RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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Lacking Quorum, FERC OKs ISO-NE Energy Security Plan

By Michael Kuser and Rich Heidorn Jr.

ISO-NE's controversial proposal to compensate resources for maintaining inventoried energy during the winter months is now effective "by operation of law" because of inaction by FERC stemming from a lack of quorum (*ER19-1428-001*).

The commission issued an unusual Chapter 2B notice Aug. 6, saying that the proposal had come effective because FERC had failed to act on it "because of a lack of quorum at this time."

"The ISO will move forward with implementation of the short-term program as we continue working on the long-term, market-based solutions to the region's energy security

ERCOT registered a new all-time demand peak of 74.5 GW as Texas continued to bake in heat extreme even for the Lone Star State. See p10.

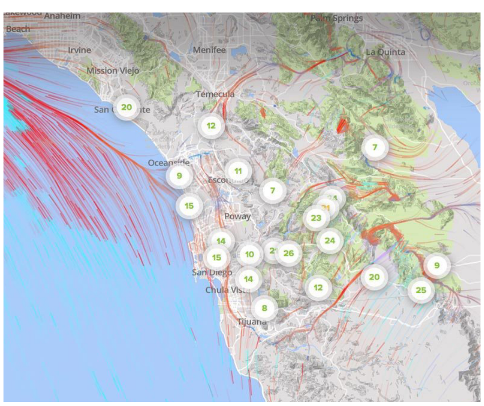
Continued on page 14

Cooperation, Forecasting Key to Calif. Climate Challenges

By Robert Mullin

California must find new approaches to long-term forecasting and collaboration to keep pace with the accelerating effects of climate change on the state's energy system.

That was the key takeaway from a California Energy Commission workshop Thursday focusing on developing strategies for climate adaptation in the state's energy sector.



San Diego Gas & Electric credits its intensive weather monitoring with preventing major wildfires since 2007. | *SDG&E*

For California, adaptation is currently focused on the threat of wildfires and the role power lines can play in igniting them. The fire season is becoming longer in duration, increasingly destructive to natural and built environment, and more disruptive — and deadly — for the state's inhabitants. (See *California Regulators OK Utility Wildfire Plans*.)

"The motivation behind this whole effort is really the stuff that we've seen in the news," said David Saah, managing principal and co-founder of Spatial Informatics Group (SIG). "We've seen a bunch of extreme wildfire events that impact the grid, and as it impacts the grid, it impacts all of us in terms of costs, safety [and] reliability."

SIG describes itself as an "environmental think tank" that combines spatial analytics with ecological, economic and social sciences to gauge the impact of policy decisions on ecosystems. The group is working with the state's *Cal-Adapt* team to "deliver updated wildfire models for improved electric utility grid resiliency and safety" and support California's next *Climate Change Assessment*.

Saah, an associate professor at the University of San Francisco and director of its geospatial

Continued on page 8

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In this week's issue

Counterflow

By Steve Huntoon

Cue the Pixie Dust

By Steve Huntoon

If you're a regular with *RTO Insider*, Greentech Media and the like, you've likely read the accusation that PJM is screwing batteries (motive a mystery).[1]

Here's the backstory. PJM has a capacity market that basically requires that a generator or equivalent resource be "on call" 24 hours a day throughout the year. This Capacity Performance construct arose after the 2014 polar vortex, when it turns out a lot of generators were getting paid for capacity that wasn't actually available when needed.

So CP basically says you as a generator must be available 8,760 hours a year unless you've been preapproved for doing maintenance or refueling. FERC in 2015 found this just and reasonable "because it creates the same expectations for all Capacity Performance resources (i.e., the expectation that such resources will be available to provide energy and reserves *when called upon*), without regard to technology type."[2]

The Big Gift Horse

Flash forward to late last year when, in a big gift horse to the battery industry, PJM proposed that batteries only must provide capacity 10 hours a day, giving them a pass on the other 14 hours in a day. In other words, batteries would have to provide capacity for less than half the time as other dispatchable resources.

Now, the battery industry didn't take this big gift horse lying down.

No. Instead it argues that somehow PJM screwed it.

Its arguments to FERC are all over the map, but the driver is that batteries don't make economic sense unless you require an even smaller supply/discharge obligation like four to six hours. Of course, the economics of a resource should have nothing to do with its value as a resource.[3]

The Latest Salvo

The battery industry's latest salvo is a study by its consultant purporting to show that there could be up to 4,000 MW of batteries in PJM providing only four hours a day of capacity without reducing overall system reliability.[4]

Assuming the study is valid now and for the future, the obvious question is "so what?"

Why should only batteries get the privilege of having to provide capacity for just four hours a day and be excused from the other 20? Every generator in PJM would like to get that same privilege and avoid capacity commitment for 20 hours. It would be the height of discrimination to award that privilege to only one technology such as batteries.

By the way, the battery industry says that four hours are what batteries are "technically capable of," invoking that phrase from FERC Order 841. Of course, batteries also are "technically capable of" a 10-hour duration, as well as a one-hour duration and, frankly, a one-minute duration.

So, should a 10-MWh battery set up to discharge in one minute be given a capacity rating of 600 MW? Nonsense.

More Problems

The problems with batteries go beyond the minimum number of commitment hours. We need to remember that this minimum is a calculation based on maximum output over the period. Maximum output assumes the battery is fully charged when emergency conditions begin.

This is an unrealistic assumption. The economics of a battery are based in part on multiple revenue sources (aka "value stacking"). If used for energy arbitrage, the battery is charging when its operator thinks prices are relatively low and discharging when its operator thinks prices are relatively high. If used for frequency regulation, the battery is charging or discharging in response to the signal (and it can never be fully charged, or it couldn't charge in response to the signal).

The upshot of this is that a battery is seldom "full," meaning it's able to provide its committed capacity when called upon. So at any given time, it's unlikely to provide its committed capacity for the supposedly committed hours.

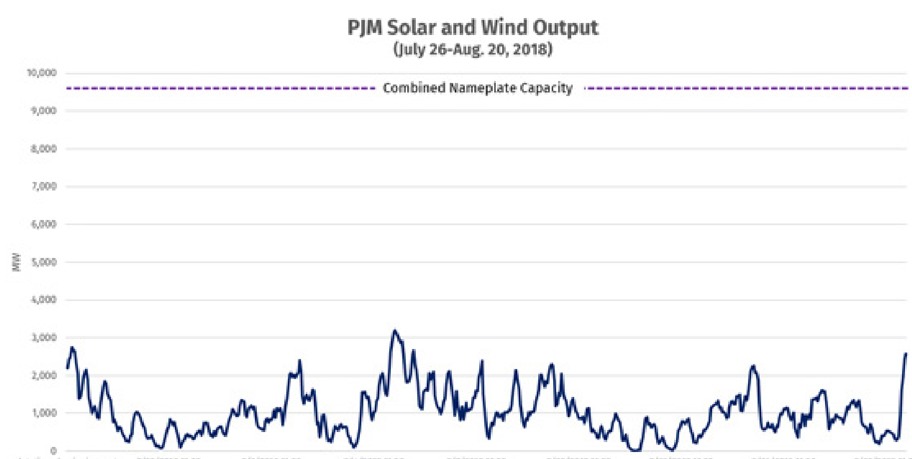
The problem is likely to be acute during peak periods when energy prices are relatively high. Battery owners will be looking to discharge during the peak afternoon hours. And they'll all be doing the same thing at the same time.

So if there's an emergency later in the day, not just one battery but all of them will have no or little charge left. And if they start charging during that emergency, they will make matters worse by appearing on the system as more load to be served.

Where does that electricity come from? Cue the pixie dust.

And here's another problem. Battery advocates assume that over any 24-hour period, batteries can recharge to be prepared for the next day. And in a 100% renewable scenario, they necessarily assume that there are solar and wind renewable resources available to do that day after day as needed.

This is another unrealistic assumption. There are prolonged periods of little solar and wind generation. Last summer in PJM for example, for more than three weeks, there was relatively little solar and wind generation. Solar



For more than three weeks last summer, PJM's solar and wind generation averaged only 10% of their combined nameplate capacity of 9,694 MW. | *PJM*

Counterflow

By Steve Huntoon

Cue the Pixie Dust

and wind generation averaged about *10%* of their combined nameplate capacity of 9,694 MW.[5] The chart on the previous page shows the hourly generation.

Absent traditional resources, where does the generation come from to charge batteries every day? Cue more pixie dust.

Hawaiian Punch

We got a little taste of the problems from Hawaii last month. Here's the headline:[6]

"Island-wide outage on Kaua'i: Clouds block solar recovery after generator's cable failure"

Basically, with clouds blocking the sun, the Kaua'i Island Utility Cooperative had to rely on its battery systems, but doing that discharged the batteries in the afternoon, so they weren't available in the evening, when of course solar generation wasn't available either. Rolling blackouts were necessary.

This is not to knock the cooperative, but rather to show that increasing reliance on renewable resources and batteries presents new challenges.

Media Fantasies

Misleading information is rampant in the media. Just yesterday, *The Wall Street Journal* ran a *story* "Giant Batteries Boost Wind and Solar Plans," including a statement that the utility ScottishPower generates "all of its power from renewable sources after selling its last fossil fuel assets in January." The implication is that this utility is reliably serving its customers exclusively with renewable sources.

The reality is that ScottishPower's *generation* unit has sold off non-renewable assets. ScottishPower continues to serve its retail customers by purchasing capacity and energy from others. For example, in the referenced January asset sale, ScottishPower is purchasing natural gas capacity back from the asset buyer.[7] The last reported fuel mix for ScottishPower's retail sales shows that 73% of its supply is coal and natural gas, 10% is nuclear and only 15% is renewable.[8]

A Dose of Reality from MIT

NPR recently ran an interview with Yet-Ming Chiang, professor of materials science and engineering at MIT, who founded several battery companies. This part of the interview is especially instructive:[9]

"SHAPIRO [NPR]: I know the cost [of batteries] has been prohibitive for a long time, and it's been coming down recently. When do you think this technology will actually be reasonably affordable in a lot of places?

CHIANG: Yes, I think the answer to that question really depends on what the variability in the electricity generation is that we need to cover. Is it just a few hours of the day, for instance in Arizona, or is it a few days or up to a week, right? Today, an electric vehicle battery pack using lithium-ion batteries costs us about $200/kWh. Over time, we can see that dropping to 100 or somewhat less than that. *But with lithium-ion batteries, it's difficult for me to imagine the cost getting down to, let's say $10 or $20/kWh. It turns out that's the price range we need for storing electricity for the grid over several days.* And in order to accomplish that, we really need to look at other battery materials other than lithium-ion batteries."

So the key takeaway, from this MIT battery expert, is that we don't know, at present, how to economically and reliably replace traditional resources.

The Answer isn't Special Treatment

The answer isn't to give batteries a pass on reliability criteria because they facilitate green energy. Support for green energy ends when blackouts begin. That's when the torches and pitchforks come out. ■

[1] *https://rtoinsider.com/study-challenges-pjm-energy-storage-rule-140531/*; *https://pv-magazine-usa.com/2019/07/17/pjms-proposed-10-hour-storage-minimum-debunked/*; *https://energynews.us/2019/07/30/southeast/with-new-study-critics-push-back-on-pjms-proposed-10-hour-storage-rule/*.

[2] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 99 (2015) (emphasis added).

[3] I've written about the overall battery value proposition before, here *http://energy-counsel.com/docs/Grid-Batteries-Kool-Aid-Once-More-with-Feeling-RTO-Insider-12-5-17.pdf*, and here *http://energy-counsel.com/docs/Battery-Storage-Drinking-the-Electric-Kool-Aid-Fortnightly-January-2016.pdf*.

[4] *http://energystorage.org/system/files/resources/astrape_study_on_pjm_capacity_value_of_storage.pdf*.

[5] Solar and wind generation is from PJM's Data Miner 2 here, *http://dataminer2.pjm.com/feed/gen_by_fuel* (average hourly generation in the chart period was 1,018 MW). Solar and wind nameplate capacity is here, *http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q2-som-pjm-sec8.pdf* (page 348).

[6] *https://www.utilitydive.com/news/island-wide-outage-on-kauai-clouds-block-solar-recovery-after-generators/559289/*.

[7] *https://www.drax.com/investors/acquisition-agreement-amended-mitigate-risk-2019-capacity-payments/*.

[8] *https://www.scottishpower.co.uk/about-us/performance/fuel-mix*.

[9] *https://www.npr.org/2019/07/22/744206049/a-new-battery-could-be-key-to-cutting-carbon-emissions-slowing-climate-change* (emphasis added).

FERC/Federal News

Grid Innovation Waiting on DER Rule, Group Says

By Amanda Durish Cook

Nearly 1,000 days have passed since FERC issued a Notice of Proposed Rulemaking to remove barriers to entry from aggregated distributed energy resources participating in the country's wholesale energy markets.

And since then, potential participants in a major grid modernization have been waiting for their cue, top executives with Advanced Energy Economy told *RTO Insider* in an interview.

"It's a long time," AEE Director Dylan Reed said. The NOPR was issued Nov. 17, 2016. The commission also proposed the same treatment for energy storage resources, which eventually led to Order 841 in February 2018, but it said it needed more information on the DER portion before it could take action, opening a separate docket (*RM18-9*). (See *FERC Rules to Boost Storage Role in Markets*.)

"We've had members that say, 'We'd love to participate in these markets, but we can't or are not going to because we don't know what the rules will be.' ... It's regulatory uncertainty that harms investment."

AEE is a D.C.-based trade association representing a gamut of industry players, including those involved in energy efficiency, demand response, solar, wind, electric storage, electric vehicles, fuel cells, combined heat and power and enabling software — as well as large corporate buyers of clean energy (Microsoft, Amazon, Nest and Tesla are among its *members*).

The group is on a mission to identify and eliminate structural barriers to participation in U.S. wholesale energy markets, which it estimates would allow the country's high-tech energy market to expand by $65 billion.

AEE argues that many wholesale market rules are not technology-neutral and have become too outdated to be inclusive. A FERC ruling on aggregated DER participation could jumpstart a more inclusive wholesale market, it says.

Jeff Dennis, the group's managing director and general counsel, contends RTO market rules are still generally rooted in the past and designed with older generation in mind.

"These barriers to participation come in various different forms today," Dennis said.

"Some are explicit barriers, but a lot of them are implicit barriers," Reed added.

Reed pointed to MISO's Tariff, which explicitly prohibits wind and solar generation from providing frequency regulation, spinning reserves and supplemental reserves — one of the 21 case studies AEE reviewed in a May *report* on real-world barriers to wholesale market participation by clean energy resources.

"It sounds like a small thing, but if you're undercutting that, it can put financing for projects at risk," Reed said.

"We've had members that say, 'We'd love to participate in these markets, but we can't or are not going to because we don't know what the rules will be.' ... It's regulatory uncertainty that harms investment."

— Advanced Energy Economy Director Dylan Reed

Dennis also pointed to emerging proposals that could create barriers to participation, such as PJM's proposal as part of its Order 841 compliance filing that storage resources meet a minimum 10-hour discharge requirement to participate in its capacity market. Dennis said the requirement is based on an outdated measure used for pumped hydropower when it was the dominant storage resource. Recent analysis funded by the Energy Storage Association and Natural Resources Defense Council also criticized the plan. (See *Study Challenges PJM Energy Storage Rule*.)

"You can get a lot of capacity value out of two or four hours of discharge during that peak day. It would unfairly devalue that resource," Dennis said.

| EDF Renewables

No Risk to Cooperative Federalism

For wholesale markets to foster true competition on a technology-neutral basis, all resources should be allowed to compete on price and performance, AEE argues.

"One of the things we point out is that the markets are designed for large resources to provide lots of a product, but in the future, you're going to have collections of smaller resources providing smaller but high-performing chunks of services," Dennis said.

Reed added that such a grid transformation is dependent on a change in RTO market structures.

"That's when we're going to see a shift," Reed said. "We've created these rules for all these existing resources, but the resources are changing."

Dennis said good participation frameworks will give RTOs visibility into DER behavior and generation. He also stressed that no one is expecting perfection in early participation plans.

"There will certainly be a learning curve. I don't want to be too hard on the RTOs," Dennis said. But he is adamant that resources on the distribution system will be useful in providing wholesale services.

"It's going to certainly require coordination between state and wholesale operators. FERC can play a role in ensuring that the RTOs set up frameworks for that communication and coordination," he said.

Dennis also said distribution utilities can ask FERC to approve tariffs that allow them to recover any verifiable costs they incur from DERs participating in the wholesale markets.

"It's not an insurmountable barrier," he said, adding that FERC has already taken this

FERC/Federal News

approach with regard to distributed storage, adopting a brand of "cooperative federalism" that ensures greater utilization of those resources.

"I do worry that we're hearing some utilities claim that FERC setting up this framework is somehow destructive to cooperative federalism," Dennis said. "FERC has long respected state authority when it comes to wholesale participation by resources connected to distribution, and it continued to do that with storage."

Dennis noted that, under their retail ratemaking authority, states can restrict DERs participating in retail programs from also participating in wholesale markets, which would still provide DER owners a choice of where to participate. He expects that as states gain experience with DERs, they will see the benefit in allowing wholesale DER transactions.

Despite that vision, Dennis expects the distribution system will still fundamentally serve the purpose of delivering energy to customers and not become like federally regulated transmission.

"We don't think we're going to see so many distributed resources participating at wholesale that it swamps the distribution system and creates a situation where [distribution and transmission] perform the same function," he said.

In the Meantime

AEE says RTOs can take effective steps now while they wait on a FERC order, particularly in alleviating the need for DERs to undertake separate processes to interconnect with both the distribution and transmission systems.

Dennis praised PJM's examination into how it can streamline its interconnection process for distributed resources and NYISO's pre-emptive FERC filing to integrate DERs. AEE, however, did *take issue* with parts of the proposal, including proposed metering practices, buyer-side mitigation measures, a capacity value derate provision and a strict, six-second telemetry requirement (ER19-2276).

"I certainly appreciate that New York has gone ahead with something knowing that it's needed, particularly in response to New York state policy," Dennis said.

The AEE leaders say they will be pleased if FERC's final DER rules come close to Order 841.

"I think it will look a lot like Order 841," Dennis predicted. "We're hoping for a rule that allows distributed energy resources to provide all the services that they're technically capable of providing."

AEE says that while not perfect, RTO compliance plans for storage resources are thorough and well thought out. "All of them have taken the potential of energy storage very seriously," Dennis said.

He also expects the RTOs' compliance with a DER rule will be as varied as their responses to Order 841. Importantly, he said, RTOs will begin that work under a FERC deadline and with commission guidance on a workable framework for participation.

"They'll comply in their own unique way, but we'll have markets thinking about how they can include these DERs." ■

CAISO/West News

Bankruptcy Judge Questions PG&E Exec Compensation

Utility Posts Massive Q2 Loss as Wildfire Costs Mount

By Michael Brooks

The judge overseeing PG&E Corp.'s Chapter 11 bankruptcy questioned the utility's attorney last week over a proposed compensation package that includes about $11 million in performance-based bonuses for 12 executives.

At a hearing in San Francisco on Friday, Judge Dennis Montali, of the U.S. Bankruptcy Court for the Northern District of California, said he took issue with the language included in a PG&E court filing supporting its key employee incentive program (KEIP), filed with the U.S. Securities and Exchange Commission in late June.

The utility *told* the court its board of directors' compensation committee had "determined that the KEIP was necessary to appropriately incentivize and align the KEIP participants' goals and performance with those of the [company] and ... to provide the KEIP participants with the opportunity to achieve a market rate of compensation, but only if the KEIP performance goals are achieved."

Montali told PG&E attorney Stephen Karotkin that he had a problem with the phrase "appropriately incentivize," recalling that the utility's equipment was responsible for some of the worst wildfires in the history of the state.

"If they're not incentivized enough, they ought to find another job, frankly," the judge said.

Karotkin defended the bonuses, saying they would only be paid if the executives met certain targets. He assured the judge that they were dedicated to safety and regaining state residents' trust.

Montali also said he found it "troublesome" that the utility paid its new CEO, former Tennessee Valley Authority CEO Bill Johnson, a $3 million signing bonus without disclosing it to the court. Although the company disclosed the payment in an SEC filing and it was reported on in the *press*, it was paid before the company filed the KEIP with the court, which appeared to perturb the judge.

After a long back-and-forth with an attorney from the U.S. Trustee Program, who ultimately said he did not find the payment improper, Montali decided against ordering Johnson to disgorge the payment, though he scolded PG&E for being "too clever by half."

> **"If they're not incentivized enough, they ought to find another job, frankly."**
>
> — Judge Dennis Montali

CPUC 'Protocol' Talks Fail

Friday's hearing was set to discuss the results of negotiations between the California Public Utilities Commission and several ad hoc groups of bondholders, insurers and wildfire claimants that have asked Montali to terminate PG&E's exclusivity period — the time it has to offer a reorganization plan without the judge having to weigh competing proposals. The other stakeholders want the court to consider their own bankruptcy plans.

PUC attorney Alan Kornberg last month persuaded Montali to give the commission, Gov. Gavin Newsom's office and the groups time to work out a "protocol" — a process and timeline for the commission to consider all the competing plans and file one with the judge. Kornberg said the effort could expedite the process by eliminating the need for Montali to review several plans.

Under Assembly Bill 1054, passed last month, the PUC must approve a bankruptcy plan by June 30, 2020, for PG&E to be able to access a $21 billion fund to pay wildfire claims. (See *California PUC Jumps into PG&E Bankruptcy Fray*.)

But on Friday, Kornberg reported that talks had broken down, with the groups apparently insisting that PG&E play no role in selecting a restructuring plan. Montali directed Kornberg and the several attorneys representing the other parties to the discussions not to give him details of the talks so as not to prejudice himself before he rules on the groups' motions to terminate exclusivity on Tuesday.

Kornberg did say that several parties had told him they were confident the legislature would extend the June 30 deadline. An attorney for Newsom's office called banking on that "an unintelligent move."

Montali asked Kornberg if the PUC could begin to work on its own approval process simultaneously with the court. Kornberg said the commission needed a court-approved plan to consider; otherwise, it could waste time and resources considering a plan that might not ultimately be approved.

Earnings

The hearing came after PG&E reported earlier that day that it had lost $2.55 billion ($4.83/share) in the second quarter. The company posted a loss of $983 million ($1.91/share) for the second quarter last year.

The loss included a $3.9 billion pre-tax charge for estimated third-party claims related to the 2017 Northern California wildfires and the 2018 Camp Fire. The company has lost about $2.4 billion this year; it posted a profit of $136 million ($0.25/share) for the first quarter.

Total revenue for the second quarter was down about 7%, from about $4.2 billion in 2018 to about $3.9 billion this year.

"Items impacting comparability for the quarter also include enhanced and accelerated electric asset inspection costs; clean-up and repair costs related to the 2018 Camp Fire; legal and other costs related to the 2017 Northern California wildfires and the 2018 Camp Fire; and financing, legal and other costs related to PG&E Corp.'s and Pacific Gas and Electric Co.'s reorganization cases under Chapter 11 of the U.S. Bankruptcy Code," the company said in a *statement*.

"Our primary focus areas are to further reduce the risk of wildfires in the communities we serve, to improve our safety and operational performance across the board, and to move expeditiously through the Chapter 11 process, which includes paying wildfire victims fairly and as soon as possible," Johnson said. "We recognize we are operating from a deficit when it comes to public trust, and to regain that trust, we must sustain excellent operational performance day after day, month after month, year after year." ■

Cooperation, Forecasting Key to Calif. Climate Challenges

Continued from page 1

analysis lab, explained that while much of the science behind wildfires is well understood, there are still a lot of "known unknowns," including how to fit California's recent large outbreaks of tree mortality into existing wildfire models to understand how "large, dead trees" affect wildfire behavior.

"We also know that our existing fire weather forecasts underestimate really severe or extreme wildfire events," he said. "Part of that is due to the scaling; part of that is due to the technology; part of that is due to the way we have our measurements built. We know we need to deal with that."

Saah said that current wildfire models do not forecast "a long-term trajectory of where we're going" and therefore fail to provide investor-owned utilities a roadmap that can inform their long-term planning.

"And all this is really needed by not only the IOUs to be able to predict these overall impacts to the way they operate their systems, but it's also needed by the taxpayer, the resident, the environment that we all have here in California," he said.

But Saah said development of new models is not enough: Industry stakeholders must incorporate them into scenario planning.

"Our state is changing. We have this whole wildland-urban interface that we need to think of, and that interface is changing, and where it's locating, it's [also] growing. And the way fire behavior moves through those communities — again, it's one of these places that we need to do better in."

To address that shortcoming and others, SIG is developing a three-pronged approach to wildfire planning.

The first part seeks to improve the situational awareness of extreme fire weather and tree mortality through "optimal configuration" of weather stations, examination of past extreme events, and analysis and mapping of tree mortality. The second part incorporates new scientific findings into near-term forecasts and long-term projections, while the third would create models that provide IOUs and other stakeholders with "actionable information" applicable to the time scales contained in those forecasts and projections.

Once those models are developed, Saah said their "source code" should be opened to the industry and wider public for critical examination.

"The more critics that we can get hammering away at it, the more learning we can actually get," he said.

Shifting Paradigms

California regulators have lauded San Diego Gas & Electric as a model for how the state's utilities can prevent wildfires in their service areas. (See *Calif. Regulators to Scrutinize De-energization*.) The utility credits its extensive weather monitoring system for the fact that its service territory hasn't experienced a major fire since 2007.

Brian D'Agostino, SDG&E's director of fire science and climate adaptation, said the utility isn't resting on its laurels. The utility is instead

Rim Fire | *USDA*

CAISO/West News

effectively rebuilding what was once the world's largest utility weather network. (The state's larger IOUs are now poised to surpass SDG&E's network as part of their wildfire plans.)

SDG&E plans to expand its network from 177 weather stations to 225 by the end of next year, with a focus on new installations along the wildland-urban interface that can provide data every 10 seconds to support emergency operations. The new stations will be positioned to perform a new function: minimizing the customer impact of power safety power shutoffs (PSPS) undertaken during periods of high fire danger.

"It's not just where we find the windiest areas or where this weather information will best improve our fire models, but a big part of it is we have to work with the electric engineers on the system for PSPS events," D'Agostino said.

SDG&E has also synchronized its fire behavior models with census and building data to identify the highest-risk areas with respect to population density.

D'Agostino also pointed out that SDG&E is also incorporating its database of 455,000 trees into its fire behavior modeling systems in order to identify every tree that has the potential to hit a power line. The utility is also simulating more than 10 million fires every day to determine the risks to its entire system.

"There is a lot of room for improvement, as we've heard [from Saah], so we're looking closely to continue to collaborate with the ongoing statewide projects," D'Agostino said, expressing excitement at the "open source" nature of the effort.

> **"If you look at the way our scientific infrastructure's been built for a long time, it's been built around competitive science. I think that era's over. I think we really need to get into collaborative science."**
>
> — David Saah, Spatial Informatics Group

Speaking during a Q&A session at the end of the workshop, CEC Commissioner Andrew McAllister noted his agency must perform 10-year forecasts to help guide development of the state's energy system. Pointing out that the CEC increasingly relies on scenario modeling as the effects of climate change "happen more quickly than anticipated," he asked D'Agostino how SDG&E is considering higher-than-expected temperature increases as it maps out its own long-term transmission and distribution investments.

D'Agostino said he couldn't directly speak to the utility's funding priorities, but that as the head of meteorology, he could point to what his department is doing differently, including adopting an approach of focusing on only the most recent years' weather data — rather than a long historical time horizon — to predict future temperatures and weather patterns.

Another change had to do with load forecasting. D'Agostino explained that SDG&E's peak loads have historically occurred during periods when the hot, dry Santa Ana winds blow off the desert to the east of Southern California's population centers. But a new pattern has emerged over the last 10 years in which hot, humid air masses coming from the south are accompanied by unusually warm water currents.

"Last year, we didn't set a new [peak] load, but our water temperature off San Diego was supposed to be about 68, 69 degrees, and it was close to 80 for almost three weeks in a row, which kept our nighttime temperatures [from] even coming down to what our normal daytime high was," D'Agostino said. "And that went on for weeks last summer and caused a lot of challenges in operating the electric system. So, we're seeing a new type of load."

Reiterating the point about the speed at which climate change is occurring, CEC Vice Chair Janea Scott asked, "What kinds of things do we need to do in this space to make sure that we're doing our best to keep up or even get out ahead of things?"

"We're entering into this no-analog scenario," Saah responded. "We have no idea how this thing's going to work. If you look at the way our scientific infrastructure's been built for a long time, it's been built around competitive science. I think that era's over. I think we really need to get into collaborative science. And the place where we learn from each other as quickly as we can, we [will] change things as quickly as we can."

D'Agostino said he seconded that view: "Our ability to work with each other at this point is really going to help us move faster." ■

ERCOT News

ERCOT Sets New Demand Mark, Smashes '18 Record

By Tom Kleckner


| Apex Clean Energy

After days of near misses, the ERCOT grid registered a new all-time demand peak of 74.5 GW on Monday as Texas continued to bake in heat extreme even for the Lone Star State.

Monday's peak, coming during the interval ending at 5 p.m., smashed the old mark of 73.5 GW, set in July 2018. ERCOT initially broke the record during the hour ending at 4 p.m., when load hit 74.2 GW, almost 700 MW above the 2018 mark.

As the temperatures have soared, so have energy prices. Systemwide settlement prices hit $6,537.45/MWh for the 15-minute interval ending at 3 p.m. on Monday, after first hitting quadruple figures during the 2 p.m. interval.

ERCOT has recorded eight of its 12 highest peaks since Wednesday. Earlier this month, the grid operator set records for August demand (about 73.1 GW) and weekend demand (71.6 GW and 71.9 GW on Saturday and Sunday, respectively).

A ridge of high pressure settled over Texas last week, funneling hot air from the Western U.S. into the southern Great Plains. The National Weather Service has issued several heat advisories during that time, the latest for all Southeast Texas on Monday calling for heat indexes between 108 and 113 degrees Fahrenheit. Houston hit 100 F for the first time this year on Thursday, and Bayou City, Dallas and San Antonio are expected to stay above 100 into this Wednesday.

ERCOT has been able to meet demand without resorting to the emergency measures it warned it might have to take. The grid operator has an 8.6% reserve margin and 78.9 GW of available capacity. (See *ERCOT: More Capacity, but Emergency Ops Still Expected*.)

"ERCOT expects to have adequate generation to serve customers during this hot spell," spokesperson Leslie Sopko said last week. The grid operator survived Monday's high demand with about 3 GW of operating reserves.

ERCOT has issued heat warnings for the Dallas area that prevent utilities from cutting off power for delinquent bills. Houston utility Reliant Energy asked customers to reduce their electricity usage from 2 to 6 p.m. on both Monday and Tuesday.

Last week, real-time prices peaked systemwide at more than $2,400/MWh on Aug. 5.

Day-ahead power prices for Monday were above $220/MWh in the North hub Friday, the highest since reaching $300/MWh the day before the record peak last July. The hub's next-day prices were at $38.50/MWh on Aug. 5. ■

CenterPoint Q2 Earnings Beat Expectations

CenterPoint Energy on Wednesday beat both analysts' expectations and its performance a year ago by *reporting* second-quarter earnings of $165 million ($0.33/share).


| CenterPoint Energy

The results exceeded Zacks Investment Research's projection of 31 cents/share and the second quarter of 2018, when the company lost $75 million ($0.17/share). Last year's loss included a pre-tax write down of $242 million to reflect the company's investment in Time Warner, which has since been acquired by AT&T.

"It was a solid second quarter," CEO Scott Prochazka told analysts during a Wednesday earnings call.

The Houston-based company said its performance was driven by its utility operations and cash contributions from non-utility businesses such as Enable Midstream Partners, a joint venture with OGE Energy and ArcLight Capital Partners. The pipeline company reported $74 million of equity income for the quarter, a $16 million improvement over last year.

Prochazka said CenterPoint no longer intends to sell common units of Midstream, as "much has changed since we first considered the sale." He said Midstream, which has contributed $1.7 billion in cash distributions to CenterPoint since 2013, "now reports a smaller percentage of our earnings" with the closing of the $6 billion Vectren merger in February.

Vectren contributed $25 million in operating income.

CenterPoint's stock opened at $28.85/share Wednesday morning but quickly dropped to $27.47. The stock recovered to close at $28.14, down 2.5%. ■

— Tom Kleckner

ERCOT News

Earnings Soaring, NRG Prepares for Tight ERCOT Supply

By Michael Kuser

NRG Energy's profits jumped sharply in the second quarter, boosted by a surge in earnings for the company's power generation division.

The rise was "driven primarily by higher wholesale power prices, offset by higher retail supply costs and mild weather," NRG CEO Mauricio Gutierrez said in a *call* with analysts on Wednesday.

The company *reported* second-quarter earnings of $189 million ($0.75/share), compared to $27 million in the same period last year.

NRG's generating arm earned $618 million for the quarter, up 145% from a year earlier, while losses from the retail division grew from $84 million to $280 million.

The company said that generation gains on hedge positions this year were partially offset by losses on retails hedges, "both driven by large movements in gas prices and ERCOT heat rates."

During the quarter, NRG launched its "capital-light" strategy by signing approximately 1.3 GW of solar power purchase agreements at an average length of 10 years, complementing its generation portfolio. The company also highlighted that its 385-MW combined cycle Gregory plant in Corpus Christi returned to service in June.

Gutierrez noted NRG has spent $1.25 billion so far this year on a share buyback program and announced plans to spend $250 million more by year-end.

"We will address our plans for the remaining $259 million of 2019 excess cash, as we usually do, on the third-quarter earnings call," Gutierrez said, noting that the company is reserving up to a $124 million in capital for the *Petra Nova* project. The coal-fired power plant captures carbon dioxide from one of the eight units at the 3.65-GW WA Parish Generating Station southwest of Houston, which is then injected into mature oilfields to release more oil.

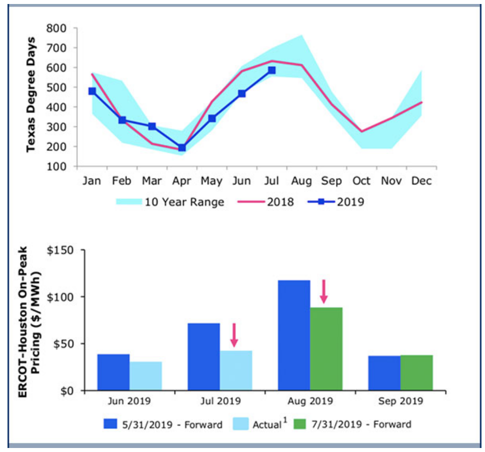
In May, NRG agreed to spend $325 million for Stream Energy's retail electricity and natural gas business, increasing its retail portfolio by approximately 450,000 customers. The acquisition closed on Aug. 1.

Markets Update

Gutierrez said NRG expects ERCOT's supply-demand balance to remain tight, given strong load growth, previous generator retirements and a lack of new builds. He pointed out that ERCOT's own projections for its future supply margins rely on its semi-annual Capacity, Demand and Reserves report, which has typically been a "poor indicator of what actually gets built in the current year."

He noted the report includes 1.7 GW of natural gas-fired generation that has been delayed an average of five years "with no signs of moving forward" and 1.4 GW of thermal generation already set to retire, while little more than half the 7 GW of solar projects listed have posted the financial security needed to interconnect to the grid.

"ERCOT needs a lot of generation … needs a lot of investment," Gutierrez said. "And even the numbers that we're providing you are only sufficient to maintain the current load reserve margin that we have.



NRG's ERCOT data show mild weather impacting power prices. | *NRG Energy*

"Obviously, the implication of that is we expect the ERCOT market to continue to be robust over the foreseeable future but, more importantly, to be pretty volatile," he said. "This price environment should prove difficult for pure retailers or generators that will be exposed to swings in the market."

Gutierrez also referred to a recent FERC order directing PJM to delay its August capacity auction. (See *FERC Halts PJM Capacity Auction*.)

"While we're hopeful a final order will be issued by the end of the year, the timeline for FERC action remains uncertain," Gutierrez said. "We continue to view a strong [minimum offer price rule] as the simplest and most cost-effective way to reduce the harmful impact of subsidies on the capacity market."

Call transcript courtesy of Seeking Alpha. ■

ERCOT News

ERCOT, WMS Collaborate on Price Corrections

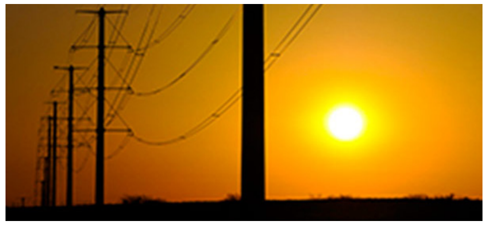
By Tom Kleckner

ERCOT staff have laid out a plan to work with stakeholders in addressing a May pricing event that has led to a complaint filed with Texas regulators against the grid operator.

Kenan Ögelman, ERCOT's vice president of commercial operations, met with the Wholesale Market Subcommittee on Wednesday and proposed three issues for further discussion with market participants, including potential changes to the grid operator's price-correction methodology; adding filters, requirements or different standards to the external telemetry coming into ERCOT; and improving the communications structure around price corrections.

Ögelman said staff would return to the WMS in September with an issues list. He said he expects "more topics than any solutions."

"We'd like to give a high-level presentation and see if you have any other issues," Ögelman said. "I think it's important everyone see all the issues and where they're going so we can get a solution."



| *Lone Star Transmission*

On May 30, prices briefly reached the $9,000/MWh maximum when the security-constrained economic dispatch system received bad telemetry data from Calpine. Staff quickly corrected the data, but they have refused to correct the prices because the data were external.

"Incorrect telemetry coming from outside ERCOT is not something we run corrections for," Ögelman told the grid operator's Board of Directors in June.

Aspire Commodities, an energy broker, has filed a complaint with the Public Utility Commission of Texas asking that generators refund the market $18 million (*49673*). (See *ERCOT Asks PUC to Dismiss Trader's Complaint*.)

Morgan Stanley's Clayton Greer, who has complimented ERCOT on its quick response to the pricing error, urged quick decisions in the future.

"You let us know you were not going to reprice that day. The market understands once you do that, it's final," he said. "If you could find a way to put into words what you did [on May 30] into the protocols, that would be optimal."

"We want prices to reflect the fundamentals of the market," Reliant Energy Retail Services' Bill Barnes said.

Luminant Generation's Ian Haley indicated his company preferred to see bad telemetry rejected.

"We don't think ERCOT should be in the business of determining what is and what isn't correct," he said. ■

Texas PUC Briefs

Commissioners Need More Information on Munis' Appeal

The Texas Public Utility Commission last week asked for more information on eight small municipal utilities' appeal of ERCOT's definition of transmission operator (TO) (*48366*).

The PUC *directed* the State Office of Administrative Hearings to return ERCOT's order to the commission so that it could solicit feedback from stakeholders in a docket. Given legal briefs and other information, the commission would then be able to dismiss the ruling and open a rulemaking or project.

The Small Public Power Group (SPPG) — composed of utilities for the cities of Bartlett, Bridgeport, Farmersville, Goldsmith, Hearne, Robstown, Sanger and Seymour — is appealing the ERCOT Board of Directors' 2018 rejection of a proposed change to the Nodal Operating Guide (*NOGRR149*).

"We will, of course, provide comments on the questions the commission [poses] and look forward to the discussion that follows," Clark Hill Strasburger's Tom Anson, legal counsel for SPPG, told *RTO Insider*.

The NOG requires every transmission or distribution service provider in ERCOT to either register as a TO or designate a representative on its behalf. The TOs communicate with ERCOT during emergency events and the management of load-shed activities, among other responsibilities.

NOGRR149 would have exempted municipal distribution service providers without transmission or generation facilities from having to procure designated TO services from a third-party provider if their annual peak load is less than 25 MW. SPPG developed the revision request in 2015 to settle the noncompliant status of six municipally owned utilities with loads of 9 to 21 MW. Goldsmith and Bartlett joined the proceeding later. The Technical Advisory Committee and its Reliability and Operations Subcommittee also rejected the change. (See "Small Public Power Group's Appeal Again Meets Defeat," *ERCOT Board of Directors Briefs: April 10, 2018*.)

Transmission and distribution operators AEP Texas and Oncor are the only two intervenors.

"When I looked at the docket and who intervened, I was shocked there were only the two intervenors," PUC Chair DeAnn Walker said during the commission's open meeting Thursday. "This has been a hard-fought issue at ERCOT where a lot of people put stakes in the ground, and they're not putting them here, and I don't understand why."

"This commission can operate better in a project when we can hear from all the stakeholders and ask them questions," Commissioner Arthur D'Andrea said during the commission's debate over how to proceed.

The SPPG *says* its proposal would conform operating guides to the "existing factual situation." None of the SPPG members is or ever has been in the ERCOT load-shed table, the group said, and the revision would not "in any way, affect the reliability of the ERCOT system."

"Several SPPG members are so small, they are physically limited in their ability to comply with the relevant ERCOT requirements," according to the group's filing.

ERCOT has asked that the PUC deny the appeal because SPPG "has not demonstrated any legal basis for reversing the [board's] decision to reject NOGRR149" and because it has not alleged "any credible violation of law."

Walker said she wanted to ensure the

Continued on page 32

ISO-NE News

Connecticut Activists Protest Gas-fired Plant

650-MW Killingly Energy Center not Needed, Environmentalists Say

By Michael Kuser

Environmental activists marched Wednesday in front of DEEP headquarters to protest the approval of a 650-MW power plant in Killingly, Conn. | © *RTO Insider*

HARTFORD, Conn. — About 40 environmental activists marched Wednesday in front of the headquarters of Connecticut's Department of Energy and Environmental Protection to protest state regulators' recent approval of a new gas-fired power plant in the town of Killingly.

The Connecticut Siting Council on June 6 *approved* construction of the 650-MW Killingly Energy Center by Florida-based *developer* NTE Energy, permitting the plant to emit up to 2.2 million tons of carbon dioxide each year.

The organizers included *Connecticut Fund for the Environment*, *Not Another Power Plant*, the state *chapter* of the Sierra Club and *Wyndham Land Trust*.

Martha Klein, Sierra Club | © *RTO Insider*

Sierra Club volunteer Martha Klein led the protesters in a chant on the steps of DEEP headquarters: "Hey, hey, ho, ho, Katie Dykes has got to go!" — referring to the DEEP commissioner.

"I've got a simple one-word answer for why Connecticut keeps expanding fracked methane despite knowing that it's destroying our climate: It's 'corruption,'" Klein said. "It's equal opportunity corruption, for we've had both a Republican governor [John Rowland] and a Democrat mayor [Hartford's Eddie Perez] go to jail." Neither politician was convicted of illegal activity related to the energy sector.

Klein told *RTO Insider* that "when the state approves new power plants run on fracked gas or oil, that's going to exacerbate climate change."

Ann Gadwah, chair of the state's Sierra Club chapter, said, "This plant is totally unneeded. New England doesn't need the power, and Connecticut doesn't need the power."

Gadwah said regulators seem to have forgotten that the state legislature passed a law requiring DEEP to monitor air quality in the eastern part of the state after New York approved construction of the 1,100-MW natural gas-fired Cricket Valley Energy Center, which is slated to go online next year and the emissions of which would generally blow into Connecticut from its site just west of the state line.

RTO Scapegoat

James Albis, a senior adviser to Dykes, spoke to activists and reporters at the protest and handed out flyers with questions and answers on Killingly.

On why the plant is being built, DEEP said, "It was procured through the regional ISO New England capacity market auction to meet regional reliability needs. It will help address reliability needs in the winter because of its dual-fuel capability, allowing it to run on ultra-low-sulfur diesel during peak times when natural gas is constrained, which is a cleaner alternative to other baseload peaking generators."

In response to the question of who will pay for the plant, the department said the state "does not have any contractual obligations with Killingly. The plant cleared in the regional [ISO-NE] market that Connecticut participates in, but NTE (the developer) bears the risk of participating in the market and the potential for stranded costs as Connecticut moves to a zero-carbon future."

Melinda Fields came to protest from Hampton, a few miles west of Killingly.

"I protested the Siting Council meeting too," Fields said. "It seemed like they only wanted to help the company get what it wanted; like, 'what can the state do for you?'"

The area's state senator, Mae Flexer, submitted testimony stating that Connecticut Economic Resource Center data indicate that Killingly would become the second-largest power generation town in the state if the plant is built, behind only Waterford, site of the Millstone nuclear plant.

"This would be an enormous burden to place on the people and environment of Killingly," Flexer said. "To require so much of the state's electricity to be generated here and — along with it — to concentrate such a large percentage of the state's pollutants and emissions from power generation in this town is grossly unfair."

Independent activist Cher Kapelner-Champ | © *RTO Insider*

Veteran activist Cher Kapelner-Champ said she had been among 1,200 people arrested in 1977 for protesting the construction of the Seabrook nuclear plant in New Hampshire.

"They built Seabrook anyway, so why do I keep protesting?" she said. "As a great Hebrew scholar once said, we all just bring our one teaspoon of compassion — and you never know when the tipping point will come." ■

ISO-NE News

Lacking Quorum, FERC OKs ISO-NE Energy Security Plan

Continued from page 1

challenges,” ISO-NE spokeswoman Marcia Blomberg said in a statement. (See “Assessing ESI Risk Premiums,” *NEPOOL Markets Committee Briefs: July 30, 2019*.)

The RTO’s fuel security program, filed in March, is an interim plan for its 14th and 15th Forward Capacity Auctions, covering the capacity commitment periods of 2023/24 and 2024/25. The commission on May 8 said the filing was deficient, and the RTO submitted its *response* on June 6.

FERC’s reference to a lack of quorum initially had FERC watchers scratching their heads because the commission will still have three commissioners even after the departure of Democrat Cheryl LaFleur. (See *FERC Could Face Months with 3 Commissioners*.)

Chatterjee, Glick Split

Section 205 of the Federal Power Act requires each commissioner to explain their views with respect to the Chapter 2B changes. On Thursday, the commissioners filed their comments, with LaFleur and Commissioner Bernard McNamee indicating they had not participated.

Chairman Neil Chatterjee said he would have approved ISO-NE’s filing, saying it “provides reasonable interim compensation, which can serve as a bridge to development of the longer-term market solution.”

“It is well settled that the entity filing a proposal need only demonstrate that the proposed revisions are just and reasonable, not that the proposal is the most just and reasonable proposal,” he said. “While some parties argue that ISO New England’s previous winter reliability programs are less expensive and may be more effective than the proposal in this proceeding, those programs are not the subject of this proceeding and are not before the commission.”

Chatterjee said the program “also aims to ameliorate the misaligned incentives issue” that prior programs did not address.

But Commissioner Richard Glick said he would have opposed the program as “patently unjust and unreasonable.”

“The program will cost New England consumers as much as $300 million without any evidence to suggest that it will actually improve the region’s fuel security or that any improvement is likely to be worth the cost. Indeed, the program goes so far as to hand out substantial payments to nuclear, coal and hydropower generators with no indication that these payments will change their behavior in the slightest,” Glick wrote. “That is a windfall, not a just and reasonable rate.”

“The program goes so far as to hand out substantial payments to nuclear, coal and hydropower generators with no indication that these payments will change their behavior in the slightest That is a windfall, not a just and reasonable rate.”

— FERC Commissioner Richard Glick

Technical Conference

At a July 15 technical conference, New England regulators and stakeholders told FERC that ISO-NE’s fuel security proposal could increase costs without solving the region’s winter supply concerns and urged the commission to postpone the RTO’s Oct. 15 filing deadline and require it to provide more analysis before drafting Tariff changes. (See *FERC Staff Hear Doubts on ISO-NE Fuel Security Plan*.)

Jeff Bentz, the New England States Committee on Electricity’s director of analysis, testified the schedule could be delayed by six months without impacting the proposed implementation.

New England Power Pool Chair Nancy Chafetz, of Customized Energy Solutions, asked the commission to “keep an open mind” on the proposals. Although NEPOOL has the “jump ball” right to propose an alternative to the RTO’s proposal, Chafetz said the stakeholder body wouldn’t have an official position until it votes in October.

Day Pitney attorney Pat Gerity said in a notice to NEPOOL members that “while NEPOOL intervened in the Chapter 2B proceeding, it took no substantive position and, absent express direction from the [Participants] Committee, will not challenge the Chapter 2B Notice.”

Gerity noted FERC has previously been unable to act on an ISO-NE filing, but Congress has since stepped in to allow such non-action by the commission to be challenged on rehearing and appeal. “Specifically, the ‘Fair Ratepayer Accountability, Transparency, and Efficiency Standards Act’ was included as part of ‘*America’s Water Infrastructure Act of 2018*’ (Oct. 23, 2018), the result of which will be to treat the Chapter 2B notice for purposes of rehearing to be an order issued by the FERC accepting the changes,” Gerity said, adding that any request for rehearing of the Chapter 2B notice will be due by Sept. 4.

In a related matter, the New England Power Generators Association asked the commission Aug. 6 to reverse its decision to require generators needed for fuel security to offer at zero in FCA 14. It asked the commission to issue a rehearing order by Sept. 26, “before key deadlines lapse” for the auction (*ER18-2364-001 and EL18-182-002*).

Reaction

Sierra Club spokesman Brian Willis issued a statement calling FERC’s action “odd and infuriating.”

“Back in May, FERC gave ISO-NE a laundry list of what was wrong with its controversial market proposal. … The inventoried energy program was broadly opposed by New England stakeholders, who presented evidence that ISO-NE’s program was discriminatory and unnecessary. ISO-NE refused to provide any of the additional information requested by FERC. In light of this, it appeared likely FERC would reject the inventoried energy program outright or order ISO-NE to rewrite its rules based on new principles, legal precedent or with greater consideration for costs to ratepayers.”

Former FERC attorney Jeff Dennis, now general counsel for Advanced Energy Economy, had a different perspective. “Some version of the inventoried energy program has been approved every winter for MANY years now,” he tweeted. “No one likes it, FERC always wrings its hands when it approves it, but it always does.” ■

ISO-NE News

ISO-NE Planning Advisory Committee Briefs

Boston 2028 Update to Include NECEC, Revolution Wind

ISO-NE planners will update the base cases for the Boston 2028 Needs Assessment to include Central Maine Power's New England Clean Energy Connect (*NECEC*) and the Revolution and Vineyard offshore wind projects, senior engineer for transmission planning Pradip Vijayan *told* the Planning Advisory Committee on Thursday.

NECEC will be modeled as a 1,090-MW injection at the Larrabee Road 345-kV line in Maine, while Revolution Wind will be modeled as a 120-MW injection at the Davisville 115-kV line in Rhode Island (20% of the contact value of 600 MW). Vineyard Wind is also modeled at 20% of its contract value, or 160 MW. Revolution Wind is being included even though its impact on the Boston study area is not considered significant, Vijayan said.

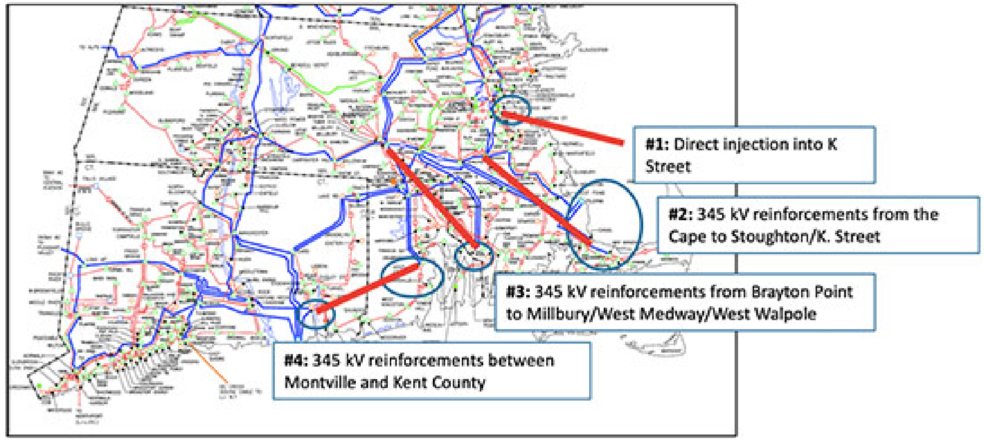
The update also will reflect Forward Capacity Auction 14 retirement and permanent delist bids and FCA 13 retirement and delist bids outside Boston, resources that were assumed to be available for dispatch in the previous assessment. Additional active demand capacity resources will reduce net load by 55 MW.

The update will be restricted to an evaluation of 2028 peak load conditions; the changes are not expected to impact assessments of minimum load, short circuits or the 2022 peak load.

The RTO plans to issue its first request for proposals for a competitively developed transmission solution under FERC Order 1000 in December to address the non-time-sensitive needs identified in the assessment: a reactive device to maintain the ability to restore downtown Boston's transmission system after Mystic Units 8 and 9 retire. (See *ISO-NE Refines Competitive Tx RFP Template*.)

ISO-NE planners want to maintain as much as possible of the current restoration plan, in which Mystic 8 and 9 are among the first units brought online to energize the Boston transmission system. The units help regulate system voltage during the energization of the cables. To replace them, the RTO will be seeking a dynamic reactive device capable of absorbing the charging associated with the cables, Vijayan said.

The device must be able to be re-energized remotely and adjust its voltage control set



Offshore wind additions above 7,000 MW may require additional injections or transmission reinforcements, according to preliminary ISO-NE economic studies. | *ISO-NE*

point remotely based on ISO-NE dispatch instructions. To meet NERC standard PRC-024-2 and ISO-NE's transient voltage criteria, it also will be required to stay connected on a low-voltage ride-through for between 0.15 and 10 seconds, depending on voltage. Required high-voltage ride-through will be 0.2 to one second.

The RTO has identified several potential locations for the device: Mystic 345-kV or 115-kV; North Cambridge 345-kV or 115-kV; Wakefield Junction 345-kV or 115-kV; Woburn 345-kV or 115-kV; and Tewksbury 345-kV.

ISO-NE is also working with Eversource Energy and National Grid to develop solutions to the time-sensitive high-voltage needs identified at minimum load levels in the Needs Assessment.

They have narrowed the potential solutions to a single 160-MVAR reactor at Golden Hills 345-kV or one 76-MVAR reactor at each location for one of the following combinations:

- Everett 115-kV and K Street 115-kV
- Everett 115-kV and Lexington 115-kV
- K Street 115-kV and Lexington 115-kV

Cost estimates and evaluations of the options will be discussed at September's PAC meeting, when a preferred alternative will be selected. The PAC will discuss the results of the Needs Assessment update in October.

Stakeholder comments on the PAC presentation should be submitted to *pacmatters@iso-ne.com* by Aug. 25. The RTO set the same deadline to be informed of projects that should be reflected in the assessment update because of state-sponsored solicitations.

RSP 19 Stakeholder Comment Review

ISO-NE's Director of Resource Adequacy and System Planning, Carissa Sedlacek, presented a review of stakeholder *comments* on the draft 2019 Regional System Plan (*RSP*).

Sedlacek went one by one through 83 comments, explaining why RTO staff did or did not accept suggested edits. Some comments were legalistic tweaks to the wording, such as deleting a reference to "regional regulators," as there is no such thing.

In several instances, the RTO preferred the phrases "energy constraint" to "fuel constraint," and "energy storage" rather than "battery storage."

"ISO-NE is trying to be more generic in the language, for the region has large pumped hydro facilities that are storage facilities," Sedlacek said.

Regarding a question on exactly what the RTO meant by "variable energy resources" (VERs), she said "the sentence states that 'VERs … are replacing nuclear, coal and oil resources…' which is true. The [RTO] is not stating that VERs are the same as gas-fired generation, just that VERS are variable."

Synapse Energy, commenting on behalf of the Maine Office of Public Advocate and the energy-buying consortium PowerOptions,

ISO-NE News

suggested ISO-NE add a mention to 1,381 MW of storage in a section that described the region's wind and large-scale PV resources and that it specify whether the storage is behind-the-meter, front-of-the-meter or both.

Sedlacek referred to the RTO's comment that it considers all behind-the-meter resources in its peak and energy forecasts. "However, we don't create a BTM energy storage forecast," she said.

David Ismay of the Conservation Law Foundation (CLF) wanted wording changed to reflect that "five of the six" New England states have climate change as a top priority. But Sedlacek said staff did not accept that suggestion because the RSP "is not intended to be a breakout of state policies."

CLF also recommended discussing "the connection to ISO-NE's fuel and energy security concerns, including capacity supply obligations granted to fuel-insecure plants at effectively their full nameplate capacity." CLF said it was "particularly relevant" given FCA 13's *clearing* of NTE Energy's Killingly Energy Center, a 650-MW natural gas generator planned in Killingly, Conn.

"We hear you; we see your comments. We're talking about energy security versus fuel security, and the integration of increasing amounts of renewable resources."

— Carissa Sedlacek, ISO-NE

"The RSP is not the place to have a discussion of matters in an open docket," Sedlacek said. "ISO-NE awaits responses from FERC on open dockets for FCA 13 and Mystic 8 and 9.

"We hear you; we see your comments. We're talking about energy security versus fuel security, and the integration of increasing amounts of renewable resources," she said.

2019 Economic Studies Detailed Assumptions

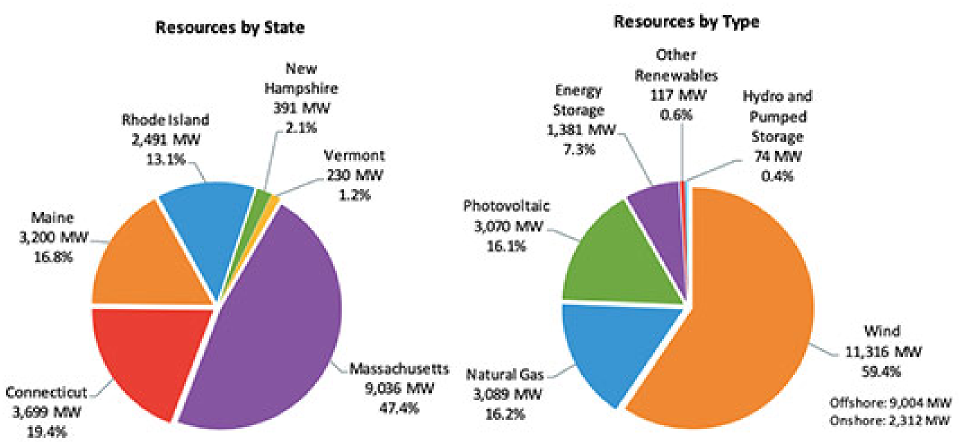
Stakeholders discussed the detailed assumptions for three 2019 economic studies, as presented by ISO-NE staffers Peter Wong and Patrick Boughan.

The RTO agreed to analyze scenarios and market impacts for the integration of up to 9,700 MW of offshore wind by 2035, similar to what was requested separately by the New England States Committee on Electricity and transmission developer Anbaric Development Partners. (See *ISO-NE Planning Advisory Committee Briefs: April 25, 2019*.)

The NESCOE scenarios will model five levels of offshore wind ranging from 1,000 to 7,000 MW, while the Anbaric scenarios will model three between 5,700 and 9,700 MW. They also will look at varying injection locations and several potential transmission expansions, most of them 345-kV reinforcements, Wong said.

In addition, planners will evaluate two potential transmission upgrades that would increase the operating limits of the Orrington South interface in Maine, as requested by RENEW Northeast.

In one scenario, planners will consider increases of 0 to 170 MW from the modified 2016 transfer limits provided by RENEW.



Resources active in the ISO-NE interconnection queue, by state and fuel type, as of April 1, 2019 (MW and %) | *ISO-NE*

ISO-NE News

VELCO's Berlin substation control building lacks space to accommodate needed improvements, communication equipment and ancillary systems. | *VELCO*

In the second scenario, they will evaluate increases of 100 to 825 MW. The analysis will be performed with and without the interfaces downstream of Orrington South being modeled at the projected 2025 transfer limits.

Based on the currently expected transmission system for 2030, the RTO anticipates it could add about 7,000 MW of offshore wind without additional major 345-kV reinforcements, though some reinforcement or expansion may still be needed, Wong said.

If more than 7,000 MW is added, the RTO sees the potential need for transmission reinforcements or new injections.

NESCOE counsel and analyst Ben D'Antonio asked how ISO-NE ranked the alternative transmission upgrades or reinforcements to accommodate offshore wind. Wong said that the RTO would discuss the issue and report back.

"If there's more reinforcements beyond 345-kV lines, we want to see that," D'Antonio said.

"We will be developing plans and high-level expansion costs associated with those needs," Wong said.

Theodore Paradise, counsel and senior vice president of transmission strategy at Anbaric, said, "When we get close, is it that 200 MW that really pushes it over [the transmission capacity limit]? … If we spread out these interconnection points so we don't overload, we're OK with that too."

"We will have to decide what modeling to use for best results," Wong said.

VELCO Berlin Substation Condition

Vermont Electric Power Co. (VELCO) engineer Hantz Presume *reported* on the dilapidated condition of the Berlin substation, which connects two 115-kV lines and one transformer.

Problems include obsolete relays, lack of protection for breaker or circuit switcher failures, lack of a back-up protection system, and lack of high-speed protection.

The control building lacks space to accommodate needed improvements, communication equipment and ancillary systems, Presume said, and its location does not meet National Fire Protection Agency (NFPA) requirements that it be more than 50 feet from any power transformer.

VELCO proposes replacing the control building and the protection and control (P&C) system, installing a breaker failure scheme and high-speed protection as the second scheme.

The New England Power Pool transmission facility portion of the costs is estimated at $5.9 million, and the non-PTF portion at $4.7 million, for a total project cost of $10.6 million (+/-10% accuracy and including 15% contingency).

Replacing the substation could cost up to seven times as much, Presume said.

Eversource 345-kV Structure Replacements

Eversource's John Case presented the company's *plans* to replace 1,483 345-kV structures at an estimated cost of $403.9 million (-25%/+50%).

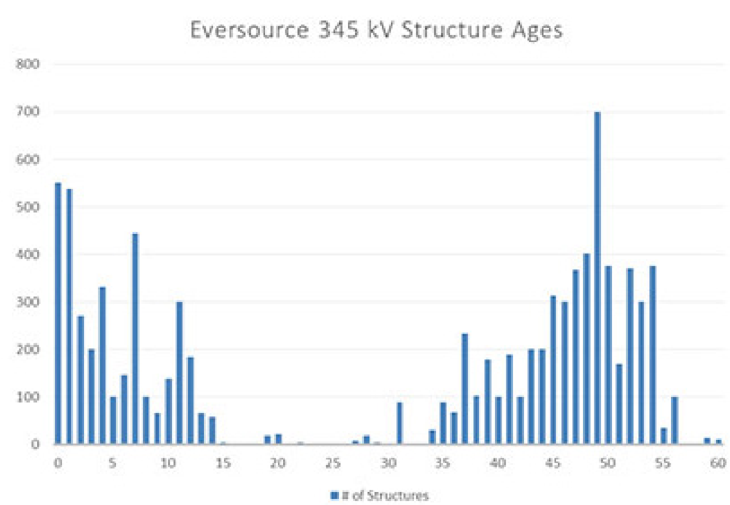
The replacements will be light-duty tubular steel poles that comply with current clearance and strength code requirements. Eversource anticipates completion of the work in 2021.

After this replacement program, any future 345-kV upgrades that require PAC approvals will be brought forth on a line-by-line basis, Case said.

The company is supplementing foot patrols with high-definition cameras on drones, which allows inspectors to see possible damage from all angles, he said.

"The use of drones is phenomenal at getting right in there to see what's going on; it's a great tool," Case said. ■

— Michael Kuser



Eversource has more than 9,000 345-kV structures in New England, most of them built in the 1960s and 1970s. | *Eversource Energy*

MISO News

MISO Finds Loss-of-load Risk in Fall, Winter Months

By Amanda Durish Cook

CARMEL, Ind. — For the first time, MISO has found a loss-of-load risk outside of summer months, and the RTO said it may be more evidence of the need for seasonal capacity supplies.

"We believe at least exploring a seasonal resource adequacy construct based on this is appropriate," MISO planning adviser Davey Lopez said at a Resource Adequacy Subcommittee meeting Wednesday.

However, Lopez said MISO will conduct more analyses, probably through the end of the year, before it says for sure whether it needs seasonal resource accreditation or a seasonal capacity auction.

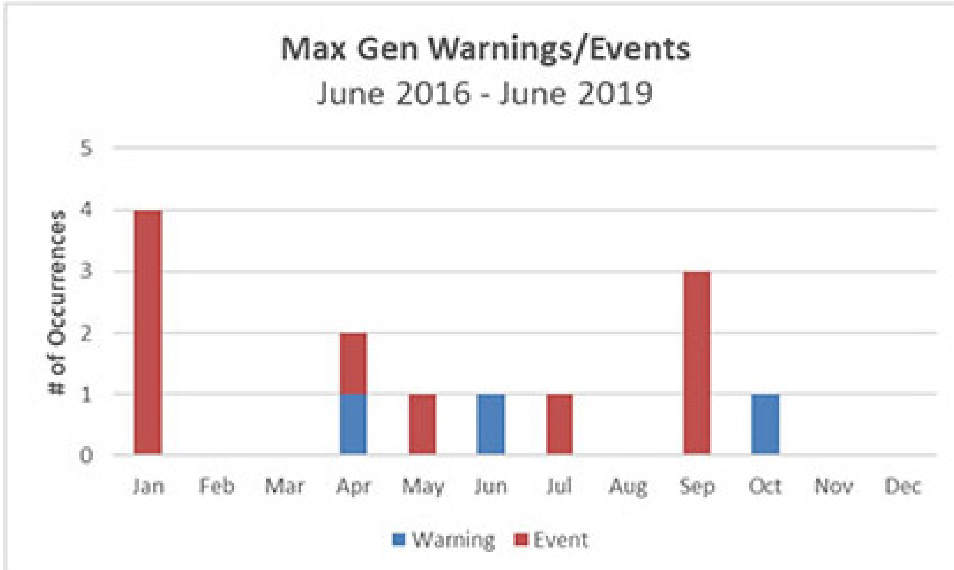
"We have done some analysis that shows material risk of loss of load outside of summer," Lopez said at the July Resource Adequacy Subcommittee meeting, referring to six loss-of-load expectation (LOLE) sensitivity case *studies* MISO had recently completed. Three cases emulating poorly planned generation outages showed risk in September, while two cases assuming no load-modifying resource (LMR) participation in addition to the outages found risk in December, January and February.

MISO's current LOLE study assumes all outages are ideally planned and LMRs are available outside of summer, when they're not required.

At the RASC meeting Wednesday, some stakeholders said MISO's analyses were unconvincing because it assumed the worst possible circumstances when searching for new loss-of-load risk.

Of MISO's last 10 maximum generation emergency events, Lopez said, only one has occurred in summer. Since 2016, the RTO has not completed a year without a maximum generation warning or event, amassing 10 emergency events and three warnings that didn't culminate in emergency declarations.

Customized Energy Solutions' David Sapper asked why MISO only used its current resource mix in the study and did not incorporate projected mixes.



Offshore wind additions above 7,000 MW may require additional injections or transmission reinforcements, according to preliminary ISO-NE economic studies. | *ISO-NE*

Lopez said MISO would perform more sensitivities with different mixes, some pulled from its ongoing renewable integration impact assessment. (See ***MISO: Grid Can be Stable at 40% Renewables***.)

Capacity Accreditation

To capture its newly discovered risk outside of summer, MISO plans to make changes to its capacity accreditation process.

Lopez said MISO may move to an "available capacity" paradigm instead of installed or unforced capacity measurements. The new measure of a unit's capacity might involve the use of a historical availability component based on a unit's prior economic or emergency maximum offers in the real-time markets, or an effective outage rate that includes a unit's planned and forced outages.

But Lopez also said MISO might forgo a seasonal accreditation if its load-serving entities can show via a retroactive performance evaluation that installed capacity can meet actual load during peak hours. Some stakeholders said the suggestion sounded very similar to PJM's Capacity Performance rules.

Lopez said MISO will make capacity accreditation changes first to fit the auction's annual format, then refile its accreditation proposal to fit a seasonal capacity auction, if needed. The RTO's proposal to implement a seasonal capacity auction has been pushed back to the 2022/23 planning year, as some stakeholders are asking it to create a cost-benefit analysis.

"Anything we do accreditation-wise, we don't want to unwind if we implement a seasonal auction," Lopez said.

MISO has *said* typical operating margins are "comfortable for the majority of daily peak hours but tighten May through September." The RTO also said most systemwide ramping occurs in the final two hours prior to peak from November through April, when it typically relies more on coal generation to navigate the winter.

"We've got declining margins, a changing fleet and an increasing reliance on new supply and load-modifying resources," MISO CEO John Bear explained during the July Informational Forum. Those changes signal the increasing need for an "availability margin" versus a reserve margin, he said, meaning MISO would take more care to ensure that its reserves are actually on hand when needed. ■

MISO News

MISO Deliverability Plan Prompts Skepticism

By Amanda Durish Cook

MISO has signaled that it's ready to address calls from its Independent Market Monitor and members to tighten capacity deliverability requirements, although some stakeholders are skeptical it can raise standards without increasing costs to customers.

The effort was launched last week with a new deliverability proposal for wind, solar and electric storage resources. The RTO draws a distinction between conventional and intermittent resources for deliverability.

The Monitor contends MISO doesn't properly account for capacity deliverability because its loss-of-load expectation (LOLE) study assumes that all capacity resources are fully deliverable on an installed capacity (ICAP) basis. However, the RTO allows resources to demonstrate deliverability only up to the unforced capacity (UCAP) levels, which tend to be about 5 to 10% below full ICAP levels.

The Monitor has said MISO should assess deliverability for all capacity resources based on full ICAP. Potomac Economics staffer Michael Chiasson said the Monitor first became aware of "MISO's interpretation of its Tariff" after the 2016 auction, when it determined that one unit came up short by "tens of megawatts." However, he said the Monitor's analysis of 2019/20 capacity auction results found that no zones went into capacity shortages because of MISO's capacity deliverability structure.

At a Resource Adequacy Subcommittee meeting Wednesday, MISO floated three *options* to address the issue:

- Use a resource's transmission service request value as the maximum historical output for the average capacity factor, which would stand to reduce capacity credits;
- Require deliverability up to the resource's UCAP divided by MISO's "PKmetric," which is the average capacity factor for each commercial pricing node over the eight daily peak hours since 2005; or
- Require resources to be deliverable to the highest megawatt output value during the eight daily peak hours for the last three years.


| © RTO Insider

MISO's **Darrin Landstrom** said the three-year option has the most potential to be variable: "It's going to be there for three years, then we'll re-examine it. It could go up or down."

The Coalition of Midwest Power Producers (COMPP) last year filed an unsuccessful complaint over the apparent gap in MISO's accounting of capacity deliverability. (See *FERC: No Merit in MISO Deliverability Complaint*.) The group argued that the RTO's "deliverable

MISO News

to load" requirement in the Tariff should be interpreted to require capacity resources to have firm transmission service up to their full ICAP levels. FERC rejected that argument, saying MISO had no Tariff provision to support the group's reading and that there was no evidence the existing practice places reliability at risk.

Necessary?

But some stakeholders think it's unrealistic to assume MISO has enough firm transmission to go around to allow for an increase the deliverability requirement. They also said the RTO should prove that its UCAP deliverability requirements are a problem before making proposals.

"You really think in some of these zones we're going to be able to purchase firm transmission service up to our load? … I don't have any hope that this will be the case," Madison Gas and Electric's Megan Wisersky challenged.

"That's a good point," MISO Executive Director of Resource Planning Patrick Brown said.

"And when do you want resource adequacy? Or do you want to bleed us dry for [cost of new entry]?" Wisersky continued, referring to the risk of putting more transmission service requests into MISO's already overstuffed interconnection queue when there's currently not sufficient transmission available to handle proposed generation.

"That's a good point," Brown repeated.

"This is a serious issue and has the potential for serious rate implications. We are potentially looking at rate shock for our retail customers," Wisersky said.

MISO Director of Resource Adequacy Coordination Laura Rauch said the goal is for resources to carry firm service up to the output they would have in real-time operations. "We do think that there are resources that don't have deliverability up to their summer peak day," Rauch said during the Market Subcommittee meeting in July.

But Clean Grid Alliance's Natalie McIntire questioned whether MISO needed a solution at all.

"My general philosophy is we've identified a gap, and we can address it," Brown said. "Several years ago, when we had a 30% reserve margin, gaps like these weren't a big deal. We don't want to wait until this becomes a problem to address it."

"I think this is a little bit half-baked," WPPI Energy's Steve Leovy said of the proposal.

Landstrom said MISO isn't wed to any of the three options just yet. Brown also said that MISO will continue to study the impact on zones for any new deliverability proposal.

"We aren't going to push someone into an insufficient position where they don't have time to react," Brown said. ■

MISO, Monitor Strengthening Mitigation Measures

By Amanda Durish Cook

CARMEL, Ind. — MISO and its Independent Market Monitor are making several changes to market mitigation procedures — most of which will increase the Monitor's authority to invoke mitigation and issue penalties.

At the Monitor's behest, MISO has agreed to refine Tariff language that only revokes make-whole payment eligibility when a market participant has been "determined to be manipulating or gaming" the RTO's market.

IMM David Patton seeks to have the Tariff clarify that MISO — and the Monitor — aren't required to "establish the intent of the market participant to manipulate or game" the market in order to rescind eligibility for make-whole payments, but need only identify the participant has been "unduly extracting" payments.

MISO will also more strictly monitor generation shift factor (GSF) cutoffs for lower-voltage constraints that tend to have fewer competing suppliers. While the IMM will continue to monitor resources with a GSF of 6% or higher for areas at or above 345 kV, the GSF cutoff will drop to 4% for areas between 138 and 345 kV and even to 3% for areas at or below 138 kV.

Entergy representatives questioned whether the lower GSF cutoffs would lead to over-mitigation of generators.


MISO Monitor David Patton | © *RTO Insider*

"This just identifies more appropriate resources to be screened," MISO Director of Market Design Kevin Vannoy said during a Market Subcommittee meeting Thursday.

Patton also said he'd like to remedy a "flaw" in MISO's Tariff where non-capacity resources are excluded from physical withholding mitigation even if they have market power.

He said the rule should not be considered an extension of MISO's must-offer rule, which he doesn't believe is strong enough anyway.

"If MISO were to propose to eliminate the must-offer, I wouldn't fall on my sword to save it. I believe in markets, that prices should motivate people to want to offer," Patton said at the Market Subcommittee meeting in July.

Patton said the expansion of physical withholding penalties would apply only in "clearly" uneconomic behavior from units. Suppliers without market power will not be beholden to the new rule and are not under an obligation to offer, he said.

The Monitor also wants to raise the threshold for determining impacts to market clearing prices from $10/MWh to $50/MWh.

"The $50 impact threshold is just much too high," Patton said.

Most ancillary service products price below $10/MWh anyway, Patton added, with market clearing prices generally ranging from $1 to $15/MWh.

Patton said he doesn't expect the $50 threshold to result in more mitigation; rather, the change serves to close a rule gap.

MISO intends to file the bundle of changes with FERC later this month or in September. ■

MISO News

MISO Board Committee OKs Seams Study Funding

By Amanda Durish Cook

CARMEL, Ind. — The MISO Board of Directors' Markets Committee agreed to fund the RTO's share of its seams coordination analysis with SPP and received a briefing on FERC's call for cold weather reliability standards Thursday.

During a conference call meeting, the committee unanimously approved MISO's request to pay Potomac Economics $250,000 for its work on the seams project, which the monitoring firm will conduct with the SPP Market Monitoring Unit. The joint analysis will seek to identify issues that may be preventing the RTOs from reaching agreement on an interregional transmission project. (See *RSC, OMS Approve Monitors' Seams Study*.)

The first phase of the study — requested by the Organization of MISO States and SPP's Regional State Committee — will wrap up by the end of 2019.

MISO Independent Market Monitor David Patton told board members he was fairly certain study costs would not exceed $250,000.

"It's a lot of work, but we've taken the time to map out what we're going to be doing. We have a high degree of confidence" costs will stay within the quarter-million dollars, Patton said.

The study has the potential to become a springboard for several past unaddressed State of the Market recommendations, he said.

"If you remember my recommendations, a lot of them are labeled 'externally dependent,' meaning MISO needs cooperation with an outside RTO. I view this as a way to facilitate consensus on [MISO-SPP] issues that have been around for a while," he said.

Patton also said he expects the report will detail recommendations for MISO and SPP, with descriptions of benefits. It's also possible that Patton and the SPP MMU may disagree on recommendations, OMS President Daniel Hall said.

"I want to commend the seams committee and OMS and the RSC for bringing up these issues," Director **Trip Doggett** said. "This is very timely."


| © RTO Insider

Cold Snap Revisit

The committee also heard MISO's perspective on last month's FERC/NERC report on the arctic front that traveled through MISO South and SPP in January 2018. (See *FERC Calls for Cold Weather Reliability Standard*.)

MISO Executive Director of System Operations Renuka Chatterjee *said* a number of challenging conditions, including generator outages, a missed weather forecast and record-shattering load — not just MISO's Midwest-South transfer flow limit — contributed to the winter emergency.

In prior meetings, MISO staff called the report fair and deemed the recommendations sensible, though they said MISO was still reviewing them. (See "MISO Says Winter Standards Reasonable," *MISO Reliability Subcommittee Briefs: Aug. 1, 2019*.)

"When you have a significant event that the temperatures are so far below normal ... it becomes the new standard," Chatterjee said. She said the event, like 2014's polar vortex, will be used as lessons learned and a new example of extreme operating conditions in planning.

MISO President Clair Moeller said the RTO will pay more attention to "localized weather events" in load forecasting in the future.

"Having lived through the 2011 ERCOT *event*, I would say these conditions were exactly what we experienced," said Dogget, a former ERCOT CEO.

Doggett urged MISO to work with its southern generation owners to make sure equipment is winterized. But he also commended MISO operators on their communication during the event.

MISO will hold a winter readiness workshop with its stakeholders in October. The RTO is also circulating a winterization *survey* through Sept. 15 among its generation owners to get a better idea of cold weather preparations. ■

Stakeholders Confused over MISO Roadmap

By Amanda Durish Cook

CARMEL, Ind. — MISO's new Integrated Roadmap format didn't fare well with members, judging by their comments at a special workshop Friday.

The *Integrated Roadmap* is a list of market improvements prioritized partly by the Independent Market Monitor's and stakeholders' preferences. It replaced MISO's previous Market Roadmap earlier this year.

MISO expects to complete the prioritization and identify which market improvements it will seek in 2020 by early November, after it melds its ranking with stakeholders' and the IMM's.

Multiple stakeholders complained that the new procedure is chaotic and hard to follow, with several asking MISO to explain in detail how it tallies results from stakeholder voting.

This year MISO *divided* issue voting by which stakeholder committee would work through a possible proposal. The Market Subcommittee had the most projects to rank, while the Planning Advisory Committee and the Reliability Subcommittee had just one issue each.

MISO market strategy team member Christov Churchward, who joined MISO in June when roadmap ideas were already under discussion, led the stakeholder results presentation. Eight market improvement proposals submitted in spring were part of this year's consideration. (See *Steering Committee Advances Roadmap Suggestions*.)

Despite the confusion, stakeholders rated a multiday market forecast, interconnection queue streamlining, better modeling of combined cycle generators, changing the process for deploying demand response during capacity emergencies and dynamic transmission line ratings as priorities. MISO's ongoing resource availability and need project also earned a top spot from stakeholders.

The draft *ranking* released in spring closely tracked stakeholders' prioritization, though

MISO News

MISO additionally assigned importance to integrating distributed energy resources and electric storage resources.

The RTO removed the Friday presentation from its public website after the meeting to correct errors. As of Monday, it had not been *reposted*.

Monitor David Patton has long advocated for temperature-adjusted line ratings in MISO, where most transmission owners do not adjust their facility ratings to reflect ambient temperatures and wind speeds. Patton has said temperature-adjusted ratings could have saved the RTO about $172 million in production costs over 2017 and 2018.

Xcel Energy's Kari Hassler said it remains difficult to get the roadmap's "parking lot" projects elevated to any importance. The parking lot — projects on indefinite hold — currently holds about two dozen market improvements deemed low priority.

Christov Churchward | © RTO Insider

"They've been low priority for several years. I don't know if they ever get out of the parking lot, or get pushed somewhere else; maybe the basement?"

After a beat: "Oh wait, we're in the basement," Hassler laughed, referring to the workshop's physical location in MISO's Carmel, Ind., headquarters.

"Lower level!" multiple MISO staffers and stakeholders jokingly corrected her.

Short-term Reserves

Meanwhile, MISO continues to target an end-of-the-year filing to create a short-term reserve product. The RTO *expects* short-term reserves will clear $4 million in revenue annually when it goes live in 2021. It also estimates an approximate $5 million annual net production benefit when the reserves are used. Part of the savings comes from MISO operators having to take fewer out-of-market actions, for which it must make revenue sufficiency guarantee payments. (See "Short-term Reserve Filing Coming Shortly," *MISO Market Subcommittee Briefs: July 11, 2019*.)

Stakeholders have asked if MISO's savings estimates are based on real generating units and resources, with some asking why the RTO would pin its hopes on a 30-minute product when generators seldom offer through its 10-minute supplemental reserves program. However, Market Design Adviser Bill Peters said he's spoken to owners of some facilities that can deliver within 30 minutes, but not 10 minutes. ■

MISO to Limit Capacity Resource Extended Outages

By Amanda Durish Cook

CARMEL, Ind. — MISO is working quickly to ensure its capacity resources are mostly accessible for the planning year after this spring's auction cleared a Michigan generator scheduled to be on outage for the entire period.

The RTO proposed a provisional *solution* at the Resource Adequacy Subcommittee meeting Wednesday that would limit extended planned outages to fewer than 90 days to qualify for participation in the Planning Resource Auction. Additionally, resources expected to be unavailable for the first 90 days of the planning year would not qualify for PRA participation.

Cleared resources with planned outages lasting 90 days or longer must replace their capacity or be penalized at MISO's approximately $250/MW-day cost of new entry. Currently, the RTO doesn't impose any penalties for capacity resources that take extended outages.

"If you think about MISO's resource adequacy construct, there is a reasonable expectation of availability," Director of Resource Adequacy Coordination Matt Ellis said.

MISO plans to file the proposal with FERC by mid-October to have it in place in time for the 2020/21 PRA, an unusually fast turnaround for the RTO, which can spend several months to a few years formulating new Tariff language. MISO said it also plans to seek more fleshed-out outage rules for the 2021/22 auction.

Ellis said that while MISO may not be able to make a comprehensive filing now because it must examine several possible unintended consequences, it can impose a straightforward, 90-day requirement.

"It's an incremental change. It's intended to be a step in the right direction — something we can refine further as we go along," Ellis said.

April's PRA cleared a large generator in Michigan's Zone 7 as a capacity resource for the 2019/20 planning year even though it is slated to be on an extended outage for the entire year. The Independent Market Monitor first criticized the move in June. (See "Extended Outages and the Capacity Auction," *Monitor Splits with MISO on Summer Readiness*.)

Ellis said the 90-day requirement is meant to capture the possibility that a planning resource will be out for an entire season. Requiring availability in the first 90 days of the planning year also ensures that capacity resources will be available during summer months when availability is more critical. MISO planning years begin June 1.

Stakeholders immediately inquired about planned outages that come in just under the threshold, but Ellis said MISO is starting by drawing the line at 90 days.

"And honestly, when we discussed this internally, that's the first thing that came up: 'What if units take an 89-day outage?'" Ellis said. "What's the bright line? We chose 90."

Ellis said MISO will revisit its proposal if 88- to 89-day outages begin to become "habitual."

When stakeholders asked what would happen if a generator extends an outage to 90 days or longer, Ellis responded it wouldn't be retroactively penalized to cover replacement capacity. However, MISO and the Monitor would keep a sharp eye for resource owners that might be seeking to game the rule with sudden extensions. Under the plan, the Monitor would have Tariff authority to audit outages for physical withholding.

Stakeholders said the proposal could encourage generators to take forced outages — and the accompanying hit to resource accreditation — over taking a long-term planned outage that would exclude them from a capacity payment for a planning year or face having to replace the capacity at a high cost.

MISO has left the proposal open to other stakeholder comments through Aug. 23. ■

NYPSC Opens Resource Adequacy Proceeding

By Michael Kuser

The PSC held its regular monthly session in Albany on Aug. 8.

New York regulators on Thursday kicked off a proceeding to examine how to reconcile NYISO's resource adequacy (RA) programs with the state's renewable energy and carbon emission-reduction goals (Case *19-E-0530*).

"This item to open an inquiry is important and timely," Public Service Commission Chair **John B. Rhodes** said. "We at the commission have a duty to ensure safe and adequate power. Safe means safe, and adequate means, in this case, [that] there's power when New Yorkers need it. … It's becoming questionable whether the answers that were organized at least 20 years ago are in fact the best answers for the situation we face today."

David Drexler, the PSC's managing attorney, said "a major impetus" for the RA inquiry is New York's recently passed Climate Leadership and Community Protection Act (*A8429*) — particularly its mandate that 70% of the state's electricity be generated by renewable resources by 2030.

Commissioner **Diane Burman** said she understood the need to examine electricity issues, "but I do find it disingenuous to say that we have an obligation to do this when there are many other issues that we have an obligation to examine," pointing to Consolidated Edison's moratorium on providing new customers with natural gas hookups in Westchester County until it can ensure adequate supply to the region.

"I think the chairman nailed it when he said that the current approach was set 15 to 20 years ago, and it's based on the cost attributes of a fossil generator," said Warren Myers, director of regulatory and market economics for the state's Department of Public Service.

The inquiry will focus on answering several questions, including:

- Are the state's energy policies and mandates, such as those related to offshore wind, photovoltaics, other renewables and energy storage, compatible with NYISO's RA mechanisms? If not, what issues are manifested? Also, if not, how could they be aligned? Do policies and market structure mechanisms result in safe, adequate service at just and reasonable rates?
- Is an installed capacity (ICAP) product an effective long-term solution for RA given the required future generating resource mix, which may have lower marginal costs or different availability profiles than many current generation resources in operation? What are the salient attributes of such long-term solutions?
- Is there a preferred mechanism for ensuring RA? What are the cost impacts and benefits to consumers under the various potential RA mechanisms?

NYISO News

- Should alternative approaches be considered to ensure that procurement of generation resources is aligned with state policy goals? If so, which ones? Are there existing or proposed models that might be instructive, such as the state overseeing the RA portfolios of load-serving entities as in California, or should NYISO rules be restructured to accommodate state policies?
- What is the state's role with respect to RA matters?
- What, if any, next steps should the commission take with respect to RA matters?

First of Many

Burman said she would ask the "elephant-in-the-room question," wanting to clarify that the PSC's new effort would not seek to "undo the role of the ISO" regarding RA, "but in fact is looking at how can we work on these issues."

"The elephant is prematurely in the room," Myers responded.

Drexler said, "Actually, from a staff perspective, we're not prejudging any of the issues at this point. This is merely meant to start the inquiry."

Commissioner **James Alesi** supported the inquiry, saying that "New York is already on its way to cleaner energy consumption."

Commissioner Tracey Edwards said it was better to start asking the right questions now than later, "when we'd be doing so in a defensive posture."

Attending his first session since being appointed to the PSC on July 19, Commissioner **John Howard** said, "The truth is, the ISO and its markets work today; the lights stay on; people get paid. If you're an incumbent, things seem to be pretty well-ensconced. However, that doesn't mean there aren't holes that need to be examined. … I believe this will be the first of many inquiries."

In an Aug. 8 blog *post*, Jackson Morris and Cullen Howe of the Natural Resources Defense Council welcomed the PSC's inquiry and raised two points.

"A central concern held by many stakeholders, including NRDC, is that NYISO's capacity market rules could prevent clean energy resources supported by state and local policies from selling in that market, thereby depriving these resources of an essential source of revenue. …

"Another concern is that NYISO's rules undercount the value of cleaner resources like energy storage systems, as well as wind and solar, while over-crediting highly polluting power plants."

Burman expressed additional concern that the proceeding seems to lack direction: "Ultimately, all we seem to be addressing is the capacity markets and buyer-side mitigation, and then taking a look at, in some fashion, whether or not we want to change those rules."

The commission has asked interested parties to submit initial comments by Nov. 8. Commenters can file with the DPS by e-filing or by email to *secretary@dps.ny.gov*, or through the department's Document and Matter Management System. ■

NYISO Manual Changes for New SRE Penalty OK'd

In a brief teleconference meeting Wednesday, the NYISO Business Issues Committee approved manual changes to accommodate a new penalty scheme to improve the ISO's ability to call on external capacity resources.

The revisions to the Installed Capacity Manual and Transmission and Dispatch Operations Manual, aligning them with the external *supplemental resource evaluation* (SRE), passed without opposition.

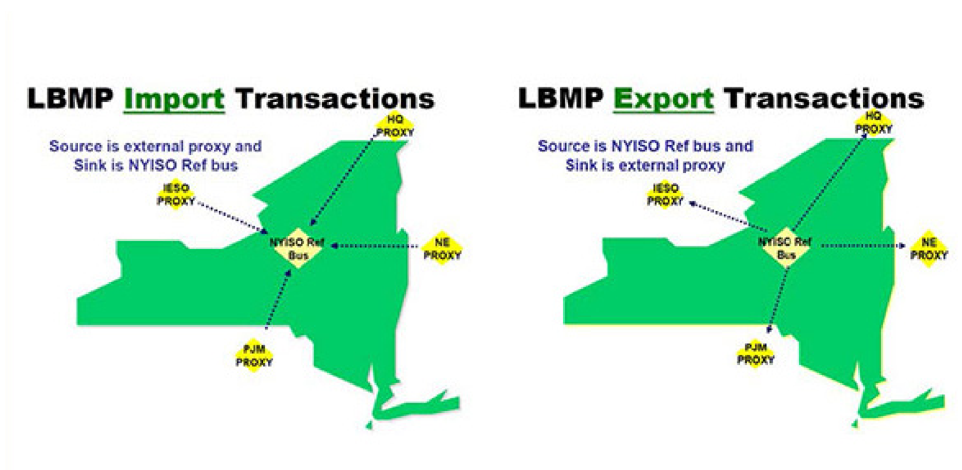
The BIC approved the SRE, which is intended to reduce the risk that capacity-backed transactions from external suppliers to the New York Control Area will be curtailed, on April 17. (See "New External SRE Penalty," *NYISO Business Issues Committee Briefs: April 17, 2019*.) FERC approved the SRE on July 30, effective Aug. 12 (*ER19-2104*).

Under the new scheme, any external resource that fails to meet delivery criteria would 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 to which a supplier fails to respond.

External capacity suppliers would not be subject to the penalty if their failure to deliver is beyond their control. The ISO would calculate deficiencies monthly, using the total number of SRE call hours in a given month that the resource could be available and the total megawatt shortfall in that month.

The market operations report was not included in the BIC meeting materials because the data had not yet been compiled. It will be added to the meeting materials once completed, said Robb Pike, director of market design and product management. ■

— Michael Kuser



LBMP import transactions use an external proxy bus as the source and the NYISO reference bus as the sink. | *NYISO*

PJM News

PJM Members Debate Dueling Tx Replacement Plans

By Christen Smith

VALLEY FORGE, Pa. — Electric distributors want PJM transmission owners to reveal more about how they decide when it's time to replace infrastructure at "the end of its life," a phrase some stakeholders consider too vague, instead preferring the term "asset management."

The war of the words came to a head at Thursday's Planning Committee meeting when American Municipal Power and Old Dominion Electric Cooperative presented a ***problem statement*** and ***issue charge*** to draft Operating Agreement language to address their concerns about the amount of information TOs provide during supplemental project decision-making.

"You say you're willing to share it with the *federales* and the states," AMP Vice President of Transmission Ed Tatum said. "There's no reason you can't share it with the people who are paying for it — who are the reason you're doing it."

TOs said they didn't object to shining a light onto their analyses, per se, but believe new rules governing increased planning coordination belong in manuals, not the Tariff or OA.

Alex Stern, manager of transmission strategy for Public Service Electric and Gas, presented an alternative ***problem statement*** and ***issue charge***. He said using the phrase "asset management" over "end of life" is consistent with acceptable industry terminology and, more importantly, FERC decisions.

"FERC talks about 'asset management,' 'asset activity' and 'asset condition' outside the RTO transmission planning process as opposed to fixed, arbitrary and subjective 'end of life' transmission planning criteria dictating replacement," Stern later told *RTO Insider*. "It's about employing reasonable asset management procedures and performing reasonable analysis of asset condition to ascertain whether the asset remains useful."

Joining PSE&G in sponsoring its alternative was Dayton Power & Light, Exelon and PPL. AMP rejected the TOs' request that it accept their language as a friendly amendment, leaving the second proposal to stand as its own motion.

The AMP/ODEC posting followed a Monday afternoon special session of the PC that further deepened the chasm between

| *NYPA*

stakeholders over how to prioritize projects in the Regional Transmission Expansion Plan. Some members, led by LS Power, believe PJM should take more authority over supplemental projects — some of which include transmission maintenance and the replacement of end-of-life equipment — currently under the sole purview of TOs. (See ***Tensions Boil over on PJM's Supplemental Projects***.)

Supplemental projects are those that PJM considers necessary to address local TO reliability concerns that are not required for compliance with grid criteria governing system reliability, operational performance or economic efficiency. The RTO only conducts reliability planning studies to ensure the projects won't upset the grid's balance.

John Horstmann, director of RTO affairs for DP&L, said the AMP problem statement also excluded mention of:

- Supplemental projects for new customer load or increases to existing loads;
- Supplemental projects to treat load-serving entities comparably to incumbent TO retail customers; or
- Emergency projects required within one year (confirmed by studies performed or approved by PJM planning staff).

TO staff, in some cases, can also provide insight and expertise on local transmission projects that PJM planners — who view the system through a more regional lens — may not know, Horstmann said. "The reality of it is, the transmission is old and it's not old in a nice linear fashion," Horstmann said Thursday, noting that only 30% of the system is less than 40 years old. "There's a big lump of old stuff out there, and its only getting older. … I kind of think we are not recognizing the elephant in the room to some extent: The stuff is old and is going to need to be replaced."

"We agree with that. We fully get it," Tatum said. "We've seen the studies done. We are just saying that if you are doing it, show how you're doing it. We are paying for it, so show us."

The PC spent nearly an hour debating the truncated timeline of both problem statements appearing on the agenda and AMP's request for endorsement after a first read. The debate exposed tensions stemming back to manual language — sponsored by AMP and endorsed at the Markets and Reliability Committee in January — that PJM rejected as contrary to FERC rulings. (See ***PJM Rebuffs Stakeholders on Supplemental Projects***.)

PJM's decision spawned special PC sessions to craft new language targeting the supplemental planning process more generally.

Spending on supplemental projects has tripled over the last 13 years, accounting for 62% of the submitted RTEP project costs since January 2017, according to an analysis from AMP. In 2018, AMP found, TOs added $5.7 billion in supplementals and just $1.5 million in baseline projects into the RTEP.

Tatum said Thursday that TOs have proposed an additional $3.4 billion in supplementals so far in 2019, exceeding the baseline total.

"This is nothing new," he said of the dispute. "The fact of the matter is, people, we've been talking about this a long time, and if there's no hope under the sun of something being able to move forward, then we need to take that as it is."

Other stakeholders wondered if the two problem statements could become one — an idea Tatum and ODEC rejected outright.

"This is not a bad problem statement and issue charge; it's just not what we are talking about," he said of the TOs' initiative.

Stern disagreed, saying there is room for collaboration "so long as there is a genuine desire to explore opportunities for consensus."

"That's what the stakeholder process is supposed to be targeted at doing," he said.

Tatum said that if the PC opts against the problem statement, AMP and ODEC will take the document to the MRC. Stern said he felt stakeholders expressed support for continuing the talks at the PC.

"There's many other ways to get this in front of FERC," Tatum said. "But in my heart of hearts, I believe the way to really do it is to give the PJM stakeholder community the opportunity to weigh in on it so the commission can have a complete record. And that is via the MRC and [Members Committee] on Operating Agreement language." ■

PJM News

Monitor: PJM Markets Remain 'Under Attack'

By Christen Smith

PJM's wholesale power markets remain "under attack" from those concerned about the retirements of legacy generators unable to profit in the face of ever-decreasing energy prices, the Independent Market Monitor said Thursday.

In its quarterly State of the Market *report* released last week, the Monitor — in a thinly veiled dig at PJM's minimum price offer rule (MOPR) revisions pending before FERC — said there's no reason to exclude competitive capacity offers from any generator, nor artificially increase energy prices to benefit struggling nuclear and coal plants.

"The value of markets is under attack, from those who think energy prices are too low and from those who think that market outcomes do not favor their preferred technology, whether it is nuclear, coal, wind or solar," the Monitor said.

Instead, PJM should prevent the markets from reverting back to an integrated resource planning approach "that some would reimpose because markets provide technology-neutral incentives to all market participants, including those who will introduce technologies not yet in existence."

"Markets continue to provide the most efficient way to organize the production of power at the lowest possible cost," the report reads. "Markets are also the most efficient way to integrate state-supported renewable technologies."

Record Low Energy Prices

The Monitor reported that energy prices decreased 35% to $27.49/MWh in the first six months of 2019, compared to the $42.44/MWh seen a year prior. Lower fuel costs contributed to nearly a third of the decline, while decreased load and lower mark-ups comprised the rest. These are the lowest load-weighted real-time energy prices ever seen in PJM, the Monitor said.

The lower prices drove down net revenues for all unit types, including: 65% for combustion turbines, 44% for new combined cycles, 87% for new coal plants, 30% for new onshore wind and 34% for new nuclear plants.

The last includes the subsidized Quad Cities and three other Exelon nuclear facilities in Illinois — Braidwood, Byron and LaSalle. Based on current forward prices, the Monitor said, all four of the plants will fail to recover their avoidable costs in two of the three forward years, with an average annual shortfall of 73 cents/MWh during the shortfall years.

"The value of markets is under attack, from those who think energy prices are too low and from those who think that market outcomes do not favor their preferred technology, whether it is nuclear, coal, wind or solar."

— Monitoring Analytics,
PJM Independent Market Monitor

Exelon told investors earlier this month that without substantive legislative action, the company will close unprofitable plants so as to not "damage the balance sheet sitting around for years with negative free cash flow or negative earnings." (See related story, *Exelon: Market Flaws Threaten Ill. Carbon Policy*, *p.28*.) The company began the deactivation process for its reactor at Three Mile Island after Pennsylvania lawmakers stalled on a plan to keep it running. (See *Exelon to Close Three Mile Island*.)

The Monitor acknowledged PJM's markets are imperfect and said a carbon price would provide a market-based solution to reducing emissions and supporting nuclear plants' economics. But it said "the fact that some plants are uneconomic [without a carbon price] does not call into question the fundamentals of PJM markets. Many generating plants have retired in PJM since the introduction of markets, and many generating plants have been built since the introduction of markets."

Energy Market Competitive, Capacity Market Not

The Monitor said PJM's energy market remains competitive while the capacity market does not — consistent with the Monitor's conclusions in reports released in March and May. (See *Monitor Says PJM's Capacity Market not Competitive* and *Energy Market Competitive in Q1, PJM Monitor Says*.)

As an alternative to PJM's MOPR for addressing the dilemma between "market solutions and potentially inconsistent state policy initiatives," the Monitor again touted its proposed Sustainable Market Rule (SMR). (See *PJM Monitor Reiterates Concerns in Quarterly SOM Report*.)

Under the SMR *proposal*, all nonmarket resources could participate in the energy market without limits, with the capacity market used as a "balancing mechanism" for providing incentives for resources to enter and exit.

"The SMR approach to the capacity market design is simple, based in economic logic, based on the PJM competitive market design and does not require complex rule changes to implement," the report reads. "The SMR would provide a straightforward way to harmonize federal and state approaches to the provision of energy, while respecting the distinction between federal and state authority. The SMR reaffirms the definition of a competitive offer in the PJM capacity market and removes noncompetitive barriers to the participation of renewables."

The Monitor also criticized PJM's energy price formation plan, saying that it guarantees double recovery for generation owners "by breaking the tight link between energy and capacity markets that has been essential to the success of the PJM market design." It also accused the RTO of creating unintended consequences by pushing through substantial energy market revisions without any explanation of how such changes would "enhance or even maintain the competitiveness of the markets."

The Monitor outlined five steps to address what it called legitimate concerns about price formation in the energy and reserves markets:

- Consolidate the tier 1 and tier 2 synchronized markets.
- Increase the scarcity price to reflect the highest generator energy offer allowed.
- Increase the transparency of operator actions, with explicit pricing for defined actions.
- Implement clear rules governing real-time

Continued on page 27

PJM Operating Committee Briefs

BTM Generation Clarifications

VALLEY FORGE, Pa. — PJM's Operating Committee unanimously endorsed clarifications for non-retail behind-the-meter generation (NRBTMG) business rules on Aug. 6, completing the first two key work activities identified in *a problem statement*/*issue charge* approved in March. (See "PJM Continues Review of Non-retail BTM Generation Business Rules," *PJM Operating Committee Briefs: Feb. 5, 2019*.)

The *revisions* to Manuals 13 and 14D will clarify the reporting, netting and operational requirements of NRBTMG that will ensure member and PJM responsibilities, processes and procedures are clear and adequately captured, said Terri Esterly, PJM's senior lead engineer for Capacity Market Operations.

NRBTMG refers to resources used by municipal electric systems, electric cooperatives or electric distribution companies to serve load. They do not participate as supply resources in PJM markets but can be netted against their wholesale load to reduce transmission, capacity, ancillary services and administrative fee charges.

PJM's rules on such resources resulted from a 2005 settlement agreement (*EL05-127*), before development of the RTO's capacity market and Capacity Performance constructs. NRBTMG resources can be called upon during the first 10 maximum generation emergencies annually, while CP resources are required to perform during all performance assessment intervals. BTM operators that fail to perform face reduced netting benefits. In 2006, the grid operator identified about 400 MW of NRBTMG.

Esterly said the manual updates will not change the terms of the 2005 settlement agreement. She also told stakeholders preliminary data collection suggests PJM's existing nameplate capacity clocks in around 1,800 MW. Several generators, however, did not submit summer-rated installed capacity values, likely contributing a significant undercount.

Operations Reports Staying in SOS

PJM will no longer review systems operations reports during the monthly OC — unless it is answering specific stakeholder questions or highlighting an unusual event, such as a polar vortex, Secretary Don Wallin said.

The reports will be posted along with other meeting documents, as usual, but verbal reviews will only occur at the Systems Operations Subcommittee.

In its last review with the OC, however, PJM said it set a new weekend peak value of 150,454 MW — displacing the 149,644-MW record set on July 7, 2012. This year's summer peak of 152,315 MW was hit July 19 during a five-day hot weather alert that covered the majority of the RTO's footprint.

January 2018 Extreme Cold Weather Report

PJM is continuing its review of recommendations included in the NERC/FERC report on the January 2018 extreme cold weather and may bring necessary recommendations to stakeholders at the September OC meeting.

FERC last month called for reliability rules requiring generator owners and operators to winterize their units and provide their reliability coordinators and balancing authorities with information about their preparations. (See *FERC Calls for Cold Weather Reliability Standard*.)

The commission issued the directive as a result of a joint investigation with NERC into the abnormal cold and higher-than-forecast demand that caused MISO and SPP to seek voluntary load reductions and nearly forced load shedding in MISO South on Jan. 17, 2018.

Alpa Jani, PJM's senior consultant for dispatch, said many of the report recommendations were previously discussed in the context of previous polar vortexes and the capacity market. ■

— *Christen Smith*

Monitor: PJM Markets Remain 'Under Attack'

Continued from page 26

pricing through the selection of real-time security constrained economic dispatch (RT SCED) and locational price calculator (*LPC*) cases. LPC, which uses the latest approved RT SCED case as its reference case, produces financially binding LMPs and reserve market clearing prices.

- Develop a consistent definition of energy and reserves products in the day-ahead and real-time markets, including recognition of the appropriate role of demand-side resources.

"This should not be the end of the discussion, but the beginning of a longer, more complete discussion which would lead to incremental steps to improve markets," the report concluded.

Recommendations

The Monitor provided three new recommendations for PJM stakeholders to consider:

- Demand response reductions based entirely on behind-the-meter generation should be capped at the lower of economic maximum or actual generation output.

Quad Cities nuclear plant | *Exelon*

- Load and generation located at separate nodes should be treated as separate resources.
- FERC should require that the open firm flow entitlement (FFE) and firm flow limit freeze date issues be addressed at a technical conference, and that a deadline to resolve the issues that result from the freeze date be set. PJM, MISO and other entities have been working for about five years through the Congestion Management Process Working Group to develop an alternative to the April 1, 2004, "freeze date" used to grandfather permissible unscheduled transmission flows that predated their seams. (See *Outside Parties Slow MISO-PJM Freeze Date Thaw*.) ■

Exelon: Market Flaws Threaten Ill. Carbon Policy

By Christen Smith

Exelon leadership told investors earlier this month that Illinois' transition toward 100% carbon-free power can't succeed without PJM market reforms to keep the company's nuclear plants running.

"The bottom line is fundamental market reforms are needed in the United States if we want to meet the nation's clean energy climate goals, maintain fuel security and a reliable system," CEO **Chris Crane** said. "We need to sustain and increase electrification [and] preserve a significant economic value through good-paying jobs and property taxes. We'll continue to work at the state level and the national level with both Congress and the administration to make this happen."

The company's quarterly earnings report said its Dresden, Byron and Braidwood nuclear plants in Illinois are "showing increased signs of economic distress, which could lead to an early retirement, in a market that does not currently compensate them for their unique contribution to grid resiliency and their ability to produce large amounts of energy without carbon and air pollution."

Exelon said PJM's most recent capacity auction in May 2018 "resulted in the largest volume of nuclear capacity ever not selected in the auction, including all of Dresden, and portions of Byron and Braidwood."

Illinois legislators enacted a zero-emission credit (ZEC) program in 2016 to rescue Exelon's Quad Cities plant along the Mississippi River. The company collected $150 million in ZEC revenue for the second half of 2017.

"We are pursuing a number of market reforms addressing the financial challenges many of our [nuclear] plants face," Crane said. "Against this backdrop, I can also again assure you we will not operate our unprofitable or negative-free-cash-flow plants. You've seen us close money-losing plants in the past. You should expect that discipline to continue if reforms are not enacted."

In the longer term, Exelon told investors the company hopes energy price formation and carbon pricing will help address the market inequities currently hurting its bottom line.

The company's lobbying for clean energy has produced mixed results, so far. While New Jersey approved $300 million in ZECs last year, Pennsylvania lawmakers stalled a plan that would have added nuclear energy into its alternative energy portfolio and saved the remaining operating reactor at Three Mile Island.

"Either we have a clear path to securing them or the units will be shut down," CFO Joseph Nigro said. "We will not damage the balance sheet sitting around for years with negative free cash flow or negative earnings."

As FERC mulls PJM's proposed revision of its minimum price offer rule (MOPR) — which would carve out subsidized generation and then adjust clearing prices as if the resources never left — Exelon continues campaigning for clean energy policies in states throughout the PJM footprint. The company's executive team told investors in Illinois that a coalition of stakeholders wants to expand the state's clean energy mandate from 25% by 2025 to 100% by 2030 to match other progressive states across the country.

That could be a monumental task under current laws, however.

Last month, the Illinois Power Agency warned that the state only secures about 10% of its power from renewable resources. In an interview with WTTW, Director Anthony Star blamed rate caps and a 2016 energy bill that ramped up the agency's procurement responsibilities. He said he hoped legislation would fix both issues.

"Either we have a clear path to securing them or the units will be shut down. We will not damage the balance sheet sitting around for years with negative free cash flow or negative earnings."

— Joseph Nigro, Exelon CFO

Kathleen Barron, Exelon's vice president of regulatory affairs, said the Citizens Utility Board, the Clean Jobs Coalition and both the labor and renewable resources industries all stand behind an expansion of the mandate, noting "the consumer advocate is heavily focused on this policy as well because the question of the state having to pay twice for capacity has been very much in the forefront."

In October 2018, Exelon joined with consumer advocates from D.C. and Illinois, the Sierra Club, the Natural Resources Defense Council, the Nuclear Energy Institute and others to *ask* FERC for a fixed resource requirement (FRR) mechanism that would allow load-serving entities to satisfy their capacity obligations outside of PJM's capacity market by procuring capacity from state-supported resources (EL18-178, et. al.).

"There are a number of parties who will come together in the end to help communicate the message that Chris mentioned this is important for the state, but it's not going to be possible if we can't allow these resources to count as capacity," Barron said. "And that's why the FRR is foundational to getting this policy done."

Earnings Drop

Exelon reported earnings of $494 million ($0.50/share) for the quarter, a decrease from $539 million ($0.56/share) a year earlier. Adjusted operating earnings dropped to 60 cents/share from 71 cents/share in the second quarter of 2018 as revenue dropped to $7.689 billion from $8.076 billion.

Crane noted the company has filed distribution rate cases for Baltimore Gas and Electric, Commonwealth Edison and Pepco.

On July 22, Pepco and other parties filed a settlement agreement with FERC for PECO Energy's formula transmission rate that includes a 10.35% return on equity, including a 50-basis-point RTO membership adder.

Crane said the company was happy with the Trump administration's decision not to impose quotas on uranium, which he said "would have jeopardized the continued operation of commercial nuclear reactors" in the U.S. ■

PJM News

PJM Market Implementation Committee Briefs

Capacity Auction Ruling Anticipated Before 2020

VALLEY FORGE, Pa. — PJM staff told the Market Implementation Committee on Wednesday that they will not file waivers for upcoming capacity auction deadlines and will instead rely on FERC to issue an order on its minimum price offer rule (MOPR) before the end of the year.

Pat Bruno, senior engineer for PJM's capacity market operations, said it's unlikely the commission would respond in time even if staff submitted a waiver for the upcoming Sept. 1 deadline in the 2023/24 Base Residual Auction. The next round of deadlines comes in December, he said, at which point FERC will have "hopefully" issued a ruling.

Last month, FERC halted the 2022/23 capacity auction scheduled for this month, refusing to "rule prematurely" on PJM's request for clarification that if it ran the BRA using the existing MOPR that the commission would also agree to enforce any new rates prospectively, saving the auction from being rerun (*EL16-49*).

The last-minute directive from FERC came just hours after PJM staff told the Markets and Reliability Committee they would move ahead with the auction as planned. The RTO confirmed it would comply with FERC's guidance — though it was the commissioners themselves who expressed frustration about their role in creating market uncertainty for participants. (See *FERC Halts PJM Capacity Auction*.)

'Winter is Coming' ... Along with Gas Contingency Plan (Hopefully)

Thomas DeVita, senior counsel for PJM, told stakeholders that staff are preparing to file a revised gas contingency proposal with FERC by October, with hopes that the commission will give its approval by December.

"Winter is coming," he warned repeatedly, reiterating stakeholder concerns about surviving a third cold weather season without a cost recovery plan for generators forced to switch fuel supplies at PJM's discretion.

On Feb. 19, FERC rejected the member-approved mechanism that would have implemented a process for market sellers seeking cost recovery for certain gas contingencies associated with the RTO's instruction to temporarily switch to an alternative fuel or fuel source because of pipeline breaks or the loss of compressor stations (ER19-664.) The proposal included nine categories of switching costs, such as park-and-loan service charges and overrun charges. (See *FERC Rejects PJM's Gas Pipeline Contingency Proposal*.) The commission also argued that the conditions for switching belong in the Tariff — not just business manuals — and gave PJM a chance to revise the proposal over the spring and summer.

DeVita said FERC staff dropped some hints about how to tweak the filing for better success the second time around. (See *PJM Revisits Gas Pipeline Contingency Plan*.) He said staff discouraged the RTO from submitting an itemized list of switching costs, as it did in the first filing, and instead focused on procedures surrounding "explicit authorization" to switch between pipelines and any new limitations on the amount of gas burned after the switch occurs.

> **"Winter is coming."**
>
> — Thomas DeVita, PJM

In the draft *language* presented Wednesday, staff added "pre- or post-contingency" into the switching process triggered by a manual load dump and removed a requirement that generators must have documentation of unauthorized switching costs before filing for cost recovery at FERC. A reference to opt-in and opt-out intraday offers was also removed.

Staff also added the following paragraph to the proposal, meant to ease members' concerns about the vague definition of switching costs: "PJM will commit to analyze, assess and address through a stakeholder process whether adequate compensation exists for any future operating instructions associated with gas switching that fall outside of the criteria established in this Tariff filing. Such analysis will also consider the mechanisms through which such compensation shall be obtained."

Independent Market Monitor Joe Bowring asked DeVita whether PJM's proposed language would permit companies to include the cost of penalty gas in their offers and therefore charge customers for the much higher cost of power that would result. Bowring pointed out that if the pipeline approved the use of the gas, it should not be treated as penalty gas. PJM indicated that the issue needed to be clarified.

Bowring also noted that the gas contingency procedures did not have a clear requirement that PJM take other emergency actions prior to the contingency, including calling on demand-side resources.

DeVita said the language is on track for endorsement at the September MIC and MRC meetings, with filing scheduled for Oct. 15.

Opportunity Cost Calculator Vote Delayed

Stakeholders delayed votes on several options for a more unified opportunity cost calculator after confusion over the implications of proposed changes left many unsure of how to move forward — if at all.

Bob O'Connell, executive director of regulatory affairs and compliance for Panda Power Funds, sponsored a motion to vote on three packages, drafted in consultation with Dominion Energy, that would streamline PJM's calculator to varying degrees. (See *PJM Stakeholders Push Unified Opportunity Cost Calculator*.)

During a first read of the plans last month, O'Connell said the first package makes small changes that don't force PJM to rewrite its calculator. The second revises PJM's modeling process to mimic the Monitor's, which many stakeholders prefer for its reliability. The third consolidates the former package into one single calculator, "eliminating all compliance risk," O'Connell said.

Under current procedure, market participants can either use PJM's calculator in Markets Gateway or the Monitor's modeling system to build energy cost offers with appropriate adders that help ensure a generator will recoup opportunity costs when its resources have limited run hours for environmental reasons and are scheduled outside of their most economic operating intervals. Some of these opportunity costs arise when regulatory agencies impose environmental run-hour restrictions, physical equipment limitations trigger operational restrictions and *force majeure* events constrain access to fuel.

PJM News

The problem for O'Connell and other stakeholders, however, is the riskiness associated with PJM's calculator, which is designed to give market participants more control over submitted data and, therefore, more opportunity for operator error. PJM staff said the majority of stakeholders — perhaps up to 98% — use the Monitor's calculator already, with just two choosing to use the RTO's within the last year.

"When I look at the Market Monitor's calculator, I view that as very little compliance risk," O'Connell said. "The only issues we have are — are we being honest and forthright with the information we provide to the Market Monitor, and did we copy and paste correctly? From my [compliance] perspective, something like the IMM's calculator is preferable."

Glen Boyle, manager in PJM operations analysis and compliance, pushed back against the simplified explanation of the Panda/Dominion proposals, noting that the calculator changes being suggested raise "serious concerns" — including those that would set aside hours from the performance assessment interval.

"There's already a process in [PJM Manual 13] where if you start to run out hours, you can put those remaining into max emergency," he said. "FERC was very clear in its order on opportunity costs. Only things related to environmental, insurance carrier and [original equipment manufacturing] should be in the calculator. We agree with that, and some of these things shouldn't be included."

O'Connell said the changes deserved further consideration.

"If you look at the situation right now, there's sort of a disconnect between actions a company takes to put a resource into max emergency versus assumptions that are made in the capacity market," he said. "This serves to link them more closely. … [It's] an expectation [of] how market participants should behave with respect to a decision that they are getting down to too few hours. Really, the status quo lacks that linkage."

He did, however, agree that the goal of "getting to one calculator" took priority over approving changes and agreed to drop those elements from the third proposal in the interest of moving forward — prompting Bowring to question the necessity of voting on a plan that appears to require PJM to make its calculator mirror the Monitor's.

"If the point is to force PJM to create a calculator exactly like ours, then I believe that's a demonstrable waste of time and money," he said. "It seems to me you have what you want here."

O'Connell agreed that there was no reason to force PJM to spend money to modify their calculator and that the Monitor's calculator addressed the requirements of members.

MIC Chair Lisa Morelli suggested delaying the votes until the September meeting so that stakeholders could take more time to review the changes contained within.

Modeling Units with Stability Limitations

Stakeholders unanimously endorsed a *problem statement* and *issue charge* from Panda that address concerns over proposed revisions to Manual 10 that would require generators to use outage tickets for stability-related limitations, possibly encouraging price distortion. (See "Generation Outage Revisions Delayed," *PJM OC Briefs: May 14, 2019*.)

O'Connell told the MIC last month that PJM's decision to remove supply from the market to address stability constraints will result in some units committing at price-based offers, rather than cost. (See "Modeling Units with Stability Limitations," *PJM MRC Briefs: July 10, 2019*.) Under the RTO's rules, only the affected generator would know of the constraint, O'Connell said, therefore gaining a competitive advantage over other units and possibly incorporating greater mark-ups into their offers.

As a solution, O'Connell suggested PJM implement a closed-loop interface around the affected resource that restricts the output to below the stated stability limit — and that it must be used in each of the RTO's markets. He also encouraged PJM to publicize stability limits on OASIS prior to contacting the affected generator.

The MIC will work on possible solutions during the committee's meetings over the next few months.

Price Formation

The MIC continues its review of how prices are formed every five minutes in PJM based on a problem statement and issue charge created by the Monitor and approved by the MIC in June.

Catherine Tyler of IMM Monitoring Analytics provided education on the relationship between the megawatt dispatch and price signals sent to generators by PJM systems for each five-minute interval. Tyler explained that the signals should be for the same point in time but are not. She said the practice is inconsistent with basic economic logic and creates incentive issues for generating units that are given price signals inconsistent with dispatch signals and are paid in a manner that does not match their dispatch instructions.

PJM News

This is the case for both energy and reserves.

Manual Revisions Endorsed

The MIC endorsed the following revisions to PJM manuals:

- Manual 11 (Energy & Ancillary Services Market Operations): *Revisions* will document procedures for addressing missing historical performance scores in the regulation market and also clarify that the reserve requirements used in the market clearing process are based on the potential largest single contingencies that are communicated by PJM operations and modeled in the markets clearing software. Scheduled for MRC first read later this month and endorsement in September.
- Manual 18B (Energy Efficiency Management & Verification): *Updates* to conform with Tariff revisions that detail energy efficiency rules issued by authorized relevant electric retail regulatory authorities and those dealing with seasonal capacity resources.
- Manual 27 (Open Access Transmission Tariff Accounting and Manual 28 - Operating Agreement Accounting): *Revisions* include language to comply with electric storage participation mandates from FERC Order 841-A. ■

— *Christen Smith*

PJM PC/TEAC Briefs

PJM Unveils Flat Fee Cost-containment Plan

VALLEY FORGE, Pa. — PJM staff on Thursday unveiled to the Planning Committee a proposed new fee *structure* for a more involved cost-containment process.

The proposal suggests charging a $5,000 nonrefundable flat fee to all developers who submit competitive projects. Itemized study costs will be added as necessary. Mark Sims, PJM's manager of infrastructure coordination, said the intent is to bill projects that incur the extra expense. Late payment and nonpayment conditions have yet to be determined.

Sims previously told the PC that PJM's old tiered approach, approved in 2014, doesn't account for the increased cost of the new comparison framework that involves an independent consultant's review and legal and financial analyses. (See "New Fee Structure for Cost Containment Needed," *PJM PC/TEAC Briefs: May 16, 2019* and "PJM Developing Hybrid Fee Structure," *PJM PC/TEAC Briefs: June 13, 2019*.)

Sims said PJM will host a special PC workshop on Aug. 29 to discuss this structure in more detail, which will eventually be added to Manual 14F.

Cost Allocation Dispute Leaves Tariff Changes in Limbo

PJM staff said required Tariff changes covering cost allocation for transmission projects remain in limbo as the RTO waits on FERC to respond to a motion to address a remand related to the issue.

Pauline Foley, PJM's associate general counsel, said transmission owners made the motion after the D.C. Circuit Court of Appeals "set aside" a 2016 FERC ruling that allowed transmission projects driven by local planning criteria to be exempt from competitive bidding. (See *FERC Sides with Incumbent TOs; OKs Limits on Competition*.)

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On clarification, the court, citing its original opinion, said it held "'only that FERC did not adequately justify its approval of the [Tariff] amendment at issue.' Nothing in the opinion prevents FERC on remand from attempting to 'provide a better justification for its approval of the Tariff amendment.'"

Petitioners Old Dominion Electric Cooperative and Dominion Energy filed motions for an order on remand arguing that the court's decisions leave no doubt that the 50/50 cost allocation for regional facilities is in effect pending further action by FERC. LS Power commented that it is appropriate for the commission to bring the matter to an end.

FirstEnergy, Dominion Solutions

Dominion proposed the following *solutions* for several proposed supplemental projects in Virginia:

- Cut an existing 230-kV line between Roundtable and Buttermilk substations. Construct a 1.8-mile, 230-kV loop to Lockridge substation. At Lockridge, install four 230-kV breakers to terminate the two lines. Install two 230-kV circuit switchers and any necessary high-side switches and bus work for two initial transformers (five ultimate). Cost estimate is $35 million and in-service date is July 31, 2022.
- Install a 1,200-amp, 50-kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer from the existing 230-kV bus No. 5 at Beaumeade. Cost estimate is $750,000, and in-service date is March 31, 2020.
- Re-conductor Cochran Mill-Ashburn 230-kV and Ashburn-Beaumeade 230-kV line segments using a higher capacity conductor, as well as upgrade the terminal equipment to achieve a rating of 1,572 MVA. Cost is $15 million and in-service date is June 1, 2023.

FirstEnergy *solutions* for Pennsylvania projects include:

- Replace line trap and substation conductor at the Shawville 230-kV substation and replace line relaying, line trap and substation conductor at the Shingletown 230-kV substation. Cost is estimated at $900,000 with an in-service date of Dec. 1, 2020.
- Replace line relaying, line trap and substation conductor at Elko-Shawville 230-kV Line 546/666 and Elko 230-kV substation. Replace line relaying and line trap at Shawville 230-kV substation. Estimated cost $1.3 million, with an in-service date of June 15, 2020.
- Replace the Homer City North 345/230/23-kV transformer and associated equipment with 345/230/23-kV, 336/448/560-MVA transformer. Estimated cost is $6.6 million, and in-service date is Dec. 31, 2021.
- Rebuild and reconductor approximately 33 miles of wood pole construction for the Armstrong-Homer City 345-kV line. Estimated cost of $138 million and in-service date of Dec. 31, 2023. ■

— *Christen Smith*

SPP News

Texas PUC Briefs

Continued from page 12

commission was protecting its oversight of ERCOT.

"There are policy decisions made at the ERCOT board we don't agree with. I believe we still have the authority to set that policy and the obligation to set that policy," she said. "I don't want to take away our oversight of those policy decisions."

Chair DeAnn Walker shares the PUC's thoughts and prayers for El Paso Electric employees affected by the Aug. 3 mass shooting.

Walker Warns SPP Recs Could Raise Tx Costs

Walker briefed D'Andrea and Commissioner Shelly Botkin on the SPP Regional State Committee's recent discussions and disagreements over the Holistic Integrated Tariff Team's (HITT) recommendations. The RTO's Board of Directors approved the 21 recommendations, despite some minor pushback. (See *SPP Board Approves HITT's Recommendation*.)

Calling the conversations at the RSC "a whole lot of mess," Walker said the three recommendations assigned to the committee will affect Texas because of changes to cost-allocation methodologies. The committee has until next July to:

- propose how to decouple two transmission pricing zones under SPP's Tariff, creating new, larger zones in one, and smaller subzones in the other;
- evaluate the byway facility cost-allocation review process; and
- charter a study of the generator injection rate (based on energy produced by resources without network or point-to-point service).

(See "Regulators Approve 'Wind-Rich' Report, HITT Recommendations," *SPP Regional State Committee Briefs: July 29 & Aug. 5, 2019*.)

"While most of the utilities here [in Texas] support the decoupling, how those zones would [be] set up is important," said Walker, the lone RSC member to vote against the HITT proposals. "Almost every recommendation I have seen has Texas paying more."

Noting the HITT study was pushed by utilities in wind-rich areas concerned that their transmission spending was benefiting customers elsewhere, Walker said, "We're not wind rich. We're just under wind rich."

"My concern is we end up at the end of the day with everyone else getting what they wanted and us needing to make a fight at FERC," she said.

D'Andrea, who sits on Organization of MISO States' board of directors, said some of the same discussions are being held there. OMS is currently working on long-term transmission planning principles, he said. "That conversation is almost impossible to have without cost allocation," D'Andrea said.

SPS to Refund $14.5M in Fuel Costs

The PUC *signed off* on Southwestern Public Service's request to refund its Texas retail customers $14.5 million for over-collected fuel costs from January 2016 through May 2018. SPS reached a unanimous settlement with commission staff, Texas Industrial Energy Consumers (TIEC) and the Alliance of Xcel Municipalities (AXM) (*48718*).

SPS has a separate docket before the PUC, in which it has asked permission to replace its two seasonal formulas used to determine its fuel factors with a single formula (*49616*).

PUC staffer Stephen Journeay offers advice to the commission.

The company *said* the move is necessary because its new 478-MW Hale Wind Project has changed its resource mix and because SPP's market has affected its system-average fuel and purchased power costs. The new formula will ensure the wind facility's benefits are passed on to customers "timely," SPS said.

TIEC, AXM and the Office of Public Utility Counsel have intervened in the proceeding.

Residential customers will see about a 3.25% increase on their bill from June through September, or about $3.73/month for those using 1,000 kWh/month of electricity, the company said.

Broker Registration Forms OK'd

The commission approved electric *broker registration forms* to comply with *Senate Bill 1497*, which requires representatives paid for brokerage services to register with the state (*49711*).

The bill goes into effect Sept. 1. The PUC will maintain a list of registered brokers on its website.

Thoughts, Prayers for El Paso Victims

Walker opened the meeting by extending thoughts and prayers on behalf of the commission to three El Paso Electric employees who she said had family involved in the city's deadly Aug. 3 shooting. She said one of the employees lost their mother.

"It's rocking the entire community," Walker said. ■

— Tom Kleckner

Load Growth Fuels OGE's Q2 Earnings Results

By Tom Kleckner

OGE Energy on Thursday reported second-quarter earnings that beat Wall Street's expectations and reflected economic growth in its service territory.

The Oklahoma City-based company, parent of Oklahoma Gas and Electric, *disclosed earnings* of about $100 million for the quarter ($0.50/diluted share). A year ago, the quarterly earnings were $111 million ($0.55/share).

Zacks Investment Research's survey of financial analysts had projected earnings of 48 cents/diluted share.

CEO Sean Trauschke said the company added 8,000 more customers than it did a year ago, doubling its historic 1% load-growth rate.

"It appears our rate and economic development efforts are paying dividends," he told analysts during a conference call, noting more than a dozen companies have announced new investments in the region. "Our rates and high reliability are often cited as factors in their decision-making process."

Mild temperatures and severe flooding reduced OG&E's contributions to earnings from 46 cents/share to 37 cents/share when compared to 2018's second quarter. Oklahoma's spring thunderstorms left 20 substations partially or fully submerged, Trauschke said.

Enable Midstream Partners, in which OGE holds a 50% general partnership interest, had earnings of 13 cents/share, up from 11 cents a year ago. The joint venture with CenterPoint Energy has contributed more than $1 billion in cash distributions to OGE since its formation in 2013.

"Both of our businesses performed well in the second quarter and are on plan for the year," Trauschke said.

OG&E has a *rate case* before the Oklahoma Corporation Commission that would allow it to recover about $600 million for installing scrubbers at its Sooner Power Plant and converting two coal-fired units at its Muskogee Power Plant to natural gas.

"Once the final order is issued, this decade of environmental compliance will be complete," Trauschke said. "It's required hundreds of millions of investment dollars. ... Since 2011, we have invested more than $6 billion in our system, and customer rates are lower than they were eight years ago."

OGE reiterated its year-end guidance of $2.05 to $2.20/diluted share.

The company's stock opened Thursday at $42.33. It finished the week up at $42.87 after a late 26-cent drop. ■

Company Briefs

Dominion Submits $33M Battery Storage Pilot Plan

Dominion Energy Virginia announced plans to spend about $33 million to build four battery storage projects at three sites in central Virginia. The projects, which total 16 MW, would be the utility's first use of battery storage.

The pilot projects are required under an overhaul of the state's electric utility regulation. Dominion submitted an application with regulators Friday. If approved, the projects are expected to be operational in December 2020 and would be evaluated over five years.

More: *The Associated Press*

Entergy New Orleans Adding 90 MW of New Solar

Entergy New Orleans has narrowed its search for 90 MW of solar energy to three projects approved by city leaders and property owners.

Two power purchase agreements total 70 MW: a 50-MW site to be constructed on Louisiana State University and a 20-MW site to be built in St. James Parish. The third is a 20-MW facility to be built on 100 acres of flood-protected property at NASA's Michoud Assembly Facility in New Orleans East.

More: *Power Engineering*

Federal Briefs

EPA Submits Final Car Emissions Rule to White House

EPA and the Department of Transportation submitted the finalized Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule to the White House for review, the second-to-last step before the rule is implemented.

The final draft of the rule submitted to the White House's Office of Management and Budget will not become public until the rule is complete. The agencies first submitted their drafts of the vehicle emissions rules for model years 2021-2026 passenger cars and light trucks in August 2018.

The finalization of the rule is expected to be heavily litigated, including through lawsuits threatened by several state's attorneys general.

More: *The Hill*

Judge Approves Sale of Blackjewel Coal Mines to Contura

U.S. District Judge Frank Volk last week approved the sale of mines owned by bankrupt coal giant Blackjewel to previous owner Contura Energy. However, the sale hinges on approval by the federal government, after it objected to outstanding royalties and leasing terms of the Wyoming mines.

Contura initially offered $20.6 million in

July to assume ownership of three Blackjewel mines. But at a three-day auction, Riverstone Credit Partners submitted a credit bid of $20 million for the same mines. The bid from Contura climbed to nearly $34 million by the auction's close, with $24 million dedicated to Riverstone Credit Partners. The auction ultimately brought $54 million in total sales, but of that amount, only $1.6 million will fall under the debtor's estate.

The sale comes more than five weeks after Blackjewel filed for bankruptcy, lost a key creditor and closed 32 mines across the country. Volk also authorized the sale of several other mines and equipment speckled throughout the Appalachian region to seven additional companies during the two-day sales hearing.

More: *Casper Star Tribune*

US Wind Farm Development Sees Record Growth in Q2

Wind farm development activity throughout the country rose to a new high point in the second quarter of 2019, according to new data released by the American Wind Energy Association.

According to the U.S. Wind Industry Second Quarter 2019 Market Report, a record 41,801 MW of wind capacity is currently under construction or in advanced stages of development, representing a 10% increase in activity as compared to this time last year.

There are more than 200 wind projects under construction in 33 states, with 15 of those states having more than 1,000 MW of wind capacity that will come online in the near future. Texas leads the way with the most activity (9,015 MW), followed by Wyoming (4,831 MW), New Mexico (2,774 MW), Iowa (2,623 MW) and South Dakota (2,183 MW).

More: *Digital Journal*

State Briefs

IOWA

Iowa City Council Declares Climate Crisis

The Iowa City Council unanimously approved a resolution declaring a climate crisis, which calls for a 45% reduction in carbon emissions from 2010 levels by 2030 and reaching net zero by 2050. The declaration comes less than a year after the council adopted a Climate Action and Adoption Plan that set a goal of reducing carbon emissions from 2005 levels by 25 to 28% by 2025 and by 80% by 2050.

City staff have been tasked with delivering a report within 100 days on recommendations to accelerate carbon emission reductions in a city in which two entities — MidAmerican Energy and the University of Iowa — account for about 57% of all carbon emissions.

More: *The Gazette*

NEVADA

NV Energy to Pay $1.1M Annually to Keep Clark County

The Clark County Commission adopted a five-year agreement with NV Energy that will see the utility pay the county $1.1 million a year not to leave its electric service.

The contract guarantees $1.1 million in payments for 2019, 2020 and 2021, and requires the county to enroll in the Optional Pricing Program Rate program by 2022. The pricing program would offer a flat rate based on new large-scale solar projects.

Commissioners voted unanimously to adopt the contract, which will make the county at least the fourth government agency to receive direct payments from NV Energy in return for a promise not to leave the utility for another electric provider. The utility has entered into similar contracts with the city of Henderson, the Las Vegas Convention and Visitors Authority, and the Clark County School District.

More: *The Nevada Independent*

NEW HAMPSHIRE

Governor Vetoes Biomass Subsidy Bill

Gov. Chris Sununu vetoed a bill that would have required electric utilities to buy power from the state's six biomass power plants.

The bill aimed to deliver three years of subsidies for the wood-burning plants. A 2018 law meant to deliver similar subsidies is bogged down with federal regulators.

The Republican and Democratic legislators who supported the bill said they want to work to override the veto.

More: *New Hampshire Union Leader*

NEW MEXICO

Albuquerque Gets $2.7M Grant for Electric Buses

Mayor Tim Keller said the city has received a $2.7 million federal grant to pay for five new electric-powered city buses.

The new buses are different from the city's Rapid Transit project, which has been delayed after the city received and returned a new electric bus fleet. The city said the buses malfunctioned.

"The battery technology challenges remain for a 60-foot bus," Keller said. "We'll get there. I really believe that in five years, we're going to be able to start phasing those into electric. But this project is for all our other buses. They are the vast majority of our fleet; the 40-foot workhorses of our city."

More: *Albuquerque Journal*

NEW YORK

NY Spending $2M to Study Offshore Wind Impact

The state said it will spend more than $2 million for five studies to examine ways to reduce offshore wind farms' impact on marine environments and commercial fishing.

The studies followed Gov. Andrew Cuomo's announcement of the first two large offshore wind projects for the state power grid, and include a $500,000, two-year study on the need to "understand and develop safe and efficient access" to fishing grounds while "ensuring that offshore energy projects meet their operational goals."

The projects will produce 1,700 of a potential 9,000 MW planned by 2040 in waterways off Long Island, New Jersey, Rhode Island and Massachusetts. Another project by Norway-based Equinor will be located as close as 15 miles offshore from Long Beach.

More: *Newsday*