acknowledged. The federal tax credits that helped fuel wind energy's growth begin to phase out in 2021. The industry faces uncertainty with laws that differ state by state and opposition to transmission development.

Kiernan said AWEA's agenda is focused on three programs: market design and transmission; a carbon price; and "scientific, evidence-based best practices" for siting turbines.

"We're seeking market rules in each RTO that will enable utility-scale wind and solar to compete fairly for all the services on the grid," he said. "We'd like to see FERC create a national transmission system to allow congestion and curtailment to decline."

Kiernan called for "meaningful legislation" that will create a carbon price. "Fortunately, politicians in D.C. and the states and around the world are talking about carbon more than ever before," he said.

"On the left, you have the Green New Deal. On the right, more productive conversations than we've ever had before," Kiernan said. "The future of our industry, the future of the clean grid, the future of our economy [and] the future of our planet will depend upon our success in working with our partners to implement solutions to these problems."

"This is an exciting time in the wind industry, with a tremendous development pipeline and 97 GW operating today," said Duke Energy Renewables President Rob Caldwell, AWEA's incoming board chair. "I feel really fortunate we will hit 100 GW in my term."

### Cost-effective Solutions

Kiernan moderated a panel of industry leaders that addressed how to ensure the industry


Houston's George R. Brown Convention Center hosted WINDPOWER 2019. | © *RTO Insider*

# AWEA WINDPOWER 2019

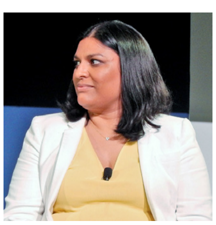
continues to provide cost-effective solutions and collaborates to continue its push toward a clean-energy economy.

Michael Skelly | © RTO Insider

"It now feels like in the renewable section, it's not a question of if, but a question of wind and how. When solar? When storage?" said Michael Skelly, late of Clean Line Energy and now a senior adviser with Lazard Asset Management. The wind industry is "right on top of the avoided cost, even without tax credits. With gas at $3/MMBtu or $4/MMBtu and if we can get the infrastructure, create the markets and properly site these projects, there's a tremendous amount of headroom."

Michael Garland | © RTO Insider

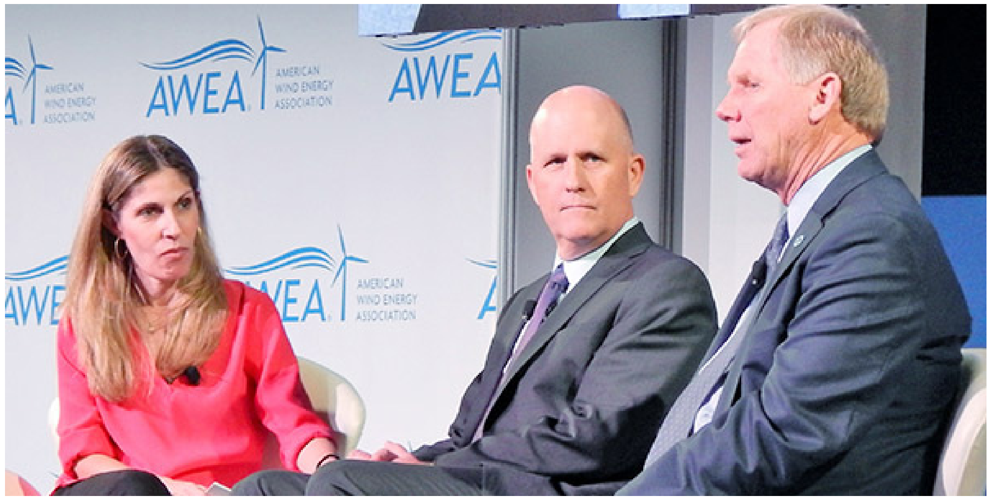
"We're not going to have an integrated grid until people focus on connectivity. We need a big system to move electrons a lot easier … so it doesn't matter where you are when you produce," Pattern Energy CEO Michael Garland said. "We as an industry have to get behind some of these initiatives in Congress, like the infrastructure bill, to support transmission. Most people don't want transmission in the backyard, and it only takes a few people to stop it. We're seeing resistance in solar right now that we didn't use to … it'll get more complex."



Neha Palmer | © RTO Insider

Google's head of energy strategy, Neha Palmer, said her company is seeking "viable mechanisms" to allow it to buy all the renewable power it needs. Google last year said it had reached its 100% renewable energy target, and it has completed more than 6 GW of renewable energy contracts.

"We want products to deliver renewable energy that helps us meet our goal. What we need now is power," she said. "We would like to see renewable generation tailored to provide that service. We all have this 100% goal. The next stage is matching our consumption with the supply."




E.ON North America COO Silvia Ortin Rios interviews outgoing AWEA Board Chair Steve Lockard (center), of TPI Composites, and Duke Energy Renewables President Rob Caldwell, the incoming chair. | © RTO Insider

"Power markets pull those things together," Skelly said. "If you have markets designed properly, and they work well, in theory, you ought to be able to place different resources where they work most efficiently."

## Researchers See Continued Opportunities

Research analysts shared their prognostications for the renewables industry, forecasting flat load growth but increased opportunities for both wind and solar energy.

Dan Shreve | © RTO Insider

Dan Shreve, head of global wind research for Wood Mackenzie, said wind energy is "absolutely maturing" and becoming a "bigger and bigger part of the energy puzzle."

"It's important to understand how wind fits in when you're talking about adding new generation into the power mix," he said, projecting flat load growth until 2040, when he expects 80 million electric vehicles to be on U.S. roadways. "It'll be quite a while to wait to make that larger impact for new power demands on the grid. We're looking at a levelized cost of electricity from wind, solar and natural gas. They're the favored elements. That massive adoption of energy renewables comes at a cost to someone, and here it's coal and nuclear."

Shreve foresees continued coal plant retirements, as does David Hostert, head of wind research for Bloomberg New Energy Finance.

"Half of the U.S. coal capacity is waiting for someone else to close so they can make their money," Hostert said. "There is a significant portion of capacity that is going to retire … and will create an opportunity as it needs to be replaced."

David Hostert | © RTO Insider

Max Cohen | © RTO Insider

IHS Associate Director Max Cohen sees wind and solar combining to capture 25% of the Lower 48's electric production by 2040, with solar accounting for 9% by itself. He projects coal's contributions to slip to 6%, with nuclear at 14%.

"We've been boosting solar more than wind," Cohen said, noting that the economics for wind energy are still "robust," even under a 20% production tax credit (PTC). "The economics slowly get better, but we see more solar installed every year than wind, starting in 2021. There's an upside for wind, but state policies can be heavy-handed in their approach" with their support for existing nuclear energy.

Ryan Wiser, a senior scientist at the Lawrence Berkeley National Lab, said the decreasing cost of wind energy — a 69% reduction over the last 10 years — is enough to withstand the PTC's phaseout by 2024. Those tax credits generate about $23/MW during a wind project's first decade of operation.

"There are a variety of mechanisms or tools for the wind industry or broader energy sector to press down the cost of wind ... even as penetration increases," Wiser said. "The gap after the current PTC cycle won't be long."

"We're hearing about single-digit [power purchase agreements] in ERCOT and SPP. Is that sustainable? Certainly not," Shreve said, noting that maturing technology means subsidies are no longer required to beat new gas generation prices. "The PTCs have absolutely been instrumental in driving demand in the U.S. market for 20-plus years. If you're talking about PPAs in the single digits, I think the [PTCs'] time has come."

"I hope it isn't the valley of death we all feared a few years ago," Hostert said.

### NARUC's Wagner Cautiously Approaches Change

Nick Wagner | © *RTO Insider*

Iowa Utilities Board Commissioner Nick Wagner, president of the National Association of Regulatory Utility Commissioners, injected a note of caution to the festivities as he detailed the group's focus on wind energy and the grid of the future.

"Nationally, we need to look at where it makes the most sense to put the resources, so we can reduce costs for everybody in the long run," Wagner said. "While it seems maybe this industry is in its glory days and things look good, ask coal, gas and nuclear what they have to offer, because they've been in this same situation. At one point, the nuclear industry thought it would get to the point where it's too cheap to measure.

"As we work through what we're doing, ask what could change. There are things that can change very quickly, and we need to be prepared for those things," he said.

Wagner proudly noted the leadership role his home state has played in the wind industry's development. He said U.S. Sen. Chuck Grassley (R-Iowa) considers himself the father of the PTCs and that the state was the first to have a renewable portfolio standard.

"That requirement was 115 MW. It's sort of a joke to us in Iowa," Wagner said, pointing to the state's current 9 GW of capacity.

He said Iowa's *advanced ratemaking* allows the state "to build generation with regulatory certainty," but he warned about major regulatory modifications during times of rapid change.

"I haven't been in the industry for 30 years, but people tell me this is one of the fastest changes we've seen," Wagner said. "I don't agree we need a new regulatory model, but we have to balance the interests between the consumers and utilities. We want to be careful that, as things change, we don't create a group of forgotten people with our decisions."

### Transmission Development a Key

Wagner said his state's success with renewables was "not anything Iowa did."

"The key to success is the RTOs," he said. "Iowa could not be able to generate as much [wind energy] as we do without the benefit of being involved with MISO."

Other speakers agreed with Wagner about the importance of RTOs and transmission development.

"There's a lot of interest in moving to 100% renewables," Shreve said. "It's going to be increasingly important for long-haul bulk transmission to support those endeavors, if they want to support resiliency."

"I think permitting is getting harder. We need more transmission to tap into the great resources around the country and move it around," Garland said.

"We really need to get more transmission to where the demand is," said Cohen, who expects transmission construction "ticking down."

"A lot of what's been done for transmission is hardening for weather or upgrading," he said. "We don't see a lot of transmission for wind. There's kind of a transmission fatigue. They've kind of built what they've built, and they're done."

### CLEANPOWER Hub to be Added to 2020 Event

AWEA welcomed nearly 8,000 attendees to its annual exhibition held May 20-23 at the George R. Brown Convention Center, with its largest exhibit hall in five years. Organizers are projecting 10,000 attendees at the 2020 event, which will be held June 1-4 in Denver.

The organization *announced* next year's event will include a new exhibition hub, called CLEANPOWER, that will bring together the utility-scale wind power, solar power and energy storage industries. Kiernan said AWEA is "throwing the doors open" in creating more opportunities for industry representatives to learn from each other and do business.

"We're seeing a lot of wind and solar on the grid just working really well together and helping to smooth out our variable production," Kiernan said. "We hear from many of you that you do as much solar business at WINDPOWER as you do wind business. We like that. CLEANPOWER will be your hub for clean power moving forward." ■

*— Tom Kleckner*


The WINDPOWER 2019 exhibition floor | © *RTO Insider*

# CAISO/WECC News

# RC West Moving Smoothly Toward July Handover

*By Hudson Sangree*

FOLSOM, Calif. — CAISO's RC West has been shadowing Peak Reliability as the ISO prepares to take over reliability coordinator functions throughout most of the West by the end of this year.

Tim Beach | © *RTO Insider*

The first phase of the two-month shadow operations — in which RC West employees have been mirroring Peak workers around the clock "in listening mode mainly" — will conclude soon, Tim Beach, RC West's director of operations, told the organization's Oversight Committee on May 21.

So far, *RC West* has been included on nearly every call, including an energy emergency alert (EEA) event just a few hours into the process, Beach said. "We're very happy about that," he said.

The next phase starts June 1, when RC West and Peak reverse roles. RC West employees will talk to balancing authorities, and Peak will step in "if they don't like how things are going," Beach said.

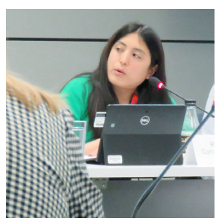
Nancy Traweek, executive director of system operations at CAISO, told the committee that the Western Electricity Coordinating Council had provisionally approved the ISO's bid to serve as an RC and that the matter is now in NERC's hands. NERC and WECC plan to observe RC West's shadow operations in the coming weeks, Traweek said.

Everything is going as planned, she told the committee.

RC West has secured agreements from 39 entities in the Western Interconnection, including Arizona Public Service, PacifiCorp and Seattle City Light. Its footprint stretches from the Canadian border into northern Baja California, and from the Pacific Ocean to the Rocky Mountains.

CAISO, SPP and BC Hydro will take over RC services from Peak Reliability, which last year decided to roll up its operations, on a staggered schedule throughout 2019. (See *RC Transition Fraught with Pitfalls, WECC Hears*.)

CAISO plans to become the RC for California and Baja California on July 1. BC Hydro will become the RC for most of British Columbia on Sept. 2. CAISO will then take over for many areas outside California on Nov. 1, while SPP will take responsibility for other parts of the West on Dec. 3.



Michelle Cathcart | © *RTO Insider*

The Oversight Committee had its first in-person meeting in March, when it elected its chair, Michelle Cathcart, vice president of transmission system operations with the Bonneville Power Administration, and vice chair, Steve Cobb, director of transmission and generation operations at Arizona's Salt River Project. (See *CAISO RC Oversight Committee Elects Leaders*.)

The *committee* plans to meet monthly throughout 2019. Its members represent the transmission owners and balancing authorities in RC West.

Last Tuesday's RC West Oversight Committee meeting took place at CAISO headquarters in Folsom, Calif. | © *RTO Insider*

At last week's meeting, Cathcart led a discussion about the possibility that WECC might revive its former RC operating committee and play a role in coordinating functions between the West's three new RCs. The proposal is in an early stage, she said.

The plan didn't appear to generate much enthusiasm among committee members, Cathcart noted. "I'm not hearing a lot of excitement in this room," she said. Last Tuesday's RC West Oversight Committee meeting took place at CAISO headquarters in Folsom, Calif. ■

## CAISO/WECC News

# PG&E Gets More Time to File Bankruptcy Plan

### *Establishes $100 Million Wildfire Aid Fund*

*By Hudson Sangree*

The federal judge overseeing PG&E Corp.'s bankruptcy case gave the company four more months to come up with a Chapter 11 reorganization plan at a hearing Wednesday.

Judge Dennis Montali, of the U.S. Bankruptcy Court in San Francisco, extended the 120-day period under which PG&E and its utility subsidiary Pacific Gas and Electric have exclusive rights to file a reorganization plan with the court.

Montali gave the companies through September to come up with a proposal, though he said he could shorten that time if he chose.

The companies filed for bankruptcy Jan. 29, citing at least $30 billion in liabilities for wildfires sparked by transmission and distribution lines. (See *PG&E Files for Bankruptcy*.) The 120-day exclusivity period was set to run out this week.

Montali's extension was a compromise. PG&E had asked for six more months in the hopes that California Gov. Gavin Newsom and the State Legislature might offer the state's investor-owned utilities wildfire liability relief later this year.

Lawyers representing wildfire victims had urged Montali to deny the extension, while creditors had recommended a four-month reprieve. The judge said he was inclined to grant PG&E's motion, but after hearing from the parties, he decided to accept the recommendation of the creditors' committee.

Tulips bloomed this spring in a neighborhood of Paradise, Calif., leveled by the Camp Fire last November. | © RTO Insider

"This judge has never been a fan of exclusivity but is a fan of practical consequences," Montali said. He explained he did not want to deal with competing reorganization plans that might be unworkable.

Montali also approved PG&E's creation of a $100 million fund to aid wildfire victims who lack housing or have other urgent needs. Many of those displaced by the November 2018 Camp Fire, the deadliest and most destructive in state history, are still living in tents and recreational vehicles in the destroyed town of Paradise.

One victims' lawyer said the fund was a ploy by PG&E to generate good will with the governor and lawmakers. PG&E and the state's other two large IOUs — Southern California Edison and San Diego Gas & Electric — want policymakers to lessen their wildfire liability under the state's strict liability standard, known as inverse condemnation.

PG&E is a "pariah in Sacramento" and needs help winning reforms, the plaintiffs' lawyer Robert Julian told the judge.

Julian said that in the same courthouse, Judge William Alsup is overseeing PG&E's criminal probation related to the 2010 San Bruno gas pipeline explosion and has ordered the company's new leaders to tour the devastation in Paradise. (See *PG&E Probed by Plaintiffs' Lawyers, SEC*.)

The California Department of Forestry and Fire Protection recently concluded PG&E's equipment had started the Camp Fire, which killed at least 85 people and destroyed nearly 19,000 structures. PG&E admitted weeks ago that a tower on its 100-year-old Caribou-Palermo line near Paradise had likely sparked the massive blaze. (See *Cal Fire Pins Deadly Camp Fire on PG&E*.)

"The only question is whether it's homicide or manslaughter in the Camp Fire because they knew that tower was going to fail," Julian said.

Montali said that as a bankruptcy judge, he could only approve or deny PG&E's request to establish the aid fund, and that he had no cause to deny it.

"You're saying, 'You get brownie points with the governor and Judge Alsup,'" Montali told Julian. "I don't care about that." ■


Mailboxes were often all that remained after the Camp Fire tore through Paradise, Calif., in November 2018. | © RTO Insider

# California Utilities Prepare as Fire Season Looms

## *Widespread Shutoffs Planned During High Winds*

*Continued from page 1*

fects potentially millions of customers in areas of elevated and extreme fire risk in the state's coastal regions, mountains and foothills.

### 'Uncharted Waters'

At a legislative hearing last week, representatives of the IOUs and an official from the California Public Utilities Commission outlined additional measures and shortcomings in the state's firefighting arsenal. The ***hearing*** of the Assembly Utilities and Energy Committee examined the IOU's ***wildfire mitigation plans*** filed with the CPUC earlier this year. (See ***PG&E Lays out Billion-dollar Wildfire Plan***.)

"We're in uncharted waters," committee chairman Chris Holden said.

Sumeet Singh

Sumeet Singh, in charge of PG&E's wildfire safety program, said the utility has installed 350 weather monitoring stations and plans to have 1,300 by 2020. It has installed 30 high-definition fire-detection cameras and is aiming for three times as many in 2019. The cameras allow firefighters to more quickly verify the location of a fire and monitor its progress before arriving on the scene.

"We're looking to get to 100 cameras by the end of this year" and to establish remote visual coverage of 90% of PG&E's high-risk fire areas in the next two to three years, he said.

PG&E said it is making a major push to inspect and harden its grid, which covers 70,000 square miles of Northern and Central California, or 42% of the state. A federal judge overseeing the utility's criminal probation in the San Bruno gas pipeline explosion case has put pressure on the company to increase inspections and fix problems. (See ***Judge Postpones Strict Probation Conditions for PG&E***.)

"We launched an aggressive inspection program [in] December of 2018, where we moved forward with inspecting all of our transmission infrastructure in the high-fire-risk areas, and we are near completion of doing the same for our distribution system," Singh told lawmakers. "This really entails an unprecedented level of effort that we have undertaken within our service territory."

Singh said PG&E has increased transmission line inspections by 130% this year and ramped up inspections of distribution lines by 400%, using a combination of drones, helicopters and workers. The company has turned to Silicon Valley to adopt machine learning to identify potential problems using powerline imaging, he said. (See ***Silicon Valley Tackles Wildfire Prevention***.)

The company is boosting its vegetation management, including clearing branches that overhang bare wires even when its vegetation clearances meet regulatory standards, he said. Half of all ignitions occur when overhanging vegetation contacts power lines, Singh said.

Replacing wooden poles with composite ones and strategically burying some power lines are among other grid hardening strategies, he said. The utility recently said it would bury new power lines in Paradise, as the town is rebuilt.

### Gaps in Expertise, Resources

PG&E's moves mirror those undertaken by SDG&E in the last decade after a series of devastating wind-driven fires in San Diego County in the early 2000s. The combination of 175 weather stations, more than 100 ***cameras***, de-energization and grid hardening has eliminated major wildfires sparked by power lines in the utility's service territory, said Brian D'Agostino, director of fire science and climate adaptation at SDG&E.

"Since we've implemented this plan over a decade ago, we have not seen a catastrophic wildfire ignited by electrical equipment across our region," D'Agostino told the committee.

The company has spent $1.4 billion in its effort and is continuing to improve, he said. Expanding the use of easements as firebreaks is a current focus, he said. So is tracking "every spark," he said.

SCE has adopted similar techniques and is pursuing others along the same lines as SDG&E and PG&E.

"They build upon programs we've had for many years — things we've done in response to redline warnings," said Phil Herrington, senior vice president of transmission and distribution for SCE.

About one in 10 wildfires in California are ignited by electrical equipment, but a higher proportion of those fires grow into destructive blazes, state fire officials said.

Elizaveta Malashenko

Elizaveta Malashenko, the CPUC's deputy executive director of safety and enforcement, said the utilities' efforts may be laudable, but their timelines for completion remain uncertain, and no industry-wide standards exist for wildfire prevention. Last year's omnibus wildfire bill, SB 901, required mitigation plans to be filed with the CPUC, yet evaluation has proven difficult without longer-term data, she said.

"The PUC isn't set up to top the expertise of utilities … so I think that's a gap," Malashenko said.

"I think we also lack a vision of where are we going with all of this," she said. "There's a lot of activity that's being proposed as part of wildfire mitigation plans, and it looks like the right type of activity, but we don't really have an articulated vision of what goals we are trying to hit in the future.

"We hear a lot of statements of, 'This is going to take a long time. We shouldn't expect that this first round of wildfire mitigation plans and these efforts that utilities are putting in place right now will address all wildfire problems this year.' … But I think we need to unpack this a bit more and get more specific," she told the committee.

"What does this mean? How long of a roadmap are we talking about? Are we talking about being able to see measurable results in five years, in three years, in 10 years, in 50 years? How are we going to track that, and what does the system of the future look like?"

Regarding wildfire compliance, there are no black-and-white rules like a building code, she said. And the CPUC was never designed to inspect power lines. "That capability is nonexistent," Malashenko said.

Every foot of rail line in the state is regularly inspected by CPUC personnel. Doing the same with power lines would require 1,300 to 1,500 additional workers and an annual budget of $125 million, she told lawmakers.

"To me, the question here isn't which agency does it, but that this gap exists, and we need to recognize it," she said.

(See related story, ***ALJ Endorses CPUC 'Stress Test' for Wildfire Costs***.) ■

## CAISO/WECC News

# ALJ Endorses CPUC 'Stress Test' for Wildfire Costs

*By Hudson Sangree*

The California Public Utilities Commission late Friday released an administrative law judge's proposed ruling approving staff's "stress test" methodology for determining rate recovery for 2017 wildfire costs, part of an effort to maintain the credit ratings of the state's investor-owned utilities.

The methodology, mandated under last year's SB 901, seeks to balance the IOUs' financial health against the impact of rate increases on consumers. (See *California Wildfire Bill Goes to Governor*.)

The *proposed ruling* would not apply to Pacific Gas and Electric, however, because it exempts utilities that have filed for Chapter 11 bankruptcy reorganization. PG&E filed for bankruptcy Jan. 29, citing, in part, its liability for a series of 2017 blazes that tore through Northern California wine country and the Sierra Nevada foothills.

The 2018 Camp Fire, the deadliest and most destructive fire in state history, is not covered under the bill's stress-test provision, though lawmakers may yet apply SB 901's requirements to 2018 fires and future blazes. State investigators recently blamed the Camp Fire on PG&E equipment. (See *Cal Fire Pins Deadly Camp Fire on PG&E*.)

The most obvious application of the proposed ruling would be to Southern California Edison. State investigators determined SCE's power lines sparked the Thomas Fire, a 280,000-acre blaze in Santa Barbara and Ventura counties that killed two people and later caused a mudflow that killed 21. (See *Edison Takes Partial Blame for Wildfire in Earnings Call*.)

The ALJ's decision has no legal effect until the CPUC approves it. The commission may consider the ALJ's proposed order as early as its June 27 meeting.

In the "normal course of regulation of investor-owned utilities, a utility seeks recovery of its anticipated costs of operations and a reasonable return on its investments from ratepayers and seeks equity and debt from public markets to fund those operations in advance of the recovery permitted from ratepayers," Judge Robert W. Haga wrote.

"In the case of a utility exposed to extraordinary costs as a result of a catastrophic 2017 wildfire, however, Senate Bill 901 … adds an exception to the process of rate regulation of investor-owned utilities. Public Utilities Code Section 451.2(b) enacts a new limitation on recovery of such costs from ratepayers and requires the commission to determine the maximum amount, after assessing the financial status of the electrical corporation … that the corporation can pay without harming ratepayers because of an increased cost for access to capital markets, or materially impacting its ability to provide adequate and safe service from inadequate financial resources."

Government investigators said Southern California Edison's equipment sparked the deadly Thomas Fire near Santa Barbara, Calif., in December 2017. | *U.S. Forest Service*

The main driver of the stress test "is the implied maximum additional debt that a utility can take on and maintain a minimum investment grade issuer-level credit rating" based on the ratings of Moody's Corp. and S&P Global, Haga wrote.

Earlier this year, investor services downgraded the credit ratings of PG&E, SCE and Sempra Energy, the parent company of San Diego Gas & Electric, to junk-bond or near-junk status because of wildfire liability worries. California holds utilities strictly liable for fires sparked by their equipment under a state constitutional doctrine known as inverse condemnation. (See *Calif. Must Limit Wildfire Liability, Governor Says*.)

"The stress test therefore focuses on maintaining an investment grade credit rating because this metric is a predictable indicator of a utility's ability to access capital markets on reasonable, acceptable terms, which is critical to avoid materially impacting its ability to provide adequate and safe service. … In addition to materially impacting a utility's ability to provide safe and adequate service, utility ratings below investment grade have negative impacts that harm ratepayers. … The stress-test model therefore looks at the utility's ability to take on additional debt while maintaining an investment grade credit rating, in order to also minimize financial harm to ratepayers," Haga wrote.

The proposed decision wouldn't affect PG&E, he said, because "an electrical corporation that has filed for relief under Chapter 11 of the Bankruptcy Code may not access the stress test to recover costs in an application under Section 451.2(b), because the commission cannot determine the corporation's 'financial status,' which includes, among other considerations, its capital structure, liquidity needs and liabilities, as required by Section 451.2(b), as well as its capacity to take on additional, and all cash or resources that are reasonably available to the utility." ■

# ERCOT News

# ERCOT Technical Advisory Committee Briefs

## *TAC Sends Proposed CONE Revisions to WMS*

AUSTIN, Texas — Unable to reach a decision on a rare update to a key metric used to determine systemwide offer caps, the ERCOT Technical Advisory Committee last week delegated a staff proposal to the Wholesale Market Subcommittee for further discussion.

ERCOT has proposed lowering the peaker net margin (PNM) threshold from $315,000/MW-year to $273,600/MW-year, based on a revised *2018 report* by The Brattle Group that set the cost of new entry (CONE) for generation plants — typically combustion turbines — at $91,200/MW-year. The PNM threshold is set at three times the CONE, which means the $315,000/MW-year threshold used in recent years implies a CONE of $105,000/MW-year.

The PNM threshold is used to determine the point at which the systemwide offer cap is reset from the high offer cap of $9,000/MWh to the low offer cap (the higher number between $2,000/MWh or 50 times the daily effective fuel index price).

During its Wednesday meeting, the committee rejected two separate motions in roll-call votes, both of which would have referred the issue to the WMS for further discussion on the study's values. One motion would have tabled ERCOT's proposal; the second would have approved it. The latter motion fell just short, by a 66-34 margin.

When the smoke cleared, TAC Vice Chair Diana Coleman, of the Texas Office of Public Utility Counsel, agreed with ERCOT to send the proposal to the WMS.

Brattle initially set the CONE for CTs at $88,500/MW-year but revised it in the final draft estimate of ERCOT's market equilibrium and economically optimal reserve margins. The study, which "translated" an *earlier version* conducted for PJM to account for locational cost differences, adjusted assumed interest rates and corporate tax rates to come up with the new CONE.

The current CONE dates back to a 2012 Brattle study, which the Texas Public Utility Commission used to update its resource adequacy requirements earlier this year (Project *48721*). (See "PUC Amends Resource Adequacy Rules," *Texas PUC Briefs: May 9, 2019*.)

The ERCOT Technical Advisory Committee meets May 22. | © *RTO Insider*

"We're in a rising interest rate environment," Reliant Energy Retail Services' Bill Barnes said in advocating for the WMS' further evaluation. "Let's avoid a 10-year backward-looking number and use values that make sense."

ERCOT staff said they would take time to bring in a consultant to review the Brattle analysis. They noted its Independent Market Monitor, Potomac Economics, has used a CONE of between $80,000 to 95,000/MW-year in recent reports and that the process used to change the CONE is "consistent with our current methodology."

Luminant's Ian Haley countered by bringing up FERC's recent approval of PJM's quadrennial revision of its variable resource requirement (VRR) curve used in a pricing model, which has drawn requests for rehearing and protests by both load and supply interests (*ER19-105*). Brattle analyzed the VRR curve's shape and its CONE in recommending several refinements. (See *PJM to Consider Revisions to Demand Curve Design*.)

"This is so controversial in PJM that this is being litigated at FERC," Haley said, objecting to making a "major market change" with seven days' notice. "This is not something PJM instituted and everyone grabbed hands and sang 'Kumbaya.' These are some numbers with big issues in other markets. I have a lot of trouble with [ERCOT] describing them and running with them and showing slight differences [justifying] why they work here in six slides."

### Subcommittees to Review Emergency Procedures

The TAC also delegated to the WMS and its Reliability and Operations Subcommittee further discussions on the need to balance emergency procedures and system reliability.

ERCOT has already spent the last month working to resolve issues raised by a late-winter cold-weather event that resulted in generation resources being forced to adjust their outage schedules. (See *ERCOT Generators Upset over Early March Weather Event*.)

The grid operator has held two workshops on its procedures for issuing operating condition notices (OCNs) and conducted a webinar on a Nodal Protocol revision request (*NPRR930*) that would require it to use a weekly reliability unit commitment process to commit resources

# ERCOT News


Luminant's Ian Haley (right) pushes for more time to consider changes to the CONE. | © *RTO Insider*

with an approved outage. The NPRR also sets an offer floor for the resource at the systemwide offer cap. (See "Changes Coming to ERCOT's OCN Process," *ERCOT Briefs: Week of April 22, 2019*.)

Two other NPRRs (*934* and *935*) addressing emergency procedures are going through the stakeholder process.

TAC members pushed to gain a clearer understanding of ERCOT's OCN procedures and asked for greater accuracy in weather forecasts and planning assumptions.

"The range of possible outcomes of load [and] the range of possible forecasts for wind and icing are all very situationally dependent," ERCOT COO Cheryl Mele said. "I'm not sure that is something we can hard code. We want to make that as transparent as possible and share that information with folks as soon as we can. I don't think we can develop specific criteria around that because cold weather, hot weather [and] wet weather combined with cold all present very different types of risks to us."

"We don't expect hard coding, but we think we can get close to it," Calpine's Brandon Whittle said. "I think there's a way to narrow that scope a little bit to where we have general consistency."

"We don't want an emergency declared days in advance, which is not what ERCOT wants to do," Citigroup Energy's Eric Goff said. "There are certainly other instances in the protocols worth finding and revising. At the same time, we can ensure we have communications around emergency conditions that are very clear and procedures that don't have much guesswork."

Barnes said his concern is that market participants are using ERCOT's planning assumptions and the planning process to make operational decisions, "so we're always going to overshoot."

"That's the nature of solving this problem," he said. "Inherent in our market design is an acknowledgement we're willing to accept a high level of reliability risk."

Barnes referred to *recent comments* filed by *Texas Competitive Power Advocates*, a trade association representing ERCOT generators, wholesalers and retail providers. TCPA called for a holistic review of ERCOT's reliability standards by the grid operator itself, along with Texas Reliability Entity and market participants.

"[TCPA] is concerned that this fundamental conflict between the reliability standards and required scarcity means that even lower reserve margins will be required before the economic signals are apparent and trusted to lead to a turnaround in supply," the association said.

"There's a lot of subjectivity in interpreting the standards," Barnes said. "Not just ERCOT, but every power market has this tension between the need to preserve reliability and the need to let markets solve those problems. I know we probably have a reluctant partner in ERCOT to review the standards to see if there's more room for relaxation of those, but that's worth continuing to discuss."

## Wind, Solar Energy Set New Marks in April

Mele's revamped operations report revealed ERCOT in April set new monthly generation records for its wind and solar fleets, producing 7,148 GWh and 408 GWh, respectively. That bettered the previous marks of 7,060 GWh of wind in May 2018 and 368 GWh of solar last June.

Wind energy accounted for 26.7% of ERCOT's production during April, besting coal (19%) and nuclear (12.3%), while gas accounted for 39.9%.

April's peak demand of 51.6 GW was a 3.7% increase over April 2018's peak (47.9 GW) but below the April 2017 record of 53.5 GW.

Mele said she wants to retire the previous operations report's format but agreed to add real-time revenue neutrality allocation (RENA) metrics to the deck. RENA measures the amount of leftover market revenue paid to qualified scheduling entities on a load-ratio share to keep the grid operator revenue neutral.

## TAC Tables One Change, but OKs 17 Others

Committee members tabled an NPPR (*917*) that would set a 20-year grandfathering period to assist settlement-only distribution and transmission generators (SODGs and SOTGs) in their transition from zonal to nodal energy pricing.

NPRR917 currently allows existing SODGs and SOTGs to apply for continued zonal pricing until they opt in for nodal pricing or Jan. 1, 2030, whichever comes first. The proposed rule would grandfather distributed generation resources that have entered into interconnection agreements or power purchase agreements before Jan. 1, 2019.

In objecting to the request, solar developer Cypress Creek Renewables called for allowing existing SODGs and SOTGs to opt out of nodal pricing and continue to receive zonal prices for five years, with the option of extending the treatment for additional five-year increments for up to 40 years.

Cypress Creek is supported by Lower Colorado River Authority, which prefers a longer grandfathering period rather than a shorter one. The two entities will work together over the next month on joint comments.

Ralph Daigneault, legal counsel for Potomac Economics, said the Monitor is concerned with any grandfathering clause, but even more so when the term extends to 40 years.

"We think it's bad precedent and bad market design. Any exception to that perpetuates the bad market design," he said. "I think the comments by Cypress Creek are a step backwards. The smaller we get with that number, the more comfortable the IMM is going to be."

"The big motivation for doing this zonally is if

# ERCOT News

you have a load entity in that zone, and your generation is in that zone, you get a natural hedge," said Walter Reid of the Advanced Power Alliance. "That is the business model that was expected, but unfortunately, we're changing that."

ERCOT says the change would better align its operations with the overall nodal market design and reliability needs and would increase economic efficiency.

The TAC did approve seven other NPRRs, three revisions to the Nodal Operating Guide (NOGRRs), four other binding document changes (OBDRRs), two modifications to the Planning Guide (PGRRs) and a system change request (SCR):

- *NPRR885*: Adds new language to address the solicitation and operation of must-run alternatives, as directed by the Texas PUC (Project *46369*). The commission ruled that a resource entity must file a notification of suspension of operations at least 150 days prior to the date on which it intends to cease or suspend operations; within the 150-day notice period, ERCOT must determine whether the resource is needed for reliability.
- *NPRR896*: Outlines the process to evaluate the cost-effectiveness of procuring reliability-must-run service or one or more must-run alternatives.
- *NPRR921*: Replaces all instances of the "all-inclusive generation resource" and "all-inclusive resource" terms with "generation resource and settlement-only generator (SOG)" and "generation resource, settlement-only generator and load resource," respectively. Eliminating the all-inclusive generation resource enables ERCOT to more narrowly tailor the requirement's applicability to a reasonable scope.
- *NPRR923*: Updates the weather-sensitivity process by allowing transmission and/or distribution service providers an additional 30 days to complete the investigation and execution of requests to revise electric service identifier (ESI ID) load profiles.
- *NPRR924*: Moves the Independent Market Information System Registered Entity Application for Registration form into a section of the Nodal Protocols that houses similar forms.
- *NPRR926*: Removes the 90-day period between subsynchronous resonance (SSR) study approval and initial synchronization, clarifies that the SSR mitigation plan is part of the SSR study, and adds an ERCOT review process that gives the grid operator 30 days to review the SSR study. The change also gives ERCOT 45 days to implement any required SSR monitoring after the study's approval.
- *NPRR929*: Adds new criteria for determining whether a point-to-point (PTP) obligation with links to an option bid is eligible to be awarded based on the resource's current operating plan (COP) status at the node where the bid sources. Bids will not be eligible for awards if they source at a resource with a COP status of "OUT" or "OFF" and the resource is not offered into the day-ahead market.
- *NOGRR185*: Uses the terms created in *NPRR889* (RTF-1 Replace Non-Modeled Generator with Settlement Only Generator) to replace the terms "all-inclusive generation resource" and "all-inclusive resource" in the Nodal Operating Guide.
- *NOGRR188*: Aligns the guide's language with ERCOT's wide area network refresh project to allow implementation of Voice over Internet Protocol.
- *NOGRR189*: Aligns the NOGs with NERC Reliability Standard *PRC-002-2* (Disturbance Monitoring and Reporting Requirements).
- *OBDRR009*: Revises the online and offline capacity reserves to prevent price reversal and price distortion during DC tie out-of-market actions.
- *OBDRR013*: Changes the current single-value voltage categories of 345, 138 and 69 kV used to define generic transmission shadow price caps for N-1 constraint violations to accommodate Lubbock Power & Light's transmission equipment, which does not fall into the three existing categories. The ranges are: greater than 200 kV ($4,500/MW), 100 to 200 kV ($3,500/MW) and less than 100 kV ($2,800/MW).
- *OBDRR014*: Changes the location where resource nodes with disallowed energy-only offers, energy bids and point-to-point bids will be posted, and clarifies that the congestion revenue rights team will use the most recent list when building the auction model. The OBDRR also modifies its approval process to better account for revisions that may require a project and a separate SCR.
- *OBDRR015*: Sets the value of lost load (VOLL) equal to the systemwide offer cap, which changes the high systemwide offer cap to the low systemwide offer cap should the PNM exceed its threshold within an annual resource adequacy cycle.
- *PGRR069*: Uses terms created by *NPRR889* to replace the terms "all-inclusive generation resource" and "all-inclusive resource" in the Planning Guide. The PGRR also clarifies the applicability of the generation interconnection or change request process to different generators, based on NPRR889.
- *PGRR070*: Aligns the Planning Guide with NERC Reliability Standard *TPL-007-2* (Transmission System Planned Performance for Geomagnetic Disturbance Events) by identifying responsibilities for performing studies needed to complete benchmark and supplemental geomagnetic disturbance vulnerability assessments.
- *SCR799*: Enables ERCOT to provide transmission service providers its current month, 60-day and 90-day outage study cases in the system operations test environment on a monthly basis. ■

*— Tom Kleckner*

TAC Vice Chair Diana Coleman (left) and ERCOT COO Cheryl Mele listen to the discussion. | © *RTO Insider*

# Texas PUC Briefs

### Commission Delays Action on Oncor-AEP Texas Project

Texas regulators last week delayed action on a proposed transmission project in the oil-rich Permian Basin, allowing the parties involved to make modifications in the *proposed order* (Docket *48785*).


The Texas PUC's May 23 open meeting

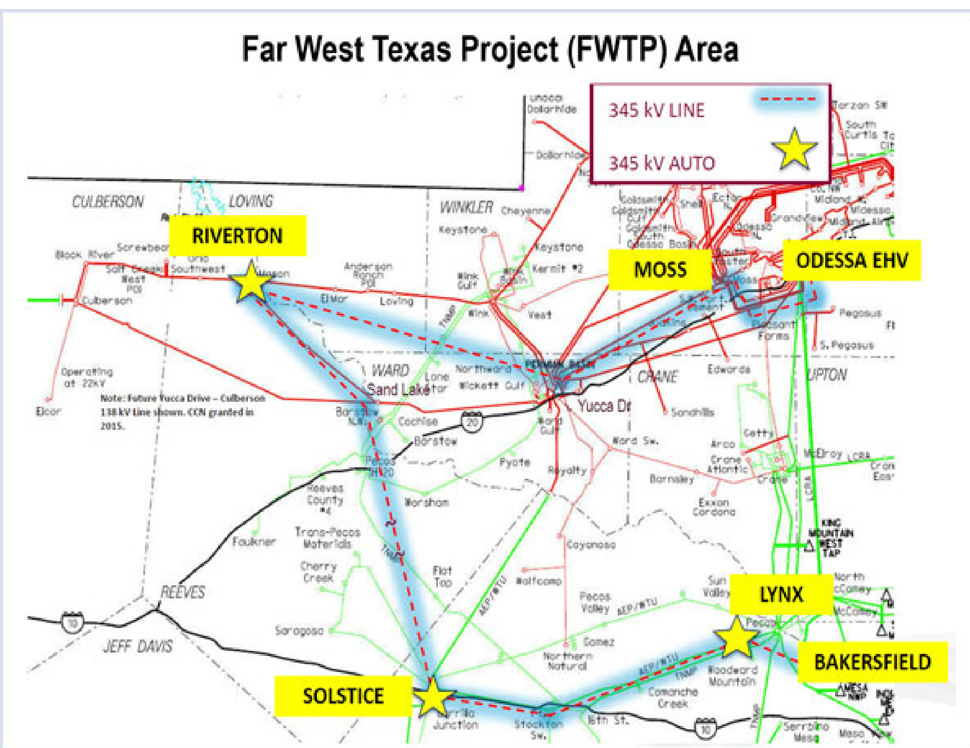
"Two weeks won't hurt us," PUC Chair DeAnn Walker said during Thursday's open meeting. The commission meets next on June 13.

Oncor and AEP Texas filed an application last year to build a 345-kV double-circuit transmission line from Oncor's Sand Lake switch station in Ward County to AEP Texas' Solstice switch station in Pecos County. The potential routes range from 44 to 59 miles in length with estimated costs of $98 million to $127 million. The line is part of the $336 million Far West Texas transmission project, approved by ERCOT in 2017. (See *ERCOT Board Approves West Texas Transmission Project*.)

The Route 320 path recommended by Administrative Law Judge Steven Neinast runs through what the judge called a "densely packed" Occidental Petroleum oilfield. Occidental would like to see the line shifted at a cost of $18 million.

Walker added language to the order to give Oncor and AEP flexibility in deviating from the approved route, but only if the parties can receive consent from all affected landowners. Oncor and Occidental both said they were having trouble working with all the landowners.

"I understand the problems they're talking about," said Walker, a former landman. "I don't mind giving utilities some leeway to relocate, but I don't know that we can get as far without the consent of landowners. I was prepared to move [this] out, because we've got to get transmission in the Permian Basin, but I think $18 million is a large amount to add to the transmission cost."




| *ERCOT*

### AEP, LCRA Get Their West Texas CCNs

The PUC *awarded* certificates of convenience and necessity (CCNs) to AEP and Lower Colorado River Authority Transmission Services for the Bakersfield-Solstice portion of the Far West Texas transmission project (Docket *48787*).

The project will connect AEP's Solstice station and LCRA's Bakersfield station with a 71-mile, 345-kV double-circuit line. The preferred route was the fourth cheapest among 25 options at $156 million. Expansion work at the two substations will add $45 million to the project.

AEP and LCRA said the project will support the area's load growth, address reliability violations and provide the infrastructure necessary to facilitate further expansions. The companies cited an eight-fold load increase on nearby transmission lines that were built in 2012 and 2017.

### PUC Grants SWEPCO $6.5M Recovery

In other actions, the PUC *granted* Southwestern Electric Power Co.'s request to recover nearly $6.5 million through its distribution cost recovery factor (Docket *49041*).

The commission also approved a pair of settlements that resulted in $210,000 in administrative penalties:

- Retail electric provider Ambit Energy was assessed $160,000 for moving numerous customers to a new, higher-priced plan without the customers' consent (Docket *48859*).
- LCRA was hit with a $50,000 penalty for failing to reserve sufficient capacity to meet its response reserve service obligations (Docket *49466*). ■

*— Tom Kleckner*

## ISO-NE News

# FERC Sets Conference on New England Fuel Security

*By Rich Heidorn Jr.*

FERC has agreed to New England's request for a public "prefiling" meeting to discuss the region's plans for long-term fuel security.

The staff-led session at FERC's headquarters in D.C. on July 15 will include three, 90-minute presentations by ISO-NE, New England Power Pool stakeholders and state officials followed by questions from commissioners and staff (*EL18-182, ER18-2364*, et. al.).

ISO-NE, NEPOOL and the New England States Committee on Electricity (NESCOE) jointly *requested* the meeting in April, saying ex parte rules had prevented them from discussing with the commission their efforts to develop a long-term, market-based energy security plan, as the commission ordered last July. ISO-NE's proposed Tariff revisions are due Oct. 15. (See *FERC Denies ISO-NE Mystic Waiver, Orders Tariff Changes*.)

"The solutions and alternatives under consideration are complex," the request said. "It would be particularly helpful if the region can preview its proposals and issues with commission staff, both to assist the commission's understanding of the issues and to receive any preliminary feedback and direction."

The commission's July 2 show-cause order instituted a Federal Power Act Section 206 proceeding after finding that ISO-NE's Tariff is not just and reasonable because the RTO lacks a way to address fuel security concerns that it said could result in reliability violations as soon as 2022.

Distrigas Terminal at sunset | *Everett Chamber of Commerce*

ISO-NE last month issued a *white paper* on the challenges the region faces because of its increasing reliance on natural gas-fired generation — which may be unable to obtain fuel in the winter — and intermittent renewables. The paper said ISO-NE's efforts to encourage gas-fired generators to invest in dual-fuel capability or LNG storage had proven inadequate because of "misaligned incentives."

"Making these discrete investments, if they meaningfully reduce the risk of electricity supply shortages (and therefore the risk of high prices), entails up-front costs to the generator — yet reduce the energy market price the generator receives," the RTO explained.

As a result, the RTO is proposing:

- Expanding the one-day-ahead market into a multiday-ahead market that optimizes energy (including stored fuel) over several days.
- Creating new ancillary services in the day-ahead market to compensate generators for providing the flexibility of energy "on demand" to manage uncertainties during the operating day.
- Creating a seasonal forward market to provide resources with incentives to invest in supplemental fuel supplies for the winter.

The paper said the RTO is "in the early, conceptual stages of evaluating designs" for the forward market and that its "immediate focus is to first work with regional stakeholders to develop the … multiday-ahead markets and their integrated new ancillary services."

RTO officials *discussed* the multiday-ahead proposal with stakeholders at NEPOOL's Markets Committee meeting May 7. ■

# 'Grid Transformation Day' Highlights ISO-NE Challenges

Continued from page 1

as of April 1 is already out of date, with the number now topping 2,500 MW.

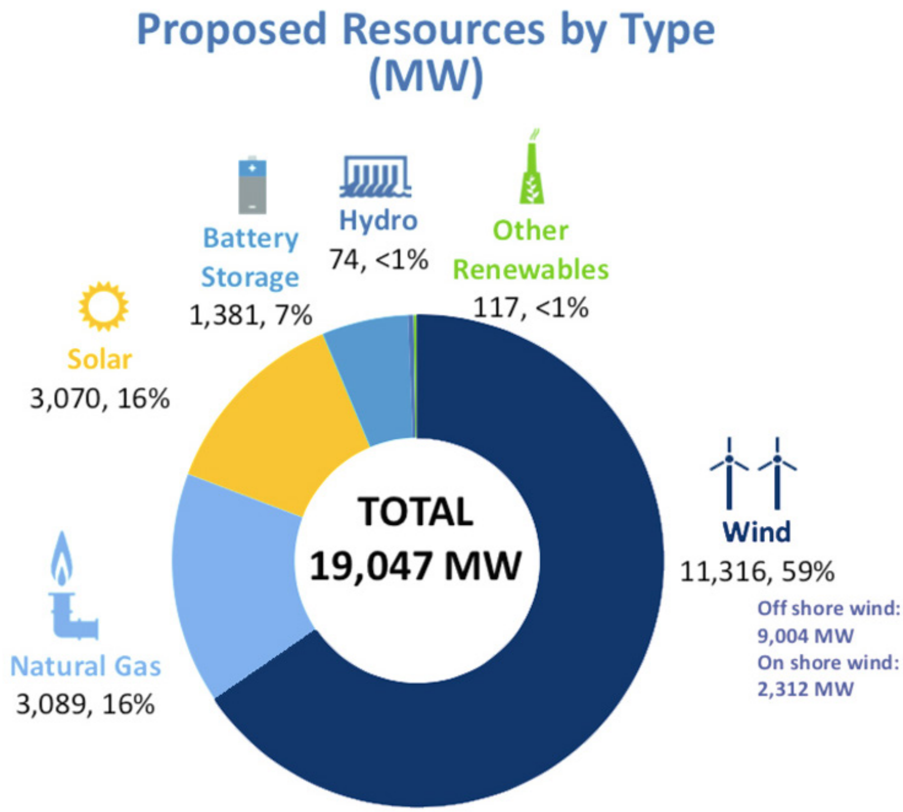
Information is still key, he said about the RTO's response to growth of distributed energy resources.

"So every night at around 10 or 10:30, we get five-minute snapshot data from 10,000 different solar sites around the region," Rourke said. "Thanks to working with the utilities and the states, we have actually mapped every single solar panel in New England to the town or city that it's in."

However, getting that data in real time would significantly increase costs, "so we have not gone down that path yet," he said.

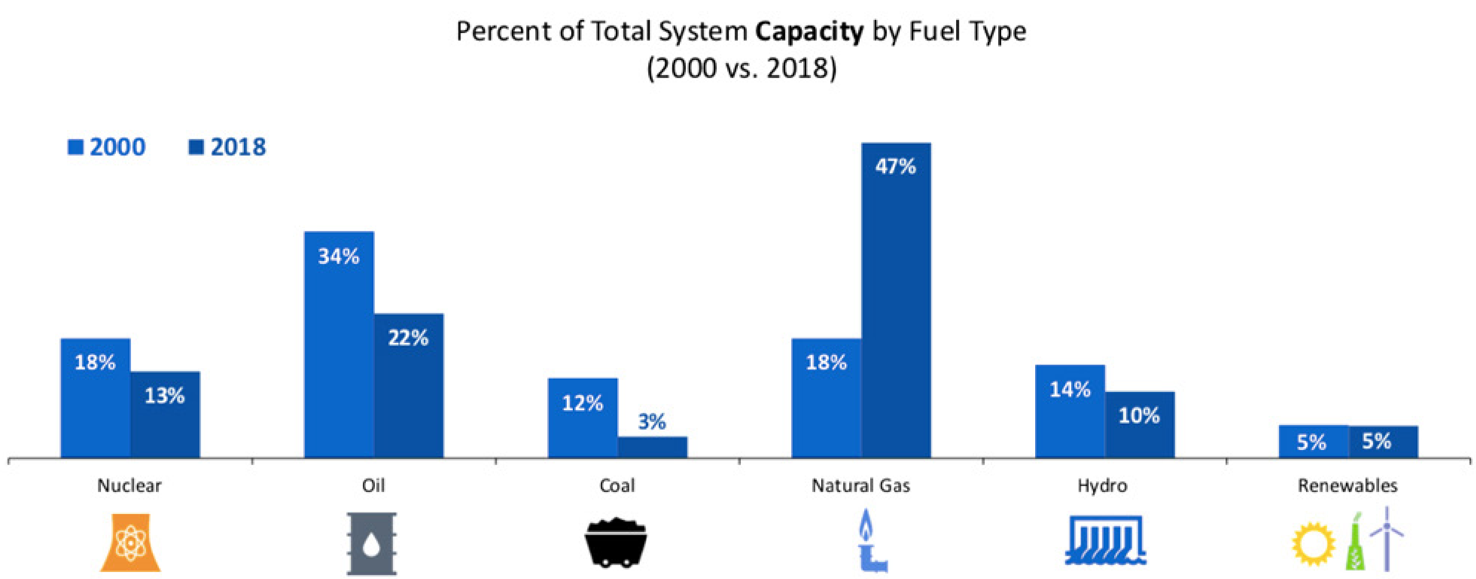
Steve Widergren, principal engineer at Pacific Northwest National Laboratory, said that our modern, data-driven society requires a much more flexible and resilient transmission system, which must transition to meet the challenges of changing demand characteristics, he said.

"We're asking the grid to do a lot more than it was originally designed to do, which I think has been the mantra for electricity through its entire life," he said. "We have already seen what extreme weather events are doing and can do, so the mission is how to mitigate the damage and recover quickly. The grid is increasingly a critical national asset."




| ISO-NE

The policy environment is changing as "corporates and municipalities are demanding more clean energy, and this clean energy operates in a different way from traditional power plants, so that's a challenge for the system," said Janet Gail Besser, managing director of regulatory innovation at the Smart Electric Power Alliance.




Renewables are only 5% of New England's installed generating capacity today, but wind and solar are on the rise. | *ISO-NE*

# ISO-NE News

She listed various legislative initiatives around the region, including a bill on solar siting in Rhode Island (*House Bill 5789*).

"As we see more of these resources, we see more of the challenges in siting even distributed energy resources, and that's not going to go away," Besser said.

## Technical Challenges

Aidan Tuohy, principal project manager at the Electric Power Research Institute (EPRI), spoke of the challenges of integrating DER into grid operations, such as ramping to compensate for both short- and long-term intermittency of wind and solar.

In his native Ireland, for example, the grid operator is "buying 14 different kinds of ancillary services to deal with all this," Tuohy said.

Hosting capacity — the volume of DERs that the distribution system can handle at a given time and place — is important from a bulk services perspective and comes up when trying to get distributed battery storage to provide some service that can't actually be accessed because the system is starting to hit some limit, Tuohy said.

"EPRI has been exploring the use of technologies to better understand where and how much DERs you can put on your system so that you can then plan around that ... and flag where upgrades are needed," he said.

Barry Mather, manager for integrated devices and systems at the National Renewable Energy Laboratory, said grid operators have "a lot of tools in the toolbox" and that the large number of options is in itself a challenge.

In sharing NREL research on the Hawaii grid, Mather said it is "a very interesting system with lots of PV; mostly distributed, not transmission-scale," which results in steady-state over-voltage issues.

What smart inverter function should actually be used?

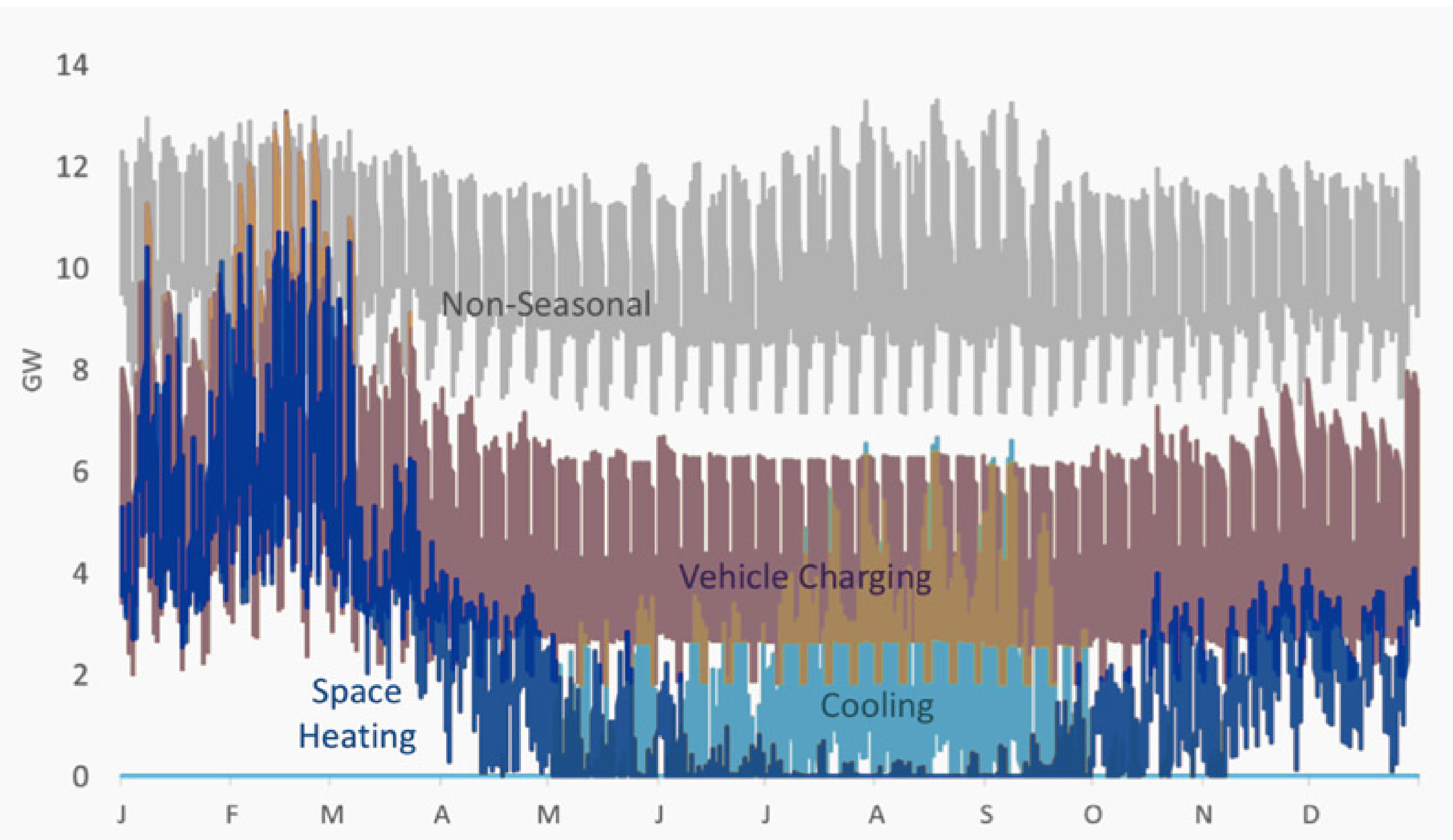
"Obviously, frequency ride-through is a big deal on an island system such as in Maui, where you have relatively large frequency transience, just because the system is not very large," Mather said. "But even [with] things like the volt/[volt-ampere reactive] settings [on inverters], how specific do you need to be?"

"Another important step in this planning matrix is to understand where you are going to go, because these DER assets, even though they're small systems ... are designed relative to a utility-scale lifetime, maybe 25 or 30 years," Mather said.

The smart inverter setting you set today may not be the same setting that will be needed when DERs reach their ultimate penetration level, he said.

"The biggest game-changer is demand response," said Debra Lew, senior technical director at GE Energy Consulting. "I can't convey to you the importance of this ... think of it as demand response on steroids. This is going to be way bigger than what you think of today because, first of all, we're electrifying all these new loads," from transportation to space heating to water heating and cooling.

"These loads are inherently flexible; we can extract a lot of flexibility out of them, so a significant amount of our demand in the future is going to be price-responsive or controllable," Lew said. "This demand is going to compete directly with storage, and that's something to think about as you make investments for the future."




Potential New England 2050 load profiles by end use | *EPRI*

# ISO-NE News

Lew said she participated in a meeting the previous week in which a Californian said their state currently had a half-million electric vehicles and plans for 7 million.

"We did a back-of-the-envelope for 7 million electric vehicles: 420 GWh of storage. That's huge," Lew said. "Even if you can access only a tiny bit of that, that's a huge amount of storage."

### Utility Perspective

"Vermont is the Hawaii of the East, but our mountains don't blow off their tops," said Chris Root, COO of Vermont Electric Co.

Vermont is leading the way in New England in terms of overall renewable energy on its system, but because of the intermittent nature of wind and solar, its grid is increasingly weather-dependent as more renewables come on, Root said.

For example, he said the load in the middle of an overcast day is 2.5 times that of a sunny day, and that when snow covers a solar panel, its energy production drops to zero — which drew the comment that Hawaii probably had the edge in weather.

"I do believe storage is going to be critical in the future, because we have loads that change, we have generation that changes, and the only thing that's going to be able to equate that is going to have to be storage," Root said.

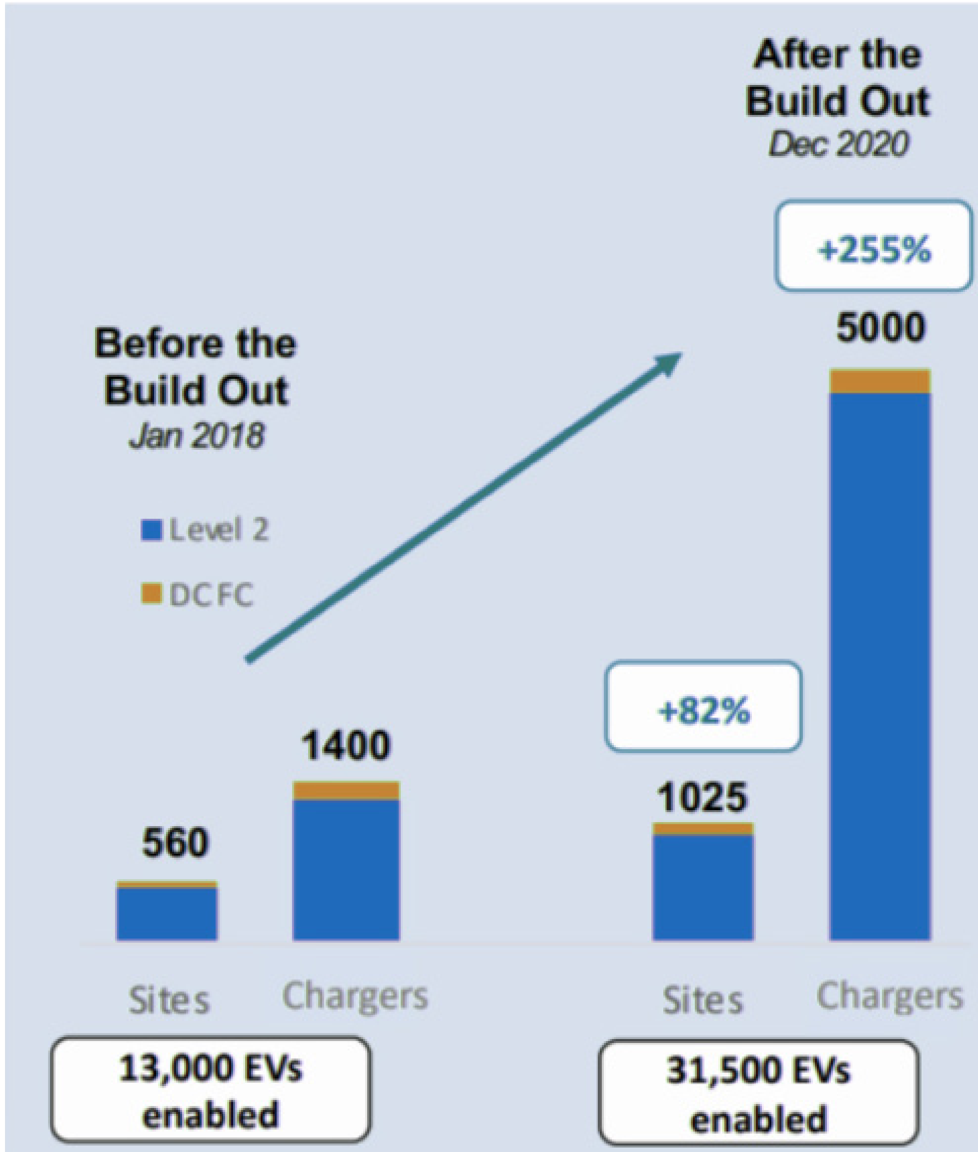
He said Vermont utility Green Mountain Power has installed 1,900 Tesla Power Walls and "can't install them fast enough." He noted the state has two utility-scale energy storage facilities of 4 MW and 1 MW — but he likes to remind people that storage is not an energy source.

"You have to put energy in; then you can take it out.

"Sometimes when policy gets way ahead of engineering, that can be a little scary," Root said. "We're still solving the problems that are happening today, so it gets a little scary when you're trying to play catch-up from an engineering perspective."

National Grid has seen its average solar interconnection request in Massachusetts triple in size over the last few years and double in Rhode Island, said Brian Gemmell, the company's vice president for asset management and planning.

"For those that know the transmission system well, there's a lot of ripple effect with getting all these megawatts. ... We don't have a lot of transmission in central and western Massachusetts and, indeed, some of the areas in Rhode Island," Gemmell said. "We're grappling with a dramatic uptick in [distributed generation]."




Massachusetts has approved $45 million to support the sale of approximately 18,500 EVs over five years. | *Eversource*

"It's a given that we're going to need innovation ... but the biggest thing we'll need is collaboration," said Vandan Divatia, Eversource Energy's director of ISO-NE policy and interconnections. "We have a role in every sector of the grid, from a customer-facing angle to grid-type investments, to supply, and the key thing is going to be collaborating with the right folks."

Highlighting the ambitious clean energy policies and greenhouse gas reduction targets of various states in the region, Divatia said, "This may mean, based on the numbers you run ... one scenario is you need to have every single new vehicle by 2030 to be electric.

"Massachusetts has shown great leadership in this area by enabling a make-ready program to deploy $45 million to get about 18,500 EVs," and the region needs about 80,000 charging stations to help people overcome their range anxieties regarding EVs, Divatia said.

"Again, if we want to go from here to there, we're going to need a lot more electric infrastructure," he said. ■

*— Michael Kuser*

ISO-NE News

# ISO-NE Planning Advisory Committee Briefs

## 2019 Economic Study Includes All Requests

WESTBOROUGH, Mass. — ISO-NE told the Planning Advisory Committee on May 21 that it plans to conduct all three economic studies requested by stakeholders last month.

Marianne Perben, ISO-NE manager of technical studies and resource adequacy, *presented* the 2019 Economic Study Draft Scope of Work and High Level Assumptions to the PAC. (See "Economic Study Requests Focus on Wind," *ISO-NE Planning Advisory Committee Briefs: April 25, 2019*.)

The studies will cover:

- A New England States Committee on Electricity (NESCOE) request to analyze various scenarios for integrating offshore wind by 2030, focusing on the impact on the transmission system and wholesale market. The study will examine a range of 2,000 to 8,000 MW of OSW resources, Perben said.
- A request by transmission developer Anbaric Development Partners to review the impacts of OSW on energy market prices, emissions and regional fuel security in 2030. The study will look at an 8,000- to 12,000-MW range of OSW.
- A RENEW Northeast request to evaluate transmission upgrades that would increase the hourly operating limits of the Orrington South interface in Maine.

The three studies will rely on a number of common assumptions, including: modeling Forward Capacity Market and energy-only generators at their seasonal claimed capability; using the most recent U.S. Energy Information Administration forecasts for New England coal, oil and natural gas prices; and reflecting $CO_2$, $SO_2$ and $NO_x$ prices in fossil fuel generation. Michael Henderson, the RTO's director of regional planning and coordination, cautioned participants that "these are economic studies, not detailed transmission studies."

In response to a question about why the RENEW study would exclude the western Maine cluster of resources in the interconnection queue, Perben said the cluster was not part of the request.

Asked about varying threshold prices in the analysis, Perben said ISO-NE uses them to facilitate analysis of load levels where the amount of $0/MWh resources exceeds the system load. They "are really just a way to know when to curtail those resources," she said.

| Price-Taking Resource | Threshold Price ($/MWh) |
|---|---|
| Behind-the-Meter PV | 1 |
| NECEC (1090 MW) | 2 |
| Utility Scale PV | 3 |
| Onshore/Offshore Wind | 4 |
| New England Hydro | 4.5 |
| Imports from QC (Highgate & Ph. II) | 5 |
| Imports from NB | 10 |

The RTO uses these threshold prices to facilitate analysis of load levels where the amount of $0/MWh resources exceeds the system load. | *ISO-NE*

## New Hampshire 2029 Needs Assessment Outlined

Jinlin Zhang, the RTO's lead engineer for transmission planning, gave the committee a *briefing* on the New Hampshire 2029 Needs Assessment.

In February, ISO-NE suspended its New Hampshire 2027 Solutions Study process in order to incorporate changes in the draft 2019 Capacity, Energy, Loads and Transmission (CELT) forecast data, which showed the regional net load figure the RTO was using was too high.

The RTO used the draft 2019 forecasts to update the models to reflect the change in load, energy efficiency and solar PV volumes from the 2018 CELT, Zhang said.

She highlighted the "very important date" of June 10 as the deadline to notify the RTO of any resources it should consider including in the Needs Assessments.

Resources to be included are those that have cleared a Forward Capacity Auction, have signed contracts from state-sponsored requests for proposals, or are otherwise obligated by contract.

Two projects that received capacity supply obligations (CSOs) in FCA 13 have been added to the 2029 cases, she said. A 632-MW combined cycle plant in Connecticut is far from the study area and therefore modeled offline, while a 123-MW solar farm connecting into the Albion Road 115-kV substation in Maine is modeled

| Category | NH 2027 Needs Assessment | NH 2029 Needs Assessment |
|---|---|---|
| CELT | 2018 | Draft 2019 |
| RSP Project List and Asset Condition List | As of June 2017 | As of March 2019[1] |
| Local System Plan (LSP) Projects | 2017 TOPAC | 2018 TOPAC[2] |
| Transmission Planning Base Case Library Used | 2017 | 2017 |
| Cleared Generator Additions | Through FCA 11 | Through FCA 13[3] |
| Submitted Retirement Delist Bids | Through FCA 12 | Through FCA 14 |
| Short Circuit Base Case Used | 2022 | 2023 |

New Hampshire Needs Assessment changes | *ISO-NE*

# ISO-NE News

at about 32 MW, or 26% of nameplate.

In addition, four generators have been set as out-of-service in the 2029 cases, with one generator in New Hampshire (Schiller 4 at about 48 MW) fully delisted for the second consecutive FCA, which is the cutoff for considering the resource unavailable for dispatch when performing a Needs Assessment. If a resource does not operate for three calendar years in a row, it is deemed to be retired.

The New Hampshire 2029 Needs Assessment will consider sensitivity study scenarios of the unavailability of all major generators in Central New Hampshire, as well as the addition of the 1,090-MW New England Clean Energy Connect (NECEC) *project* that would deliver Canadian hydropower and wind energy to the Larrabee Road 115-kV substation in Maine. NECEC was proposed in response to a solicitation by Massachusetts utilities.

Although NECEC does not yet have an approved contract from Massachusetts regulators, ISO-NE recognizes the project may be approved prior to or soon after the completion of the Needs Assessment, Zhang said.

In addition, the RTO will examine the unavailability of one Comerford and one Moore hydro generator.

The study models photovoltaic generation based on the draft 2019 CELT forecast.

"And when we studied generation unavailable, we studied generation unavailable in the neighboring area," Zhang said. "All interface transfers are within their limits, demonstrating that the established reserves are acceptable."

The RTO plans to post the updated 2029 Needs Assessment intermediate study files in Q3 2019. The assessment is expected to be completed by Q3 or Q4 2019, she said.

## Emergency Actions Eyed to Address Potential Shortfall in Operable Capacity

ISO-NE projects the region's net installed capacity requirements (ICRs) will increase by 480 MW by 2028 and that operating procedures could be needed to overcome a shortage of "operable" capacity.

Those were some of the highlights of a *presentation* the RTO gave the PAC on resource adequacy studies to be included in the 2019 Regional System Plan.

Peter Wong, the RTO's manager of studies and assessment, said net ICR — 33,390 MW this year — is projected to increase to 33,870 MW by 2028.

Wong said the 34,839 MW of "known resources," based on CSOs from FCA 13, are sufficient to meet the net ICR values through the 2028/29 capacity commitment period.

A comparison of the representative net ICRs with the FCA 13 resources plus the energy efficiency forecast shows a surplus of 2,291 MW in 2029, assuming no resource retirements, he said.

However, the RTO's analysis of "operable" capacity — which deducts unplanned generator outages and gas-fired generation that may not be able to obtain fuel during peak winter periods — indicates the region may have to rely on load or capacity relief measures under Operating Procedure 4 (*OP-4*) to avoid shortfalls.

The analysis deducted 2,100 MW from the summer capacity based on historical unplanned outages, and 8,600 MW in winter based on the highest planned and unplanned generator outages during 2014-2018 and the highest amount of gas-fired generation at risk during the three-week winter peak.

Under 90/10 peak load conditions, the region could have operable capacity shortfalls of -1,150 to -2,500 MW during the summer and -1,370 to -2,500 MW during the winter.

Assuming 50/50 peak load conditions, New England could fall short of operable capacity during the winter peak for the entire study period and during the summer starting with delivery year 2024/25. Operable capacity shortfalls range from -310 to -470 MW during the summer and -160 to -1,200 MW during the winter.

The RTO said OP-4 actions of up to Action 6 (a 5% voltage reduction) could be needed to meet 50/50 loads and up to Action 9 (requests of all generation not contractually available to market participants and voluntary load curtailments by large industrial and commercial customers) to serve 90/10 loads.

Other operating procedures anticipated include depleting 10- and 30-minute operating reserves and importing power from other regions.

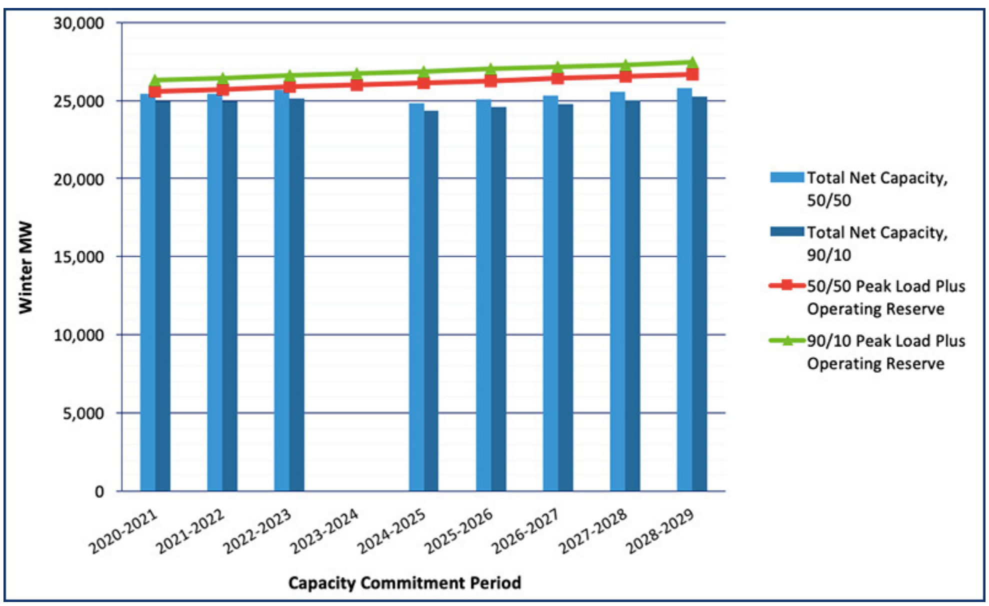
Wong said the RTO is anticipating a possible change in what has historically been a summer-peaking region.

"We are reviewing the growth in demand-side resources and the penetration of PV both behind the meter and in front of the meter, and the penetration of heat pumps," Wong said. "Penetration of PV is not only shifting the time of the daily peak; it is possible that the system will shift to dual-peaking and then to a winter-peaking system."

The Power Supply Planning Committee will conduct a final review of all assumptions on June 20 and July 25 and will review ISO-NE recommendation of ICR values Aug. 9 and Aug. 29 ahead of a Reliability Committee review and vote on ICR values on Aug. 20 and Sept. 25.

The Participants Committee will review and vote on the recommended ICR values Oct. 4, which will be filed with FERC by Nov. 5. ■

*— Michael Kuser*




2019 CELT winter forecasts | *ISO-NE*

## ISO-NE News

# ISO-NE on Track with GMD Standard

*By Rich Heidorn Jr.*

ISO-NE has completed its work on the first two requirements to take effect under NERC's revised geomagnetic disturbance (GMD) standard and will be fully compliant by the end of the year with requirements effective in July 2020, the RTO told the New England Power Pool's Reliability Committee on Wednesday.

*TPL-007-3* (Transmission System Planned Performance for Geomagnetic Disturbance Events) replaces TPL-007-1, effective July 1. TPL-007-3 added a regional variance for Canadian jurisdictions to TPL-007-2, which FERC approved in Order 851 in November (*RM18-8, RM15-11-003*). (See *Revised NERC GMD Standard Approved*.)

NERC developed the new standard in response to FERC's directives to improve how its initial GMD rules, approved in 2016, addressed the risks from "locally enhanced" events. It broadens the definition of GMDs, requires grid operators to collect certain data and imposes deadlines for corrective actions.

The standard applies to planning coordinators (PCs), transmission planners (TPs) and transmission owners (TOs)/generator owners (GOs) with power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

NERC's original standard required applicable entities to assess the vulnerability of their transmission systems to a "benchmark" GMD event — defined as a one-in-100-year event. The new standard addresses FERC's directive to revise the benchmark GMD event definition so that it is not based solely on the averaging of magnetometer readings over a geographic area. NERC defined the "supplemental" GMD event using individual station measurements rather than spatially averaged measurements, acknowledging that geomagnetic fields during severe GMD events can be "spatially non-uniform" with localized peaks that could affect reliability.

### 5 New Requirements

The standard adds five new requirements. R8, R9 and R10 require responsible entities to assess the potential implications of the supplemental GMD event on their equipment and systems. R8 requires the completion of a supplemental GMD vulnerability assessment at least once every five years. If the analysis finds the supplemental GMD event would cause cascading outages, the responsible entity must evaluate ways to reduce the likelihood or mitigate the impact of the event. NERC said its standard drafting team concluded that an evaluation was more appropriate than a formal corrective action plan "in light of the limitations of currently available tools for modeling localized GMD effects."

R9 requires responsible entities to provide geomagnetically induced current (GIC) flow information based on the supplemental GMD event to owners of applicable bulk electric system power transformers in the planning area. R10 requires TOs and GOs to conduct a supplemental thermal impact assessment for BES power transformers where the maximum effective GIC value resulting from R9 is above a threshold (85 A per phase or greater).

Under R11 and R12, PCs and TPs must obtain GIC monitors and geomagnetic field data for their planning areas or system model areas. They must have at least one GIC monitor in their regions.

The new standard also made conforming changes to other requirements and revised the deadlines in R7 for corrective action plans required to address system performance issues identified in the benchmark vulnerability assessment.

ISO-NE's Alex Rost said the RTO is already compliant with R1, which concerns the definition of PCs' and TPs' roles and responsibilities, and R2, maintaining system GIC models.

He said the RTO will be compliant by Dec. 1 with R5 ("Provide benchmark GIC flow information to applicable TOs and lead market participants [MPs] for applicable GOs") and R9 ("Provide supplemental GIC flow information to applicable TOs and lead MPs for applicable GOs"), which take effect in January.

Rost said the analyses required by the standard can be "iterative" — results obtained in later stages of the study cycle may prompt the rerun of early-stage work.

He said most of the GIC modeling data required is already included in the New England system GIC model but that the RTO will notify applicable entities if modeling updates are needed. ■

| TPL-007-3 Requirement | Responsible Entities | Compliance Deadlines | Implementation Plan Due Date |
|---|---|---|---|
| [R1] – Define Roles and Responsibilities | ISO/TPs | 7/1/2019 | Compliance requirement met |
| [R2] – Maintain System GIC Models | ISO, App. TOs/App. Lead Market Participants for GOs | 7/1/2019 | Ongoing effort, compliance requirement met |
| [R3] – Specify Steady State Voltage Performance Criteria for GMD Vulnerability Assessment | ISO/TPs | 1/1/2023 | 1/1/2022 |
| [R4] – Complete Benchmark GMD Vulnerability Assessment | ISO | 1/1/2023 | 7/1/2022 |
| [R5] – Provide Benchmark GIC Flow Information to Applicable TOs and Lead MPs for Applicable GOs | ISO | 1/1/2020 | 12/1/2019 |
| [R6] – Complete Benchmark GIC Thermal Impact Assessment on > 200 kV BES Transformers | App. TOs/App. GOs | 1/1/2022 | 1/1/2022 |
| [R7] – Develop Corrective Action Plans, as Needed | ISO/App. Entities | 1/1/2024 | If needed, complete ASAP, but definitely by 1/1/2024 |
| [R8] – Complete Supplemental GMD Vulnerability Assessment | ISO | 1/1/2023 | 7/1/2022 |
| [R9] – Provide Supplemental GIC Flow Information to Applicable TOs and Lead MPs for Applicable GOs | ISO | 1/1/2020 | 12/1/2019 |
| [R10] – Complete Supplemental GIC Thermal Impact Assessment on > 200 kV BES Transformers | App. TOs/App. GOs | 1/1/2022 | 1/1/2022 |
| [R11] – Implement Process to Obtain GIC Monitoring Data | ISO/TPs | 7/1/2021 | 3/31/2021 |
| [R12] – Implement Process to Obtain Geomagnetic Field Data | ISO | 7/1/2021 | 3/31/2021 |

TPL-007 compliance timeline | *ISO-NE*

## ISO-NE News

# FERC Rejects New England Tx Rate Settlement

*By Michael Kuser and Robert Mullin*

| Central Maine Power

FERC on Wednesday rejected a contested offer of settlement on network service rates for a group of New England transmission owners (NETOs) (*ER18-2235, EL16-19*).

The settlement proposed new rates and a new rate design for regional network service (RNS), local network integration transmission service (LNS) and point-to-point (PTP) transmission service for all the TOs in the region. It would have replaced the existing RNS and LNS rates with new formula rate templates and associated protocols. The PTP rates fall under the same Tariff schedule as LNS.

FERC instituted the proceeding in December 2015, saying ISO-NE's Tariff "lacks adequate transparency and challenge procedures" on the NETOs' formula rates and that the network rates "lack sufficient detail" to determine how costs are derived and recovered.

In responding to requests for rehearing of its December 2015 order that established hearing and settlement judge procedures over the matter, the commission noted that it would not be possible to ensure the justness and reasonableness of the transmission rates in the ISO-NE Transmission, Markets and Services Tariff unless the NETOs "were all considered together in a single proceeding due to the possibility of a mismatch in the synchronization of the rates, timing of true-ups, cost allocation or methodology for calculating the RNS rate and LNS rates."

Last September, the New England States Committee on Electricity (NESCOE), New England Power Pool Participants Committee and the NETOs separately filed comments in support of the settlement, while municipal utilities individually submitted comments in opposition.

The municipals contended that the settlement disadvantaged them by imposing costs for local — or "non-pool" — transmission facilities that provide them with no material benefit. They also contested the settlement's inclusion of a five-year moratorium prohibiting Federal Power Act Section 205 or Section 206 filings to change the settlement. They argued that it was "heavily lopsided" because it would have subjected non-settling parties to the "most stringent standard of review under applicable law" in challenges under Section 206 while its exceptions "essentially eliminate most constraints that a moratorium would otherwise impose on the Section 205 filing rights of a transmission-owning utility."

FERC trial staff argued that the settlement was unfair because it contained unreasonable rates and "contains fundamental defects." Staff cited the TOs' ability to: conduct "extra-formulaic, ad hoc" ratemaking for all externally sourced inputs every year; over-recover certain plant costs; and recover a return greater than 50% of funding for construction work in progress.

In its order rejecting the settlement, FERC noted that under the approach outlined in its Trailblazer decision, the commission may approve a contested settlement if it determines that "the contesting party's interest is sufficiently attenuated that the settlement can be analyzed under the fair and reasonable standard applicable to uncontested settlements" and that it makes an independent finding that the settlement benefits the "directly affected" settling parties.

"Here, there are two obstacles to this approach," FERC wrote. "First, the record is insufficient to determine whether the settlement's benefits outweigh the objections to it; in fact, contesting municipals present evidence that there is more harm than benefit. Second, the parties who are directly affected by the settlement's RNS and LNS rate calculation provisions include both parties who support the settlement (NETOs) and those who oppose the settlement (contesting municipals)."

The commission said that based on "the overall lack of necessary detail and transparency," it could not accept the settlement, and it remanded the proceeding to the chief judge to resume hearing or settlement procedures.

The next day, the chief judge issued a procedural order assigning a hearing judge, a procedural track for the hearing, and a dispute resolution specialist to serve as a settlement facilitator.

The NETOs are Central Maine Power; Emera Maine; Eversource Energy Service; Fitchburg Gas and Electric Light; Maine Electric Power; National Grid; Unitil Energy Systems; United Illuminating Co.; Vermont Electric Power Co.; and Vermont Transco. ■

## MISO News

# MISO Undecided on Amending Storage Plan

*By Amanda Durish Cook*

CARMEL, Ind. — MISO is still pondering whether to amend its Order 841 compliance filing, after FERC earlier this month rejected multiple requests to alter the landmark order requiring RTOs to provide storage resources access to their markets.

As part of its May 16 ruling (*Order 841-A*), the commission rejected MISO's requests to reconsider compliance deadlines and consider a phase-in for minimum size requirements for storage participation. (See *FERC Upholds Electric Storage Order*.)

Kevin Vannoy | © *RTO Insider*

"MISO is still reviewing Order 841-A," Kevin Vannoy, the RTO's director of market design, said at an Energy Storage Task Force (ESTF) meeting Thursday. "To the extent in our review of the order that we need to review our compliance filing, or amend it, we may or may not do that. We're still deciding."

In the meantime, MISO is waiting on FERC to act on its compliance filing, which includes both a request to delay a storage participation model until 2021 and limit the participation of storage resources 1 MW and smaller to 50 in the first year of compliance and 150 in the second year. (See *MISO Requests Storage Compliance Delay into 2021*.) MISO has said it will gradually increase the number of small storage devices in its market as it "improves its software's capability to manage them."

RTO staff have said they expect a response from the commission in July, and Vannoy reminded stakeholders that MISO's filing is still open for comments.

"FERC has time to review and folks can comment," he said.

MISO has said its phased approach is a "reasonable precaution to proactively address the potential for large numbers of small electric storage resources, rather than waiting to react to adverse impacts of future high volumes of small electric storage resources."

But FERC maintains that benefits of increased competition will outweigh complexity and implementation costs.

In Order 841-A, the commission said the 100-kW minimum size requirement is a "balance between the benefits of increased competition fostered by the opportunity for smaller resources to participate in the RTO/ISO markets … and the potential need to update RTO/ISO market clearing software to effectively model and dispatch these smaller resources."

"We continue to believe that, given the record showing that all RTOs/ISOs are already accommodating the participation of smaller resources in their markets and the commission's willingness to consider requests to increase the minimum size requirement in the future, we are providing the RTOs/ISOs with adequate time to develop the requisite tariff language and update their modeling and dispatch software to comply," FERC said.

The commission repeated its position that any RTO experiencing difficulty calculating the market after an influx of storage participation could file a request to increase the minimum size requirement. It also pointed out that its compliance directives don't include any of the distributed energy resource aggregation rules that were first considered in its original Notice of Proposed Rulemaking, making compliance less burdensome.

"We continue to find that the timeline for compliance and implementation is reasonable," FERC said, adding that it will not allow individual RTOs to propose their own compliance timelines.

Vannoy said MISO's request for delay had lined up with the early delivery of its new market system platform by a third-party vendor in 2021.

### Next up: Hybrid Resources

The Thursday meeting was the last in-person meet-up of the ESTF before it sunsets next month after a year and a half of service. The group will provide a final report of potential storage topics to the Steering Committee, which will route the items to the appropriate stakeholder committees for possible policy development.

Entergy's Yarrow Etheredge asked if MISO should consider extending the life of the ESTF because of the uncertainty surrounding the Order 841 compliance filing and a decision is not expected until July.

Task force Chair John Fernandes said stakeholders might consider *ad hoc* meetings focusing on energy storage, but monthly meetings of the ESTF were no longer necessary.

The final meeting of the Energy Storage Task Force on May 23 | © *RTO Insider*

"Where there is interest in discussing this further, it would be on an as-needed basis," Fernandes said.

The ESTF's topic list focuses heavily on how MISO might facilitate market participation for hybrid resources that include both generation and energy storage devices. The group said the RTO should work out how modeling, forecasting and offer data submittals will work for those resources. MISO must also determine allowable capacity factors for the purposes of its Planning Resource Auction. It currently lacks historical data on the charging patterns and behavior of hybrid resources, making capacity factors difficult to determine.

Some stakeholders agreed that hybrid resources are a more pressing matter than storage-as-transmission assets (SATA) because they believe multiple hybrid resources will be built before a SATA project is realized. Others added that if MISO wants to incorporate hybrid resources soon, it needs to rethink its postponement on combined cycle modeling until mid-2023. (See "At Least 1 Market Project Delay," *New MISO Platform Headed to the Cloud*.) Multiple stakeholders said better combined cycle modeling and hybrid resource modeling are inextricably linked. ■

## MISO News

# Xcel Latest MISO Utility to Pledge Zero Coal

*By Amanda Durish Cook*

Minnesota's Xcel Energy is aiming to be coal-free by 2030, supported by extending service of its nuclear plant and using more natural gas-fired generation, the utility announced last week.

The company on May 20 announced that it will close its two remaining coal plants a decade earlier than originally scheduled but extend operation of the Monticello Nuclear Generating Plant on the Mississippi River into 2040, 10 years after the plant's current license expires. The nuclear extension will require both state and federal approvals.

The 511-MW *Allen S. King Generating Station* near the Twin Cities will close in 2028, while the 876-MW Sherco III unit of the *Sherburne County (Sherco) Generating Station* will close in 2030, Xcel *said* in a press release. The company has already said it will shutter the 680-MW Sherco I and 682-MW Sherco II in 2023 and 2026, respectively. It plans to build a new natural gas plant on the Sherco site.

The announcement comes as Xcel comes closer to securing the purchase of the gas-fired *Mankato Energy Center* from Southern Co. for about $650 million — a move originally opposed by the Sierra Club, which removed its comments in opposition after Xcel's announcement (*18-702*).

The company said the changes will take place while it triples its renewable portfolio, with plans to add 1,850 MW of wind by 2022 and about 3,000 MW of new solar by 2030.

Xcel said the acceleration of eliminating coal dependence "is another milestone in the company's clean energy transition."

The company will submit the retirement proposals, included in its 15-year resource plan, to the Minnesota Public Utilities Commission on July 1. The company has said it plans to reduce carbon emissions to 80% below 2005 levels by 2030 and go completely carbon-free in 2050.

"This is a significant step forward as we are on track to reduce carbon emissions by more than 80% by 2030 and transform the way we deliver energy to our customers," said Chris Clark, president of Xcel Energy in Minnesota, North Dakota and South Dakota.

After the Xcel retirements, Minnesota will be left with just one coal plant, Minnesota Power's 1,000-MW Boswell power plant in Cohasset.

Xcel's move also comes after Minnesota Gov. Tim Walz announced in March that the state would strive to use 100% clean energy by 2050, joining Wisconsin, which has a similar goal. The company joins a spate of MISO member companies that have pledged to go coal-free or carbon-free, including MidAmerican Energy, DTE Energy, Consumers Energy and Southern Co. Other MISO companies have deep carbon-reduction goals, including American Electric Power, Alliant Energy, Ameren, NextEra Energy and WEC Energy Group.

As a result, some MISO organizations and companies have asked the RTO to better account for significant renewable goals or decarbonization commitments in its transmission planning. (See *MISO Going Back to the Futures for MTEP 20*.) ■

Sherco Generating Station | *Xcel Energy*

## MISO News

# Outside Parties Slow MISO-PJM Freeze Date Thaw

*By Amanda Durish Cook*

After five years of discussion, MISO and PJM are still slogging through development of an alternative to their "freeze date" used to grandfather permissible unscheduled transmission flows that predated their seam.

And while the RTOs promise progress on the issue, they acknowledge that outside entities with a stake in any changes are still resistant to a proposed solution, stakeholders learned May 21.

The RTOs rely on the April 1, 2004, "freeze date" to determine firm rights on flowgates based on historical firm flows that occurred before creation of the seam between their markets. That date is used to establish acceptable flows in both the market-to-market (M2M) process and transmission loading relief.

Andy Witmeier, of MISO's seams administration team, said the RTOs still agree that the freeze date needs updating.

"We're more than 15 years away from it now, and issues with the date have become prominent," Witmeier told stakeholders during a MISO-PJM Joint and Common Market conference call. Those issues primarily have to do with how designated network resources are dispatched and determining eligibility for transmission service requests.

But five years on, the RTOs are still facing opposition from parties to their congestion management process (CMP), which includes MISO, PJM, SPP, the Tennessee Valley Authority, Manitoba Hydro, the Minnkota Power Cooperative and Associated Electric Cooperative Inc. The CMP was established to minimize unscheduled market — or loop — flows among neighboring balancing areas.

All CMP parties stand to be affected by a change in the freeze date, MISO staff have said.

In November, MISO and PJM announced that their original goal of a full freeze date replacement by June 2019 was too optimistic. Now, the RTOs say they will continue talks on a possible replacement throughout the year and hope to implement a solution in 2020.

### FFE vs. FFL

In M2M procedures between RTOs, an RTO's entitled firm usage is classified as a firm flow entitlement (FFE). In the transmission loading relief process utilized for nonmarket entities in the CMP, an RTO's entitled firm usage is classified as a firm flow limit (FFL).

Witmeier said MISO and PJM were close to a solution last year, but that nonmarket entities party to the CMP had issues with how the proposal might impact FFLs.

The RTOs' proposal would divide flowgate allocation — or FFEs — among four separate "buckets" to prioritize access to the flowgates. (See "Freeze Date Update," *MISO-PJM Markets Meeting Addresses Seams Issues*.)

The first bucket — which would get primary consideration for flowgate needs — would consist of active designated network resources predating the freeze date and historic transmission service requests.

A second bucket would consist of active designated network resources dating after the freeze date, while a third would be used for transfers from local balancing authorities with excess generation to LBAs short on generation.

The fourth, lowest-priority bucket would be for market-wide transfers based on RTO transmission planning.

MISO and PJM last summer changed their policies to make post-freeze date designated network resources with a defined dispatch order eligible to receive FFE allocations — a small piece of the RTOs' broader proposed solution.

Witmeier said most CMP entities favor completing an FFE solution by mid-2020 while continuing to work on how FFLs would be handled. However, some want any solution delayed until both FFEs and FFLs can be addressed.

"Obviously, we have to have a unanimous agreement from all parties. … We're not there yet," Witmeier said.

### 'A Long Time'

MISO, PJM and CMP entities have been working for about five years on a freeze date alternative through their Congestion Management Process Working Group.

Witmeier also said the two RTOs are specifically working on how to account for FFE allocation priorities and in what order they would curtail the overallocation of rights on a particular flowgate.

A joint white paper on the matter that would detail an alternative way to calculate the freeze date is still in the works, Witmeier added.

Customized Energy Solutions' David Sapper asked if MISO and PJM could move to a FERC filing on a freeze date alternative without all nonmarket entities signing on.

"Five years is a long time," Sapper observed.

PJM Director of Energy Market Operations Tim Horger said the two RTOs are considering substitutes to unanimous accord and may consider a filing that not all parties have signed on to. He also said parties to the CMP are "frustrated" that talks on a potential solution have taken this long.

"There is going to be a path forward shortly," Horger promised stakeholders.

MISO and PJM staff promised to return to the Aug. 27 JCM meeting with an update. ■

| © RTO Insider

## MISO News

# MISO Steering Committee Advances Roadmap Suggestions

*By Amanda Durish Cook*

MISO's Steering Committee last week routed eight new market improvement proposals to stakeholders for debate and prioritization by voting.

During a Wednesday conference call, the Steering Committee said eight of the 11 ideas submitted met the criteria to be considered in the *Integrated Roadmap* list of market improvements due later this year. They will be ranked by staff and stakeholders alongside existing Roadmap ideas from previous years.

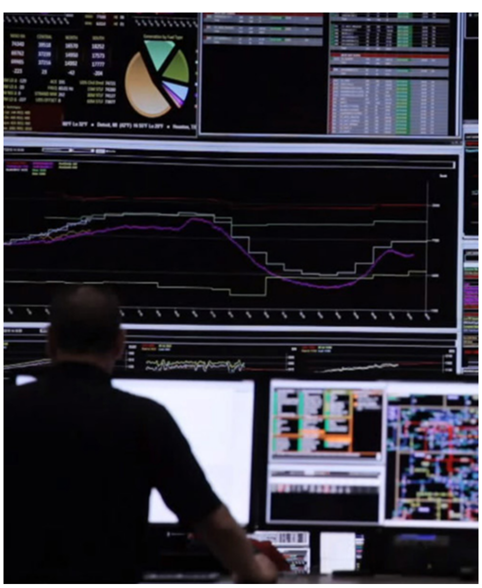
The Steering Committee does not debate the merits of Roadmap candidates, leaving that instead to the Market Subcommittee and the Resource Adequacy Subcommittee.

### Main Line Ideas

The package contains three ideas from Main Line Generation, including a *suggestion* that MISO include energy efficiency measurements in its load forecasting method.

"At present, there is no clear articulation of the process by which energy efficiency measures are included in the demand side of the MISO Planning Resource Auction," Main Line said.

Some Steering Committee members argued that the proposal was a waste of time because energy efficiency only accounts for about 312 MW of capacity in the footprint and that stakeholders have already spent enough time on the matter. Nevertheless, the item was moved for Roadmap consideration.



MISO control room | *MISO*

Main Line also recommended that MISO develop a way to *verify* the accuracy of coincident peak load forecasts provided by load-serving entities. While the RTO conducts a random sampling to check load forecasts, Main Line called the current method an "opaque process where stakeholders and MISO are not provided with a detailed understanding of the key drivers of the large majority of the load forecasts provided."

Finally, Main Line asked that MISO *adopt* a sloped demand curve in its capacity auction. This is the first time the oft repeated call for a sloped demand curve has ever made it to the Roadmap process.

### Monitor Recommendations

The committee advanced two ideas from Independent Market Monitor David Patton, who recommended the RTO use a lower generator shift factor (GSF) cutoff for transmission constraints with limited relief. MISO currently employs a 1.5% GSF cutoff to identify which generators to optimize in its dispatch when managing the flows on a constraint, but the Monitor *said* that policy "eliminates most or all of the economic relief available" for some constraints.

Patton also *said* MISO should reduce the unpredictability of its emergency pricing by implementing fixed default floors. Emergency pricing default floors are currently set by a supplier's offer, which can result in them being either too high or too low under different circumstances, Patton said. He also said the RTO should better calculate megawatt limits on its North-South contract path during emergency pricing events.

### Other Recommendations

Among the remaining ideas was a recommendation by Indianapolis Power & Light that MISO *introduce* a financial incentive for market participants providing primary frequency response, in line with the company's unsuccessful 2016 FERC complaint. MISO had placed the item in its Roadmap "parking lot" in 2018, putting discussion on hold.

Clean Grid Alliance asked MISO to begin preparations to *move* to a "universal participation model" that would "eliminate the need for technology-specific generator models." The group said the removal of standard generator models would allow any technically capable resource to participate in the RTO's markets. CGA's Natalie McIntire clarified that the group is only proposing that MISO scope the system changes required to forgo differing models sometime in the future.

Finally, MISO Market Strategy Adviser Lakisha Johnson said the RTO should focus on improving its scarcity pricing and price formation so it can meet needs across all hours and during scarcity pricing in nonemergency events. "Continuously improving scarcity pricing provides incentives for resources to follow MISO's dispatch," Johnson *said*. Some Steering Committee members criticized the idea as too broad.

### Direct Path to Stakeholders

Three ideas from Patton were not included in the Roadmap package, instead going directly before other committees for discussion or because they were already being considered as part of the ongoing Resource Availability and Need (RAN) effort. Those ideas include:

- A recommendation that MISO *improve* capacity accreditation in the long term by establishing accreditation on resource availability "during high-load or tight supply periods." Steering Committee members said the idea was best included in the RAN project, which already aims to evaluate the overall process of capacity accreditation.
- A recommendation that MISO improve outage data for capacity calculations by *treating* unreported outages and derates as forced outages and accounting for the fact that "forced outages may occur when a resource would not have been dispatched." The Steering Committee said the issue is already being considered in RAN discussions.
- A suggestion that MISO improve the calculation of capacity requirements by factoring in the obligation to serve behind-the meter load and accounting for the lead times of load-modifying resources and other emergency resources in the loss-of-load expectation (LOLE) study. Patton *said* MISO's LOLE studies "essentially assume that [LMRs and emergency resources] provide more reliability value to the system than they do in reality."

Meanwhile, the eight forwarded ideas will go before stakeholders for ranking next month. MISO has planned an Aug. 8 stakeholder *workshop* to review the prioritization of improvements. A final report on how it will order the improvements in the Roadmap won't be complete until November. ■

# NYISO Management Committee Briefs

## Comprehensive Reliability Plan OK'd

RENSSELAER, N.Y. — NYISO's Management Committee last week recommended that the Board of Directors approve a Comprehensive Reliability Plan (*CRP*) that identified no reliability needs over the coming decade but did point to risks that could develop over the period.

NYISO Senior Manager for Reliability Planning Kevin DePugh on May 20 presented a *summary* of the 2019-2028 plan, which included a scenario on the reliability impacts of proposed environmental regulations on 3,300 MW of peaking units, predominantly in New York City (Zone J) and Long Island (Zone K).

The state's Department of Environmental Conservation earlier this year proposed to lower allowable NOx emissions from simple cycle and regenerative combustion turbines (SCCTs) during the ozone season, beginning May 1, 2023. (See *NY DEC Kicks off Peaker Emissions Limits Hearings*.)

NYISO, Consolidated Edison and PSEG Long Island said losing all the peakers without replacement resources or system reinforcements would threaten reliability in pockets in New York City, Long Island and southeast New York.

"Starting in 2023, with the first implementation phase of the rule, pockets in New York City would be deficient of supply for up to 14 hours in a given day at a peak amount of 240 MW, while pockets in Long Island would be deficient 320 MW possibly for 15 hours in a given day. With full implementation of the peaker rule assumed in 2025, the New York system as a whole would significantly exceed the probability of one loss-of-load event in 10 years due to a supply deficiency of at least 700 MW in southeast New York," the report said.

"One thing generators will have to do by [March 2020] is put in compliance plans, and if they plan on closing a plant, they would have to submit a deactivation notice to the ISO," DePugh said.

If NYISO can prove the loss of such a unit will create a reliability need for which it can find no alternative solution, it can get a two-year extension to keep the unit online, followed by an additional two years if necessary, DePugh said.

Working with Con Ed, the Long Island Power Authority and PSEG LI, the ISO found at least 700 MW of capacity needed in Zones J and K to meet loss-of-load expectation criterion, assuming the state's AC Transmission projects are completed on schedule by December 2023. (See *NYISO Board Selects 2 AC Public Policy Tx Projects*.)

Local transmission alone cannot fully solve the needs, and upgrading the transmission path from UPNY-SENY into Zones J and K would likely bring the New York Control Area at or only marginally below the LOLE criterion, the report said. It would not address the local transmission constraints identified in J and K.

"The solutions could be a mix and match of different things," DePugh said, including a combination of local transmission, resource additions and load reductions.

## MMU Recommendations

Pallas LeeVanSchaick of the Market Monitoring Unit *reviewed* the CRP, as required by the Tariff, and confirmed that transmission security and resource adequacy needs could arise if a number of plants retire.

"There are really six load pockets, three in New York City and three on Long Island, where additional resources would be needed," LeeVanSchaick said.

| *PSEG Long Island*

The CRP found the violations could be avoided through a variety of solutions, including by retaining 1,280 MW of peaking capacity in specific areas.

The MMU recommends NYISO adopt three significant market reforms, starting with modeling in the day-ahead and real-time markets Long Island transmission constraints — which the ISO currently manages with out-of-market actions — and developing mitigation measures to address them.

"A lot of congestion on Long Island is managed outside the market, which doesn't provide much transparency about congestion bottlenecks or incentives for investment," LeeVanSchaick said. "There are certain areas where it is less expensive to build generation than other areas, so price signals have to be adequate to attract investment where it is needed for reliability."

The Monitor also recommends the ISO model local reserve requirements in New York City load pockets and consider rules for efficient pricing and settlement when operating reserve providers also provide congestion relief benefits.

| | | Removed in 2023 & 2024 (starting 2021 for coal) | | | Additional MW removed starting 2025 (throughout the study period) | | | Total Removed by 2025 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Name Plate | ICAP | DMNC | Name Plate | ICAP | DMNC | Name Plate | ICAP | DMNC |
| Coal | Zone A & C | 810 | 840 | 840 | 0 | 0 | 0 | 810 | 840 | 840 |
| Peaking Units | Zones A-I | 132 | 107 | 107 | 0 | 0 | 0 | 132 | 107 | 107 |
| | Zone J | 1,066 | 841 | 846 | 692 | 582 | 585 | 1,758 | 1,423 | 1,431 |
| | Zone K | 1,039 | 960 | 968 | 406 | 389 | 389 | 1,445 | 1,349 | 1,357 |
| | | | | | | | **Total** (including Coal) | 4,145 | 3,719 | 3,735 |
| | | | | | | | **Total Peaking Units Only** | 3,335 | 2,879 | 2,895 |

Chart shows the expected retirement timelines for various peaking units across New York. | *NYISO*

# NYISO News

## NYISO-PJM JOA Revisions

The MC approved *revisions* to NYISO and PJM's Joint Operating Agreement, as recommended by the Business Issues Committee. The revisions will go to the ISO's board in June ahead of a joint FERC filing.

Under the changes, the determination of redispatch settlements would exclude several flowgates, said Cameron McPherson, the ISO's operations analysis and services analyst.

FERC last September granted a one-year waiver of the JOA to permit the addition of the East Towanda-Hillside tie line as a market-to-market (M2M) flowgate. (See "NYISO, PJM Revising JOA for Tie Line Issues," *NYISO Business Issues Committee Briefs: March 13, 2019*.)

The proposed JOA revisions were developed to address the concern raised in the waiver request and to improve other components of the M2M coordination process — in particular, the rules for performing entitlement calculations.

## New External SRE Penalty

The committee approved a new external supplemental resource evaluation (SRE) penalty regime that would boost the ISO's ability to call on external resources that have sold capacity to New York. The changes, approved by the BIC in April, will take effect in the third quarter.

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

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

Howard Fromer, director of market policy for PSEG Power New York, said he hoped that NYISO would include in its FERC filing a mention of stakeholder concerns about being scrutinized for performing the bidding "gymnastics" called for under the proposed penalty scheme.

LeeVanSchaick said the Monitor is aware of those stakeholder concerns and that the ISO would mention them in the filing.

Under the new penalty provisions, the ISO will calculate deficiencies monthly, using the total number of SRE call hours in a given month that the resource could be online for and the total number of megawatts of shortfall in that month, Carney said.

## Collateral Change for Foreign Market Participants

The MC also approved a Tariff change restricting the posting of cash collateral to entities based in the U.S. and Canada.

The changes affect only four market participants, said Sheri Prevratil, manager of corporate credit.

Market participants that do not meet Tariff requirements for unsecured credit must post cash, letters of credit or surety bonds as collateral.

In the event of a bankruptcy, the ISO's ability to retain a company's cash collateral is dependent on applicable bankruptcy laws. Given the potential number of jurisdictions at issue worldwide, it is not feasible for the ISO to evaluate laws in all jurisdictions to ensure its interest in cash collateral would be adequately protected, Prevratil said.

The board will consider the measure in June ahead of a planned FERC filing. ■

*— Michael Kuser*

## PJM News

# PJM MRC Preview

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

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

### Consent Agenda (9:15-9:25)

B. Endorse proposed revisions to Manual 01: Control Center and Data Exchange Requirements as a part of the cover-to-cover review.

C. Endorse proposed revisions to Manual 03: Transmission Operations as a part of a cover-t to-cover review.

D. Endorse proposed revisions to Manual 07: PJM Protection Standards to update applicability references and an Institute of Electrical and Electronics Engineers standard reference.

E. Endorse proposed revisions to Manual 11: Energy & Ancillary Services Market Operations and Manual 13: Emergency Operations to clarify the impact of operationalizing gas contingencies on reserve requirements and reserve market eligibility.

F. Endorse proposed revisions to Manual 13: Emergency Operations as part of a cover-to-cover review.

G. Endorse proposed revisions to Manual 36: System Restoration as a part of a cover-to-cover review.

### 1. Fuel Security Senior Task Force Charter

Stakeholders will get a first look at the *charter* for the newly formed Fuel Security Senior Task Force, two months after a lengthy debate over whether the discussion was even necessary. (See *PJM Stakeholders Reluctantly OK 'Fuel Security' Initiative*.)

The draft charter fleshes out the details of the compromise problem statement and issue charge stakeholders spent more than two hours haggling over at the March MRC meeting, including an open-ended timeline that doesn't commit stakeholders to action by the end of the year. PJM will seek endorsement at the June MRC meeting.

### 4. FERC Order Related to Hourly Cost Offers

PJM will present an update on fuel cost policies after FERC accepted the RTO's March compliance filing that clarifies:

- Clearly specifying when a penalty for non-compliance with a fuel-cost policy would be terminated by PJM.
- Allowing a new resource a 90-day time period before it submits its fuel-cost policy.
- Specifying that a market seller may only update its minimum run time for the uncommitted hours in real time and that a market seller's make-whole payment be based on the minimum run time specified at the time of commitment.

FERC also reaffirmed the Independent Market Monitor's right to oppose PJM filings on issues beyond market seller offers in capacity auctions (ER16-372). (See *FERC Upholds PJM Monitor's Right to Protest Fuel-cost Policies*.) ■

*— Christen Smith*

## PJM News

# Va. Group Seeks End to Dominion Monopoly

Continued from page 1

"For too long we have allowed the energy industry and those masquerading as electric utilities to chart our energy future," said Dan Holmes, director of state policy for the Piedmont Environmental Council, during VERC's May 7 press conference. "They have crafted the legislation and relied on their campaign contributions and lobbying prowess to ensure it is signed into law. The net result is a system that works for them alone, holding the commonwealth captive, all at the expense of the ratepayer."

Dominion contributed more than $452,000 to state candidates and committees last year, according to the Virginia Public Access Project, making it the commonwealth's largest campaign donor within the energy sector.

"Yes, the utilities are quite influential," said Jim Presswood, executive director of the Earth Stewardship Alliance, another VERC member. "But our coalition represents consumers and groups across the ideological spectrum who plan to let their elected officials know that the time for reforms is now."

### IDSO

VERC argues it's time for lawmakers to decouple utility companies from power generation — allowing for smaller, cheaper and cleaner resources to enter into the marketplace. The coalition looks to ERCOT's structure as inspiration, noting Texas' decision to "quarantine" utilities to owning transmission and distribution lines. Such a policy in Virginia could pave the way for more distributed energy resources, including solar and storage, to come online, the group says.

But the group does not want Virginia to create its own ISO. Instead, it supports the establishment of streamlined interconnection standards implemented by an independent distribution grid operator (IDSO).

"An IDSO would be similar to an RTO, but at the distribution level," Presswood said. "The IDSO would operate and plan the distribution grid. The utilities would own and maintain the grid. There is not a conflict with PJM because the IDSO would not run any markets."

An IDSO would also ensure an "all-cost-effective" energy efficiency standard by issuing private sector bid solicitations to remedy "significant" discrepancies that may require system upgrades.


Jim Presswood, executive director of the Earth Stewardship Alliance, speaks at the Virginia Energy Reform Coalition's launch on May 7. | *Piedmont Environmental Council*

"Competitive markets may not deploy energy efficiency resources even though they may be a cheaper way to meet system needs than other methods such as building new power plants or transmission and distribution infrastructure," Presswood said. "If a competitive market were already deploying most or all cost-effective energy efficiency resources, there would be no need for IDSO intervention."

The coalition also says the proliferation of DERs means there is no need for a capacity market, calling it an outdated structure that causes overinvestment, excess costs and unequal treatment of energy resources. It says it wants to "phase out" the capacity market and move to an ERCOT-like resource adequacy model, though it does not say how exactly it would accomplish that.

### Costly Move?

Both Dominion and Appalachian Power doubt the proposed reforms make sense for Virginia, citing higher electricity prices in neighboring deregulated states. The legislature established a competitive model in 1999, but a failure to gain traction with customers and suppliers led to its undoing just eight years later.

"By owning and operating a diverse, clean generation fleet within PJM, our customers are protected from price volatility and market changes," said Julie Mills Taylor, spokesperson for Dominion. "Being a member of PJM does provide a level of integrated transmission and generation planning that provides reliability assurances across a regional footprint."

John Shepelwich, spokesperson for Appalachian Power, said Edison Electric Institute data published in April showed industrial customers paid rates 78% higher during the last winter in deregulated states. Residential rates were likewise 37% more expensive, according to EEI.

"We would expect that if Virginia were to deregulate generation services, it would probably result in the need to collect many millions of dollars in our plant investments made to meet longstanding obligations to serve our customers here," he said. "That would be in addition to paying market-based generation service costs under a new regime."

VERC also wants to change the way electricity rates are structured, said Travis Kavulla, director of energy policy for the R Street Institute. Instead of collecting revenues based on cost inputs and a desired return — the cost-of-service model — the coalition prefers basing rates on utility performance.

"The coalition's agenda strikes a fair-minded balance between customer empowerment and customer protection," he said. "Both of which are things Virginia energy policy has needed more of for years."

Presswood said he expects legislation fleshing out VERC's *platform* will be introduced next year. ■

## SPP News

# OG&E Acquires 2 Oklahoma Plants

Oklahoma Gas and Electric said Wednesday it has completed the acquisition of two Oklahoma generators from which it had previously bought power to meet its capacity needs.

Oklahoma Cogeneration plant | *Oklahoma Cogeneration*

OG&E said FERC's approval of the transactions (*EC19-49*) was the final regulatory OK it needed to complete its purchases. Financial terms were not disclosed, but OG&E said last year it would spend $53 million to acquire the plants.

AES Shady Point is a 360-MW, coal-fired facility in Eastern Oklahoma; privately owned Oklahoma Cogeneration is a 146-MW combined cycle plant in Oklahoma City.

OG&E, a subsidiary of Oklahoma City-based OGE Energy, had contracts with both resources under the Public Utility Regulatory Policies Act of 1978. The legislation requires utilities to buy power from cogeneration plants built by non-utility power producers when the costs for that power are equal to or less than what the utility would spend to produce that power from a facility it would build and own.

Shady Point qualified for the cogeneration requirement by using some of its carbon dioxide emissions as a liquid and solid food-grade refrigerant for the poultry industry. However, OG&E said last year it was ending a five-year power purchase agreement with the plant, leading AES to announce it would close the facility.

OGE Energy CEO Sean Trauschke has said he expects "operational changes" to reduce Shady Point's coal usage by more than 50%. The plant came online in 1991.

Spokesman Brian Alford said the acquisitions will save OG&E customers "tens of millions of dollars" annually and keep "good-paying jobs in Oklahoma."

OG&E received approval from Arkansas and Oklahoma regulators earlier this month. ■

*— Tom Kleckner*

Shady Point facility | *AES Shady Point*

# Company Briefs

## NRG Buys Another Power Retailer

NRG Energy last week announced it would buy Stream Energy, a retail power and natural gas business that reaches 600,000 customers in Dallas, in a $300 million deal. The sale, which must be approved by regulators, is expected to close in the third quarter.

NRG is the biggest seller of electricity in Texas, controlling more than 30% of the retail power market. Last year, the company bought Discount Power from Volterra Energy Holdings, a deal that added roughly 225,000 customers.

More: *Houston Chronicle*

## NYISO Board Names Dewey President, CEO

NYISO last week announced that its Board of Directors has named current Executive Vice President **Richard J. Dewey** to be president and CEO, effective June 1.

Dewey, who has been with the ISO for 19 years, replaces Robert E. Fernandez, who has served as interim president and CEO since October 2018. Fernandez will become executive vice president, general counsel and chief compliance officer.

More: *NYISO*

## Musk Tops List of Highest Paid CEOs

Tesla CEO **Elon Musk** was the highest paid chief executive in the U.S. in 2018, according to a survey conducted by the executive compensation consulting firm Equilar last week.

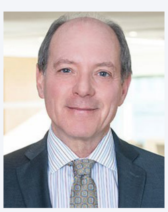
Equilar compiles its rankings from a pool of public companies in the U.S. with annual revenue of at least $1 billion that filed proxies by April 30. Musk earned about $2.3 billion last year, more than the next 65 highest-paid CEOs combined. The second top earner, Discovery CEO David Zaslav, earned about $129 million. Musk's compensation came largely in the form of stock options. Approved by Tesla's board in March 2018, the compensation package awards options to Musk if the company hits specific market capitalization milestones over a decade.

Most of the top 10 CEOs are heads of California-based companies, including Tesla. The Associated Press used Equilar's results to list the highest paid executives by state. Several energy company CEOs represent their respective states: Entergy's Leo Denault, of Louisiana, at 34th; Hawaiian Electric Industries' Constance Lau, of Hawaii, at 38th; PNM Resources' Patricia Collawn, of New Mexico, at 40th; IDACORP's Darrel Anderson, of Idaho, at 41st; MDU Resources Group's David Goodin, of North Dakota, at 45th; and Black Hills' David Emery, of South Dakota, at 46th and last. (Four states do not have a company that qualified for the rankings.)

More: *The New York Times*; *Business Insider*; *The Advocate*

# Federal Briefs

## Jonathan Schneider Elected EBA President



The Energy Bar Association last week announced it has elected **Jonathan Schneider**, as president of its board of directors for 2019-2020.

"We have important opportunities and challenges in the coming year," said Schneider, a partner at Stinson LLP. "Consistent with our educational focus, we will look to enhance access to the content that EBA provides members through our many meetings, energizers and publications, and to provide new opportunities for members to publish position pieces and exchange views on issues of the day."

In addition, the EBA elected the following individuals to be board officers: Jane Rueger of White & Case as president-elect; Mosby G. Perrow IV of Kinder Morgan as vice president; Paul Breakman of the National Rural Electric Cooperative Association as secretary; Delia D. Patterson of American Public Power Association as assistant secretary; Paula Johnson of Ameren as treasurer; and Richard Smead of RBN Energy as assistant treasurer.

## Chatterjee Disputes LaFleur's Comments on Partisan Split at FERC

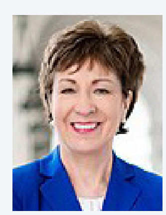
In an interview with S&P Global Platts last week, FERC Chairman **Neil Chatterjee** pushed back hard against the notion that partisanship is coloring the agency's work under his watch or that the White House exerts more influence than it once had.

Chatterjee was responding to a speech made by Commissioner Cheryl LaFleur at the Energy Bar Association's annual meeting earlier this month, in which she lamented that the high turnover and contentious debate over emissions from natural gas infrastructure has affected the commission's work. (See *LaFleur Recounts Turbulent Tenure at FERC*.)

"I wholeheartedly and respectfully disagree," Chatterjee said. "I don't believe that the agency is going through any kind of partisan period that's different from what it's gone through in the past." To make his case, Chatterjee said he had staff quickly crunch the numbers, comparing dissents and orders under his 11 months as chairman to the time period in which LaFleur led the agency. "In the 11 months I've been chair, [there were] more than 1,000 orders, maybe 20 dissents. That's a miniscule portion," he said. During LaFleur's period as chair, the number of orders vis-a-vis dissents is "almost identical," he said.

More: *S&P Global Platts*

## Collins Unveils $300M Energy Storage Bill to Combat Climate Change



Sen. **Susan Collins** (R-Maine) introduced a bipartisan bill last week that would direct the Energy Department to establish a research, development and demonstration program for grid-scale energy storage.

The Better Energy Storage Technology Act would authorize $300 million over five years for the department to partner with the private sector on building at least five grid-scale energy storage demonstration projects by September 2023 that can provide power to the grid for 10 to 100 hours and operate for 20 years.

"Next-generation energy storage devices will help enhance the efficiency and reliability of our electric grid, reduce energy costs and promote the adoption of renewable resources," Collins said. "Our bipartisan legislation would help catalyze the development of this technology that holds great promise in the fight against climate change by supporting clean energy generation, including wind and solar."

More: *Washington Examiner*

# State Briefs

## MARYLAND

### Clean Energy Bill Becomes Law Without Hogan's Signature

A bill passed by the General Assembly to increase the state's renewable energy portfolio standard from 25% by 2020 to 50% by 2030 automatically became law Friday after Gov. **Larry Hogan** declined to sign it

Hogan said the increase wasn't clean enough, and announced his own goal of reaching 100% clean energy in the state by 2040. Though he also declined to veto the bill, he said he is concerned it could send too many jobs out of the state and plans to submit legislation next year to put the state on a path toward his own goal.

The decision to allow the bill to become law without his signature is somewhat of a reversal for the popular Republican, who is at the beginning of his second term and weighing a presidential bid. In 2016, the governor vetoed a bill that required the state to get 25% of its energy from renewable sources by 2020, citing concern over increased electricity rates for taxpayers. The Democratic-controlled legislature, which has a veto-proof majority in both chambers, overrode the veto.

More: *The Washington Post*; *The Baltimore Sun*

## MONTANA

### NorthWestern Seeks Huge Transmission Rate Increase

NorthWestern Energy

NorthWestern Energy is seeking a $40 million rate increase for the use of its transmission lines.

NorthWestern said it is currently under-collecting on its transmission business in the state by $39.5 million a year and wants FERC to approve an average 52.8% rate increase to cover costs of some services, plus a host of specialized rates. It also argued that it has invested $416 million in its transmission facilities during the past 13 years and those costs have not been fully recovered under its current billing scheme.

Talen Energy, which operates Colstrip Power Plant, would face an increase of the nearly $5 million a year under the proposal. REC Silicon, a major employer in the Butte area, would see its rates increase more than $1.5 million. A half dozen renewable energy companies have filed with FERC to intervene in the case.

More: *Billings Gazette*

## NEW JERSEY

### New Brunswick Selects Direct Energy for 50% Solar

The city of New Brunswick has agreed to a renewable energy aggregation program, which it says will result in 50% of its electricity coming from renewable sources.

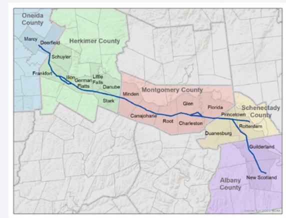
Direct Energy Services won a bid to provide third-party energy to the city at a rate of 0.11386 cents/kWh for 17 months. According to a city spokesman, most of the energy will come from solar fields. The remaining energy will come from wind, geothermal, renewable natural gas, anaerobic digestion, fuel cells and small hydroelectric facilities.

It is the highest percentage of renewable energy used by any community in the state. New Brunswick also hopes to go 100% renewable energy by 2035.

More: *Patch New Brunswick*

## NEW YORK

### NYPA Approves $28M for 1st Phase of Marcy-to-New Scotland




Gov. Andrew Cuomo last week announced that the New York Power Authority's board of trustees approved its $28 million share to begin work on a major new transmission upgrade project in the Mohawk Valley and Capital Region.

The Marcy-to-New Scotland project stems from a proposal by NYPA and LS Power Grid New York to improve reliability and provide better access to renewable energy through a key corridor along the state's transmission system.

The effort was selected by NYISO on April 8 in response to a solicitation process calling for transmission projects along the corridor to relieve congestion and facilitate greater access to renewable energy. LS Power hopes to submit a construction application to the Public Service Commission in the second half of 2019. If all goes smoothly, the rebuilt transmission lines are expected to be in service by late 2023.

More: *Gov. Andrew Cuomo*

## TEXAS

### Abbott Signs State ROFR Legislation

Gov. Greg Abbott has signed into law legislation that gives incumbent utilities the right of first refusal to build transmission projects in the state.

Abbot signed SB 1938 on May 16. It became effective immediately because it had an "emergency" rider attached to it.

The legislation grants certificates of convenience and necessity to build, own or operate new transmission facilities that interconnect with existing transmission infrastructure "only to the owner of that existing facility."

More: *Texas Legislature*



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