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Your Eyes and Ears on the Organized Electric Markets
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April 21, 2020

'Most Efficient' Coal Plant in Bankruptcy Again

Low Gas Prices, Mine Closure Hurt Longview Plant

By Rich Heidorn Jr.

Longview Power, a 710-MW supercritical coal-fired generator that claims to be the most efficient coal facility in North America, filed for bankruptcy Wednesday — for the second time.

Its first bankruptcy in 2013 — when it said malfunctioning equipment hampered its operations — resulted in lenders taking all the equity in the company.

This time, the company says it was done in by liquidity problems resulting from rock-bottom natural gas prices, the loss of a nearby mine, and warm winters and energy efficiency that suppressed demand.

The COVID-19 pandemic didn't help either, CEO Jeffery L. Keffer said in a 21-page affidavit that accompanied the company's Chapter 11 filing in U.S. Bankruptcy Court in Wilmington, Del. The company, which said the plant generated \$28.1 million of adjusted EBITDA in 2019, has \$355 million in debt.



Longview Power plant near Morgantown, W.Va. | Longview

But the company said it has a prepackaged agreement that will allow it to emerge with lower debt. The company has been approved for a Payroll Protection Program loan to cover the wages of its 140 employees and says it plans to continue operations uninterrupted — and even expand with a 1,210-MW combined

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Artificial Island Cost Dispute is Over — Almost (p.34)

FERC: RGGI, Voluntary RECs Exempt from MOPR

Monitor: Md. Costs Likely to Rise with FRR

By Rich Heidorn Jr.

FERC on Thursday clarified that voluntary renewable energy credits (RECs) and participation in the Regional Greenhouse Gas Initiative (RGGI) will not subject capacity resources to PJM's expanded minimum offer price rule (MOPR).

The commission rejected rehearing of its June 2018 order declaring PJM's capacity market unjust and unreasonable (*EL16-49-001, et al.*) and virtually all of its December 2019 ruling spelling out the expanded MOPR (*EL16-49-002, et al.*) but provided clarification on several points.

FERC directed PJM to make a compliance filing within 45 days to set the default offer price floor for new energy efficiency resources at the net cost of new entry (CONE) and existing

EE resources at the net avoidable-cost rate (ACR).

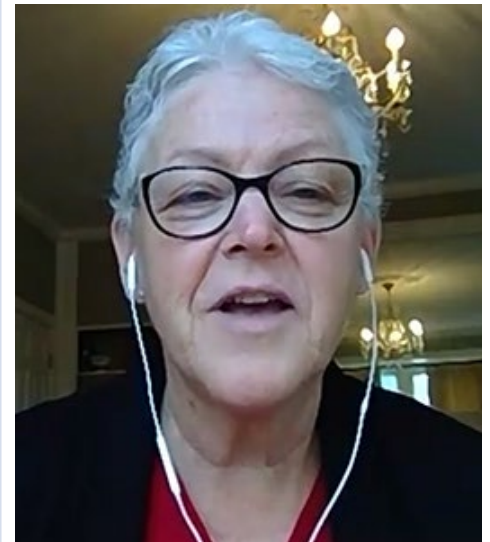
Changes on EE, Interconnection Agreements

Noting PJM's concern with the difficulty of calculating price floors based on verifiable efficiency savings, and the fact that those savings cannot be verified until the resource is in operation, FERC said the default offer price floor for EE "must be based on the costs of installing and maintaining energy efficiency resources, similar to how the default offer price floors for most other resource types are determined."

It clarified that EE may also request the unit-specific exemptions to verify a net CONE or net ACR value lower than the default.

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EBA Holds Annual Meeting Online Successfully



Gina McCarthy, NRDC (p.3) | EBA

COVID-19 RESPONSE

AWEA: COVID-19 Places 25 GW of Projects at Risk (p.7)

MISO to File 1st COVID-19 Queue Waiver Request (p.19)

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Danly Introduces Himself at 1st FERC Open Meeting (p.6)



Michigan Prices Soar in 8th MISO Capacity Auction (p.16)

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Correction

An article in last week's newsletter mistakenly said that methane emissions from the oil and gas sector totaled almost 80 metric tons in 2017. The total was almost 80 million tons. (See [Methane Levels Hit All-time High](#).)

FERC/Federal News

EBA Holds Annual Meeting Online Successfully

Utilities Weathering Pandemic Well, CEOs say, but Challenges Loom

By Michael Brooks

More than 300 energy industry professionals logged into a single video chatroom through Zoom on Wednesday to hear about the latest issues in energy law.

And — besides a half-hour delay while keynote speaker Gina McCarthy attempted to join, and other minor hiccups — the Energy Bar Association's effort to hold its annual meeting through the internet because of the COVID-19 pandemic was a remarkable success.

In addition to McCarthy, CEO of the Natural Resources Defense Council and former EPA administrator, the event featured six panels on topics including notable ongoing litigation, FERC's proposed revisions to how it enforces the Public Utility Regulatory Policies Act and landowner challenges of pipeline certificates. Discussions played out as they normally would at EBA's conferences, usually held at the Renaissance Hotel in downtown D.C., except that panelists spoke from their home offices, living rooms or kitchens. Sometimes, they forgot to unmute themselves before they began speaking.

Meanwhile, attendees commented on the discussions in the text chat sidebar, though this was often limited to remarking on speakers' impressive libraries or their use of Zoom's prerendered backgrounds.

The normally two-day event was compressed into one eight-hour marathon, made further compact by McCarthy's delay and by shortening or even scrapping scheduled networking breaks, in which attendees were divided into separate, smaller chat rooms based on their sector or expertise.

The only breakdown in the meeting came during what is normally the luncheon awards presentation, in which members confirm incoming officers and board members by a ceremonial voice vote. In a physical setting, attendees need only pause between bites of their lunch to shout "aye" in response.

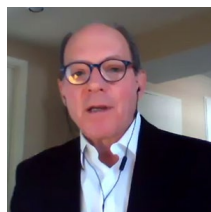
To replicate this experience, EBA attempted to unmute about 300 attendees simultaneously, wrongly assuming that everyone had returned from their lunch break and was paying attention. Robert Fleishman, presiding over the ceremony, was quickly drowned out as "a cacophony" — as one unknown attendee could be heard saying — flooded into the chat room:



NRECA CEO James Matheson addresses EBA annual meeting attendees, held through Zoom, in a panel on utility responses to the COVID-19 pandemic. Matheson is not seen because he joined the meeting by phone. EEI's Emily Fisher moderated the panel. | EBA

conversations, TVs, dogs barking.

Everyone was quickly muted again, and Fleishman asked if there were any "ayes." Those that were paying attention to the proceeding un-muted themselves to respond.



Jonathan Schneider, EBA | EBA

"We don't all speak with one voice clearly," outgoing EBA President Jonathan Schneider said, laughing. "But on this election, I think we've got the message."

At the end of the day, as EBA officials began breaking out the drinks to celebrate the meeting's conclusion, many attendees voiced their appreciation, both through video and text, saying that it had brought some normalcy in a chaotic period.

Industry CEOs Laud Workers; Frustrated with Feds

After the awards ceremony, the CEOs of three major utility associations assured attendees that their members are working effectively despite the unique challenges posed by the pandemic.

Joy Ditto, Thomas Kuhn and James



Joy Ditto, APPA | EBA

Matheson — the chief executives of the American Public Power Association, Edison Electric Institute and the National Rural Electric Cooperative Association, respectively — each said that reliability has not been impacted, despite extensive social distancing measures taken by line workers and a shortage of personal protective equipment (PPE). And each praised these workers as "real heroes," asking attendees to keep them in their thoughts along with other essential workers.

Kuhn noted the severe weather over the Easter weekend on the East Coast, with tornadoes in the Southeastern U.S. and an ice storm in Maine.

"We had to figure out a new way to do business with respect to the pandemic," Kuhn said. "We had to assemble crews" but keep one person per truck. Rather than house crews in trailers sitting in parking lots, "we had to find separate rooms in separate areas so we could operate."

"But we did a fantastic job. This sector ... is used to dealing with disasters and coming together and adapting," he said. "I think we start way, way ahead of every other industry."

Ditto also reported that mutual aid was occurring between APPA members as well as with EEI and NRECA members. She said an outbreak of tornadoes in Tennessee in early March, just before widespread economic shutdowns began in response to the pandemic, provided an early opportunity for utilities to learn how to work together while following

FERC/Federal News



social distancing and hygiene guidelines. The lessons learned during this event were implemented successfully when another tornado shredded Jonesboro, Ark., later that month, she said.

“Given the panoply of issues we face on a daily basis, we still had to learn some things as we’ve gone along in response to COVID-19,” Ditto said. But “the response is occurring. The mutual aid is happening.”

“To watch the participation across the different utilities — investor-owned, municipal and cooperatives — was heartening, Matheson said. “Mutual assistance is one of the best calling cards we got in terms of how we’re committed to keeping the lights on.”

But, all three expressed frustration over shortages of PPE and testing.

Kuhn said EEI was having calls twice daily with the Department of Homeland Security, the Department of Energy and the White House, “but we weren’t able to break through” to them. “We were essentially behind the health care industry — which was obviously appropriate, because they were on the front lines — but what it meant to us was we were not getting the PPEs and not getting the testing.”

Finally, EEI was able to get in touch with the assistant secretary for health, Adm. Brian Giroir, whom Kuhn said understood the situation. “So that’s begun to break, and it’s been terrific,” he said, adding much more will be needed in time for summer.

“This is reflective of a broader national problem, and that’s not the topic of discussion today,” Matheson said. “But, you know, we’re behind on test kits — one could argue we should have been cranking up production test kits a long time ago — so we have a shortage of nationwide kits anyway.

“And for our sector, it becomes really important when you talk about certain critical employees. If you really want to keep the power plants running and keep the right people in the control rooms, you can’t just take someone from one power plant and stick them over in another one to replace someone who got sick,” he continued. “There are unique dynamics to every control room and every power plant. So it’s really important for these key employees that we have the capacity to ... be able to test them on a regular basis.

“It seems pretty straightforward, but this has been a point of, quite candidly, frustration in terms of getting appropriate access to testing kits,” he said. “I think things are moving in a better direction, but I don’t want to say this

issue’s resolved. This is still a big concern for my membership.”

Ditto echoed Kuhn’s and Matheson’s frustrations, but she added that utilities are getting creative with social distancing to ensure “that the most critical workers can continue to work even without testing.”

Several public utilities, including APPA member New York Power Authority, have sequestered their workers in control rooms in 30-day shifts, she said. In other cases, APPA has provided mobile homes for workers to live in. So far, workers have been receptive to the measures, as it protects their families and the public, she said.

“But it’s not ideal,” Ditto said. “It certainly puts more risk on our system than we’d like to bear and surely that the American public would like to bear.”

Matheson said that although he is not aware of any co-ops sequestering, some have gone as far as buying laundry machines just in case.

Financial Concerns Linger

The three CEOs also expressed their worries about the future viability of their members, who have pledged not to charge late fees or disconnect customers for nonpayment — or been barred from doing so by their states’ governors. All are lobbying Congress for long-term support in the inevitable future stimulus packages passed in response to the pandemic.

In the short term, the CEOs said, the focus has been on customers, many of whom are out of work and in desperate need of cash. Kuhn said that for the CARES Act, EEI pushed for increased funding in the Low Income Home Energy Assistance Program, which ended up getting \$900 million.

As publicly owned utilities, APPA and NRECA members must return any surplus funds to ratepayers.

“A number of our members have adopted a policy to accelerate the return of revenue back to consumers ... to get money into people’s pockets more quickly than would have otherwise happened,” Matheson said.

But the combination of nonpayments and lack of commercial and industrial demand “creates an economic hardship across the utility sector,” he said. “As the next stimulus package moves through Congress, it’s a sector that merits some attention. ... In our case, this is about keeping the lights on, and I think it’s a pretty compelling argument.”

The CEOs also echoed arguments they have

made in letters to federal officials. (See *Co-ops, Public Power Seek US Aid in Pandemic.*)

But Matheson also said that even before the pandemic, he had been flustered by a lack of funds from the Federal Emergency Management Agency. Despite having approved cost reimbursement for storms in 2018, “FEMA has never given them the money,” Matheson said. “Those are co-ops that are holding all that expense they did for storm repair on a line of credit and are paying interest on it now. And if they were able to receive their already-approved FEMA reimbursement, that would certainly be a benefit for them” getting through the pandemic.

Ditto said APPA is considering asking for short-term “bridge loans to enable some of our members to get past this squeeze.”

A Post-pandemic Future

The CEOs were asked how they thought the energy industry would change once the U.S. gets through the pandemic and things return to normal.

Matheson said that businesses may realize it is more cost effective for their employees to work from home, at least for part of the work week.

But he and Ditto noted that the pandemic has highlighted that many of their customers still lack access to broadband internet. They both hoped that the crisis would spur federal investment in broadband infrastructure in the rural U.S.

All three CEOs agreed that, at least in the short term, investment in clean energy resources would pause.

When society does start to go back to normal, Ditto concluded, “I’m very optimistic that we can ... go back to work while still ensuring that we stay healthy. I think if we just do it systematically, we’re going to be OK.”

Kuhn said that many are noticing that the air has been cleaner since they began sheltering in place. He speculated that this may accelerate electrification of the transportation sector.

NRDC’s McCarthy also mentioned the reduced emissions in her keynote speech. She said that cable news show hosts always note the substantial reduction in emissions as a result of the pandemic when she’s a guest. “They turn it over to me and seem to think I’m going to go, ‘Wow, isn’t this great?’” she said incredulously. “That’s not how I want to succeed!”

But, she said, “maybe these times are giving us a sense of the importance of science.” ■

FERC/Federal News



IPPs, Trade, Enviro Groups Seek FERC Carbon Pricing Conference

By Rich Heidom Jr.

A broad coalition of independent power producers and renewable energy and trade groups petitioned FERC last week to convene a technical conference on integrating carbon pricing into organized wholesale electric markets (AD20-14).

“Currently, certain FERC-jurisdictional wholesale electric energy and capacity markets are grappling with how to reconcile wholesale markets and state policies related to reducing carbon emissions, which has a bearing on FERC’s jurisdictional scope, such as how these markets function and the prices charged therein,” the group said in an April 13 filing. “In recognition of the fact that a number of organized markets are considering how to incorporate carbon pricing into organized wholesale electric markets to better align with state and regional carbon pricing mechanisms, the time appears ripe for the commission to convene a technical conference or workshop on these issues.”

Notably, the petitioners include both renewable energy advocates who support renewable portfolio standards and generators who say such state subsidies distort capacity markets. For example, the group includes independent power producer Calpine — whose complaint led to FERC’s December order requiring PJM to expand its minimum offer price rule (MOPR) to include all new state subsidized generation — and clean energy and renewable groups: Advanced Energy Economy, the American Council on Renewable Energy and the American Wind Energy Association.

Also signing the petition were IPP groups the Electric Power Supply Association (EPSA), the Independent Power Producers of New York and PJM Power Providers Group, as well as several of their members, including LS Power Associates, NextEra Energy, Brookfield Renewable, Competitive Power Ventures and Vistra Energy. The Natural Gas Supply Association (NGSA) and think tank R Street Institute also joined in.

Notably absent was carbon pricing supporter Exelon, whose nuclear plants have benefited from zero-emission credits (ZECs) and would be subject to PJM’s expanded MOPR. Exelon did not immediately respond to a request for comment.

The request suggests the scope of the conference include a discussion of ways in which

carbon could be priced and how wholesale market pricing and dispatch could account for compliance costs, including a look at existing constructs such as the Regional Greenhouse Gas Initiative (RGGI) and the California-Quebec cap-and-trade agreement, which last month won a *preliminary ruling* in a challenge by the Trump administration.

“We think the commission could grant the request, particularly if other stakeholders welcome the idea of a discussion,” ClearView Energy Partners’ analyst Timothy Fox said in a report to clients. “... If FERC expresses no interest in participating in such discussions, then green-leaning states that have decarbonization of their electric portfolios as a central goal may find the organized markets as presently structured pose an impediment instead of a vehicle to reaching their goals.”

2017 Conference

The groups said the technical conference should “pick up where the commission left off” in its May 2017 technical conference on the interplay between wholesale markets and state policy choices (AD17-11). (See *Power Markets at Risk from State Actions, Speakers Tell FERC* and *ISO-NE Two-Tier Auction Proposal Gets FERC Airing*.)

Fox said FERC’s June 2018 order that proposed a “carve out” for state-sponsored resources in PJM “appeared to be a solid move” in support of one of five potential pathways discussed by FERC staff at the conference, that of “accommodating” state policies. “However, we think the commission abandoned that path in its December 2019 order” directing PJM to expand its minimum offer price rule to cover all new state subsidized resources, he added.

Since the 2017 conference, NYISO has proposed introducing a carbon price in its wholesale market to accommodate the state’s approval of ZECs for some of its nuclear fleet.

PJM has released a study on how it could implement carbon pricing for a subset of its states, with border adjustments to counteract leakage. (See *PJM: Carbon Pricing the Answer to Subsidy Dispute*.)

CAISO implemented a carbon adder in the Western Energy Imbalance Market for bids coming into California from states not subject to the state’s cap-and-trade rules. (See *FERC OKs CAISO Changes to EIM Bid Adders*.)

In addition, ISO-NE CEO Gordon van Welie



A coalition of generators and renewable energy and trade groups asked FERC to hold a technical conference on integrating carbon pricing into wholesale electric markets, saying it should resume the discussion at the commission’s May 2017 conference (pictured). | © RTO Insider

recently expressed his support for carbon pricing. (See *ISO-NE: States Must Lead on Carbon Pricing*.)

Not Seeking a Rulemaking

The petitioners emphasized that they were not asking the Republican-controlled commission to institute a rulemaking, nor suggesting that FERC direct implementation of a carbon pricing mechanism.

“The aim of the technical conference would be to facilitate a dialogue among a broad range of stakeholders and interested parties regarding the opportunities and challenges associated with integrating carbon pricing in the organized wholesale electric energy markets, in recognition that such carbon pricing may be an approach that furthers state policies while preserving the benefits of market-based approaches to electric energy markets.”



Jeff Dennis, Advanced Energy Economy | *Advanced Energy Economy*

tion policy goals.”

Jeff Dennis, managing director and general counsel of Advanced Energy Economy, said in an email that the “set of signatories ... suggests alignment on the broad view that implementing carbon pricing in some form would be a good thing for the markets and for achieving decarboniza-

Continued on page 6

FERC/Federal News



Danly Introduces Himself at 1st FERC Open Meeting

By Michael Brooks

James Danly attended his first FERC open meeting as a commissioner Thursday, albeit virtually, as the proceeding was held by teleconference because of the COVID-19 pandemic.

Danly, who served as general counsel for the commission from September 2017 until March 31, did not issue any concurrences or dissents during the meeting, joining Chairman Neil Chatterjee in voting “aye” on the consent agenda. But he did give some insight into his priorities and regulatory philosophy during his opening remarks.

He listed “correctly incentivizing needed transmission,” ensuring electric reliability and “the efficient and thorough review of our certificate applications” as his top issues.

FERC’s approvals of gas infrastructure “have been challenged repeatedly with ever greater frequency in the courts, and we have a nearly unblemished affirmance rate for the last two and a half years,” he said. “That is a testament to the reasoned decision-making of the commission in issuing these orders and to the legal

durability of the commission’s orders. ... I am adamant that we continue to maintain those high standards in our certificate issuances.”

He also said he was “committed to further refining the pricings in our markets,” asserting that the commission’s rejection Thursday of rehearing requests on its order expanding the minimum offer price rule in PJM “marks an important step in ensuring accurate price signals in the capacity market. But I think there’s more to be done.” He said he was interested in looking at pricing in the energy markets, as well as “the price effects of the participation of non-energy-producing resources in the capacity market.” (See related story, [FERC: RGGI, Voluntary RECs Exempt from MOPR.](#))

Danly concluded with his ideology. “We have to respect the federalist principles that are enshrined both in our authorizing statutes and the Constitution. You know, the commission is not in the business of — typically not in the business of pre-empting state actions. What we do is administer the matters in our jurisdiction, specifically the wholesale rates in interstate commerce. ...

“We need to observe those lines of authority

that Congress has laid out for us. And on that subject, I don’t think the commission should be quick to expand its jurisdiction. As tempting as it can be sometimes, Congress has laid those lines very scrupulously, and we should follow them scrupulously. ...

“Reasoned decision-making is not simply a *sine qua non*. ... It is what the entities who we regulate deserve. ... I would like to see us dispense with as much case-by-case analysis as possible when unambiguous, bright-line rules are feasible.”

In his own opening remarks, Commissioner Richard Glick welcomed Danly and remarked on his impressive vocabulary, including his frequent usage of Latin terms. Because of that, he said, he had a Black’s Law dictionary on hand. At the end of the meeting, Glick explained that *sine qua non* meant “an indispensable requisite.”

Danly also announced the first two members of his staff, who followed him from the Office of General Counsel: Matthew Estes, a former colleague of his at Skadden, Arps, Slate, Meagher & Flom; and Kyrstin Wallach, a 2017 graduate of the George Washington University Law School. ■

IPPs, Trade, Enviro Groups Seek FERC Carbon Pricing Conference

Continued from page 5

“As the petition notes, the signatories do not necessarily agree on all aspects of the role of carbon pricing in wholesale markets, including the degree and manner in which state policies will evolve in the future as carbon pricing is more broadly implemented in the electricity sector and beyond.”

Other members of the coalition issued statements in support last week.

“Calpine’s core principles include support for competition and environmental stewardship,” CEO Thad Hill said.



Calpine CEO Thad Hill
| © RTO Insider

“We believe that placing an economy-wide price on carbon will spur competitive markets to produce the most cost-effective and environmentally responsible solutions.”

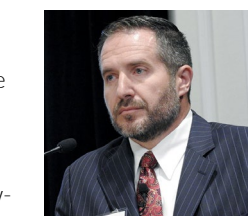
EPSA CEO Todd

Snitchler said, “America’s competitive electricity markets are a success story — and market-based mechanisms such as carbon pricing could be a powerful tool as we write the next chapter.”

“Our hope is that FERC’s willingness to convene a broad stakeholder discussion on carbon pricing will prompt states to seriously consider it as a solution to meeting consumers’ needs and clean energy targets,” said Dena Wiggins, CEO of the NGSA.



Glen Thomas,
president, PJM Power
Providers Group |
© RTO Insider



EPSA CEO Todd
Snitchler | © RTO Insider

PJM Power Providers Group President Glen Thomas said “the piecemeal carbon policies

that are emerging in the PJM footprint are growing increasingly problematic and leading to less efficient markets for consumers. It is time for a regional and national conversation in order to evaluate whether there is a better regional solution out there. We hope that FERC accepts this opportunity to facilitate that conversation.”

Texas-based Vistra “strongly believes that a nationwide carbon-pricing policy, like the [Climate Leadership Council’s] *Bipartisan Climate Roadmap* sets forth, is the most effective, achievable and fair solution,” CEO Curt Morgan said. “Our company also holds that regional carbon pricing is a worthy intermediate step and a discussion at FERC could facilitate further discussions at the ISO and regional level.” ■



Dena Wiggins, CEO of
the Natural Gas Supply
Association | © RTO
Insider

FERC/Federal News



AWEA: COVID-19 Places 25 GW of Projects at Risk

Wind Association Reports 2019 a 'Banner Year' for New Capacity

By Tom Kleckner

The American Wind Energy Association on Thursday reported a "banner year" for the wind industry in 2019 but also acknowledged the storm clouds gathering on the horizon.

John Hensley, AWEA's vice president of research and analytics, said 25 GW of projects — representing \$35 billion in investment capital and tens of thousands of jobs — are at risk because of the COVID-19 pandemic. He pointed to national lockdowns in India and Spain and a slowdown in China as disrupting the industry's supply chain and delaying some projects.

"The U.S. wind industry is not immune to COVID-19 yet," Hensley said. "We're being impacted like any other industry."

Indeed, General Electric's LM Wind Power plant in Grand Forks, N.D., *announced* it will close for at least 14 days as state officials linked 128 positive cases of the coronavirus to the factory, which makes turbine blades.

The industry faces several challenges. It and other clean-energy sectors lost more than 106,000 jobs in March, according to a *report* by BW Research Partnership prepared for climate advocacy group E2. And those sectors will have a tough time arguing to the Republican-controlled Senate for inclusion in any further stimulus legislation that Congress may — or may not — pass. (See *Renewable Tax Credit Extensions Not in Stimulus Bill.*)

Hensley said AWEA is working with Congress to gain some "immediate flexibility" and stave off further losses. He said an extension of the safe harbor continuity window for wind projects begun in 2016 and 2017 "will address the immediate impact the developers are experiencing."

Having learned that tax equity is becoming a concern, AWEA is also pursuing additional relief in the form of direct tax payments.

"Congress has been supportive," Hensley said. "We do hope to have their continued support, so that clean energy can continue creating jobs."

Otherwise, AWEA had nothing but good news to report. According to its "*Wind Powers America 2019 Annual Report*," wind turbines are now the single largest provider of renewable energy in the U.S., surpassing hydro power to account for 7.2% of the nation's electricity production.

Wind capacity cracked the 100-GW barrier in 2019, reaching 105.6 GW with 9.1 GW of new capacity and \$14 billion in new projects. AWEA said the industry employed 120,000 people and provided \$1.6 billion in local payments to communities and landowners last year.

Developers delivered 55 projects in 19 states during 2019, with Texas and Iowa both adding more than 1 GW of wind capacity. Texas has 3.9 GW of wind capacity and Iowa 1.7 GW. Wind energy provided more than 20% of generation in Iowa, Kansas, Maine, North Dakota,



Repowering activities at PacifiCorp's Goodnoe Hills Wind Farm in Washington | AWEA

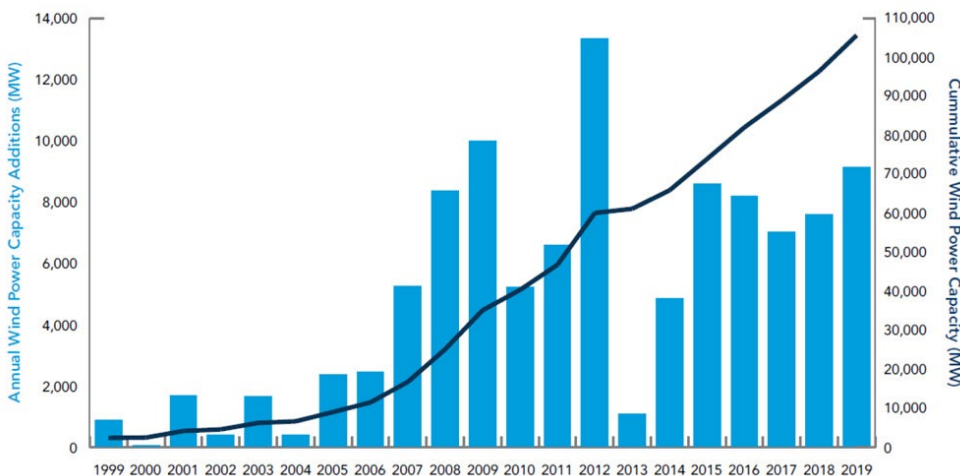
Oklahoma and South Dakota.

All seven U.S. grid operators set records last year for wind output and, with the exception of ISO-NE, for wind penetration. ERCOT produced a record 19,672 MW of wind energy last year, and SPP established a top mark for wind penetration at 68.8% (since raised to 72.4% on April 2).

Utility and corporate buyers, taking advantage of wind costs that have fallen more than 70% during the last decade, also set records in 2019 with more than 8.7 GW of new power purchase agreements. Berkshire Hathaway Energy and Xcel Energy dominate the market with more than 16 GW of capacity between them; Google Energy is the only corporate buyer among the top 10, with 1.4 GW of capacity.

AWEA said the industry began 2020 with a near-record project pipeline of 44 GW of capacity either under construction or in advanced stages of development. Hensley said that while the organization continues to see projects moving forward, "It's too early to know the full extent of those delays on construction plans."

"Affordable, reliable energy is not a luxury — it's a necessity," AWEA CEO Tom Kiernan said in a *statement*. "While we are now working to mitigate the significant disruptions from COVID-19, we know that we will meet these challenges with strong industry momentum." ■



Wind power capacity grew 9.6% in 2019, with an additional 9.1 GW pushing total capacity to 105.6 GW. | AWEA

CAISO/West News



Judge: PG&E Can't Pay Criminal Fines from Victim Trust

By Hudson Sangree

The judge in the Pacific Gas and Electric bankruptcy case on April 14 prohibited the utility from paying its criminal fines from a trust fund meant to compensate fire victims. Instead, the company agreed during a hearing that it would pay its fines from interest on a separate escrow account.

The company agreed to plead guilty last month to 84 counts of involuntary manslaughter and one count of unlawfully starting a fire, with special circumstances including causing great bodily injury to a firefighter over the November 2018 Camp Fire. PG&E's deal with the Butte County district attorney calls for it to pay \$3.5 million in fines and \$500,000 to the

prosecutor's office to cover the costs of its investigation. (See *PG&E to Plead Guilty to Killing 84 in Camp Fire.*)

News that the utility planned to tap the victims' fund for the fines caused an uproar.

PG&E argued that it was required by the terms of its Chapter 11 restructuring agreements to pay the fines and fees from a \$13.5 billion trust it plans to establish for more than 70,000 victims of blazes its equipment started in 2015, 2017 and 2018.

Paying the fines directly, in violation of the agreements, could allow the banks providing billions of dollars in backstop financing to back out of the deal, PG&E lead attorney Stephen Karotkin said during last week's hearing, which

was held via conference call because of the COVID-19 pandemic. He argued that the company had been unfairly criticized for wanting to pay the fines from the victims' trust.

"There was no sinister motive," Karotkin said.

U.S. Bankruptcy Judge Dennis Montali said he couldn't accept PG&E's payment plan. Lawyers in the case had been masterful at preserving their clients' legal rights, he said, "and my right here is to not tell the fire victims, 'You're going to pay \$4 million to a company that has confessed and killed under the criminal laws.'"

The judge had issued a tentative ruling April 10 expressing similar sentiments.

"Some things not only have to be right, but they have to look right," Montali wrote. "Telling fire victims that their money will be used to pay criminal fines and penalties does not look right even if digging through the [restructuring agreement] or the [reorganization] plan would lead to that literal result. Nor does saying to people who lost their homes and their loved ones that \$4 million is 'de minimis.' This not only looks wrong; it is wrong."

PG&E's lawyers agreed that if the judge ordered it, the utility would pay its fines from interest accrued on an \$11 billion escrow account it intends to establish for another group of claimants, insurance companies and hedge funds that hold third-party subrogation rights based on the prior payment of insurance claims.

Once the escrow account is funded, it will take about two weeks to accrue \$4 million in interest, Karotkin told the judge.

PG&E, one of the nation's largest utilities, filed for bankruptcy in January 2019 after two years of devastating wildfires. It's hoping to emerge from bankruptcy by June 30 to avoid a threatened state takeover and to participate in a wildfire insurance fund established under state law.

The company has sent out approximately 250,000 ballots and disclosure statements to fire victims, creditors and others entitled to vote on its bankruptcy reorganization plan. The ballots are due by May 15.

The company has acknowledged its equipment ignited the Camp Fire, killing 84 residents and destroying 18,804 structures in and around Paradise, Calif. An 85th resident who died in the fire was deemed a suicide and not included in the charges. ■



Mailboxes and charred wreckage were all that was left of a senior-citizens' mobile home park after the Camp Fire. | © RTO Insider

CAISO/West News

CPUC OKs Largest Rollout of Covered Conductor

Modern Insulated Lines More Effective than Traditional Tree Wire, Proponents say

By Hudson Sangree

The California Public Utilities Commission on Thursday approved Southern California Edison's ambitious plan to install nearly 600 miles of covered conductor to prevent its higher-voltage distribution lines from starting wildfires.

The move comes after devastating utility-sparked fires swept Northern and Southern California in 2017 and 2018, causing the state and utilities to rethink prevention efforts. (See [California Regulators OK Utility Wildfire Plans.](#))

Covered conductor, with layers of insulation to protect it from sparking vegetation, is one of the main tools that utilities plan to use in fire-prone areas.

SCE's Wildfire Covered Conductor Program would replace bare wires with insulated ones across a sizable slice of its service territory.

This "is the first large-scale deployment of covered conductor in California to harden the distribution system against extreme weather events and designed to reduce wildfire ignition events," Administrative Law Judge Robert Haga wrote in a *proposed decision* that the commission adopted unanimously, without discussion, as one of the items on its consent agenda.

In its ruling, the commission accepted a set-

tlement between its Public Advocate's Office, consumer groups and SCE, granting the utility more than \$407 million for its Grid Safety and Resiliency Program, including nearly \$285 million to install 592 circuit miles of covered conductor — representing about 6% of SCE's primary distribution lines (typically rated at 12 to 16 kV) in high-risk fire areas.

SCE estimated a cost of \$428,000 per circuit mile, including replacing wooden poles with stronger composite ones and installing fiberglass crossarms as needed.

High-voltage transmission lines have been blamed for sparking some of the worst fires in recent years, including the 2018 Camp Fire, the state's deadliest and most-destructive blaze. A Pacific Gas and Electric line fell from a broken C-hook, igniting dry vegetation, state fire investigators found.

Distribution lines have been less prone to starting major fires. But SCE said that from 2015 to 2017, its distribution lines in high-risk regions sparked at least 132 fires large enough to report to the CPUC. The utility said 22 of the fires were started by lines contacting vegetation, more than any other identifiable cause.

"All else [being] equal, there was a relatively greater likelihood that a vegetation-related fault was ultimately associated with a fire event," SCE said in *written testimony* to the CPUC in September 2018 that urged it to approve rate increases to fund its fire-prevention efforts, including covered conductor.

Covered Conductor Improves

SCE said the covered conductor now used is a big improvement over traditional tree wire that had one layer of low-density polyethylene insulation. Today's wire, the new standard, has three layers: an outer coating of high-density polyethylene, an inner wrapping of cross-link polyethylene, and a semi-conducting sleeve wrapped around aluminum or copper wires.

The old covered conductor was heavy, required careful handling to avoid damage, and reduced load capacity because it heated up without the cooling properties of bare wire. It also was subject to degradation from the sun's ultraviolet rays, SCE said.

The new insulated conductor is lighter but still weighs more than bare wire. It catches the wind because of its added bulk and needs stronger poles and cross arms. It also takes



Covered conductor in Southern California is being installed on fiberglass cross arms or in some cases using spacer cable. | SCE

longer to install, said Brian Wilbur, electrical service manager with the Los Angeles Department of Water and Power.

Wilbur made his case in a separate meeting Wednesday of the CPUC's Wildfire Safety Advisory Board, a group created last year to advise the commission's new Wildfire Safety Division. (See [California's New Wildfire Board Holds First Meeting.](#))

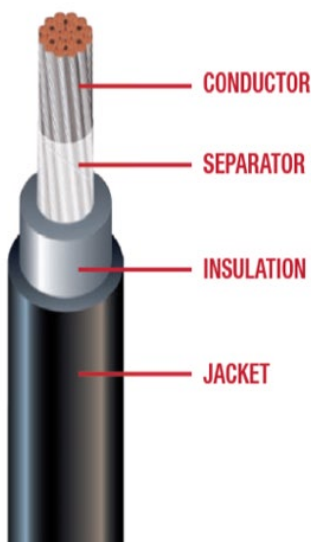
Wilbur said LADWP is using covered conductor in high fire-risk areas.

"Covered conductors or tree wire is certainly nothing new to the industry," Wilbur said. "But the advancement of the technology used today has made tree wire a viable solution in a lot of areas. The old tree wire that we used — that we've had in the systems for a long time — was heavy, required more robust construction techniques, had reduced loading capabilities and was very difficult to work with. Today's tree wire is essentially a stronger construction material, and a lighter installation available on these conductors is becoming a great solution where other mitigating measures are not possible."

Covered conductor is being used with along with vegetation management, composite poles, fiberglass crossarms and other measures, he told the board. The conductor adds an additional layer of safety, he said.

"One of the major things that we learned from the past wildfires is that even the most thorough vegetation management plan may not prevent branches from being blown into lines from an untrimmed palm tree on private property 50 feet away from our lines," Wilbur said. "They can still dislodge, blow long distances and wreak havoc on our system."

"Covered conductors and resilient construction materials are critical in the high-fire-threat area to help prevent these hazards," he said. ■



Three-layer covered conductor is the industry standard for grid hardening against wildfires. | SCE

CAISO/West News

Western Resource Adequacy Program in the Works

Northwest Power Pool Planning RA Function in its Large Footprint

By Hudson Sangree

A resource adequacy program that could eventually encompass eight Western states and two Canadian provinces is being planned by the Northwest Power Pool (NWPP) to ensure sufficient capacity at a time of increasing retirements and shifts toward renewable energy in the West.

The retirement of fossil fuel plants, especially those fired by coal, and the variability of wind and solar resources means a shortfall could be coming starting later this year, NWPP President Frank Afranji said in a webinar Friday.

“Soon, areas in the West may face a capacity deficit of thousands of megawatts. Deficits of that magnitude may result in both extraordinary price volatility and unacceptable loss of load,” Afranji said in his [presentation](#) to the online meeting, hosted by the Committee on Regional Electric Power Cooperation and the Western Interconnection Regional Advisory Body.

More than 2,000 MW of coal generation in the Pacific Northwest will go offline by 2023, and another 1,500 MW will retire by 2029, Afranji said in a recent [article](#). Only four new natural gas plants totaling 1,100 MW have come online in the Northwest since 2011, and battery storage for renewable resources hasn’t reached the point where it can replace traditional generation, he said.

“The conclusion is that the Northwest is on track to face capacity shortages as soon as 2020, with a capacity deficit of thousands of megawatts by the mid-2020s,” Afranji wrote.

“The scale of this challenge led a broad coalition of Northwest utilities to work together to find solutions,” Afranji said in a related web post.

Last year, NWPP issued a [report](#) titled “Exploring a Resource Adequacy Program for the Pacific Northwest.” It noted that resource planning is largely performed by states and utilities, using different standards and methods, and that, as a result, “the region lacks insight into its overall resource situation.”

After the report’s publication in October, NWPP and 18 of its member utilities moved forward to design an RA program intended to improve reliability and lower costs. Members funding the program’s design phase include Avista, BC Hydro, NV Energy, Portland Gen-



NWPP member Avista Utilities, formerly Washington Water Power, owns the Monroe Street hydroelectric plant in downtown Spokane. | [Visit Spokane](#)

eral Electric, Seattle City Light and Tacoma Power.

“The plan is to start with the 18 entities that are currently funding the program, which will cover the majority of the NWPP footprint, and once the program is up and running, cooperate with others that may be interested to join,” Afranji said in an email to *RTO Insider*. “We strongly believe in building this program in building-block type fashion. Once we have the first building block in place successfully, others will be invited to join or may request to join.”

NWPP has a total of 34 members, including major utilities such as the Bonneville Power Administration, PacifiCorp and Xcel Energy, along with smaller public utility districts. Its footprint covers British Columbia, Alberta and all the states in the Western Interconnection except California, Arizona and New Mexico.

The RA program is in a preliminary design phase with more detailed design work scheduled for the second half of 2020. The effort to implement the program is scheduled to start in 2021.

As outlined in Friday’s presentation, the RA program would include a “forward showing” component, in which entities would have to demonstrate they meet capacity requirements

months in advance, and an “operational” component for short-term resource sharing.

NWPP planners have been studying the work of CAISO and SPP, which have their own RA programs, Afranji said.

The NWPP program would be unique because it wouldn’t operate as part of an RTO or ISO, but it could still fall under FERC jurisdiction if it includes binding agreements, planners said. It would be voluntary to join, but once a utility joins, it will be contractually committed to the program’s requirements, they said.

A public [webinar](#) on the proposed program is scheduled for April 24. The RA section of NWPP’s [website](#) features videos and other materials related to the program.

Capacity Shortfalls Ahead?

Concern about Western RA has been a recurring theme during the past year, based largely on the replacement of fossil fuel generation with renewable resources. The number of states and local jurisdictions passing [carbon-reduction requirements](#) continues to grow and now includes California, Nevada and Washington, which have 100% clean energy mandates by midcentury.

Some are worried the difference between

CAISO/West News

those goals and existing capacity will lead to shortfalls. Price spikes in the Pacific Northwest last spring left many questioning the region's RA. (See *NW Price Spike a 'Wake-up Call,' Ex-BPA Chief Says*.)

CAISO and the California Public Utilities Commission have said capacity shortfalls could arise as soon as this summer and worsen next year. The state's policy goals of increasing reliance on renewable energy resources while phasing out natural gas plants is behind the potential problem, CAISO and CPUC officials said. The planned closure in 2024 and 2025 of the state's last nuclear generating station, Pacific Gas and Electric's Diablo Canyon Power Plant, could worsen the situation, they said. (See *CAISO, CPUC Warn of 'Reliability Emergency'*.)

In response, the CPUC ordered all load-serving entities under its oversight to collectively procure 3,300 MW of capacity, on a basis proportional to projected load, by August 2023. The CPUC voted in November to recommend that the State Water Resources Control Board allow four once-through-cooling gas plants built in the 1950s and 1960s to remain online even though they are the last of their kind and are slated to retire by the end of the year.

Concerns about a lack of coordination and oversight in Western markets have been raised in meetings of the Western Electric Coordinating Council. (See *Western Reliability Margin is Thin, WECC Warns*.)

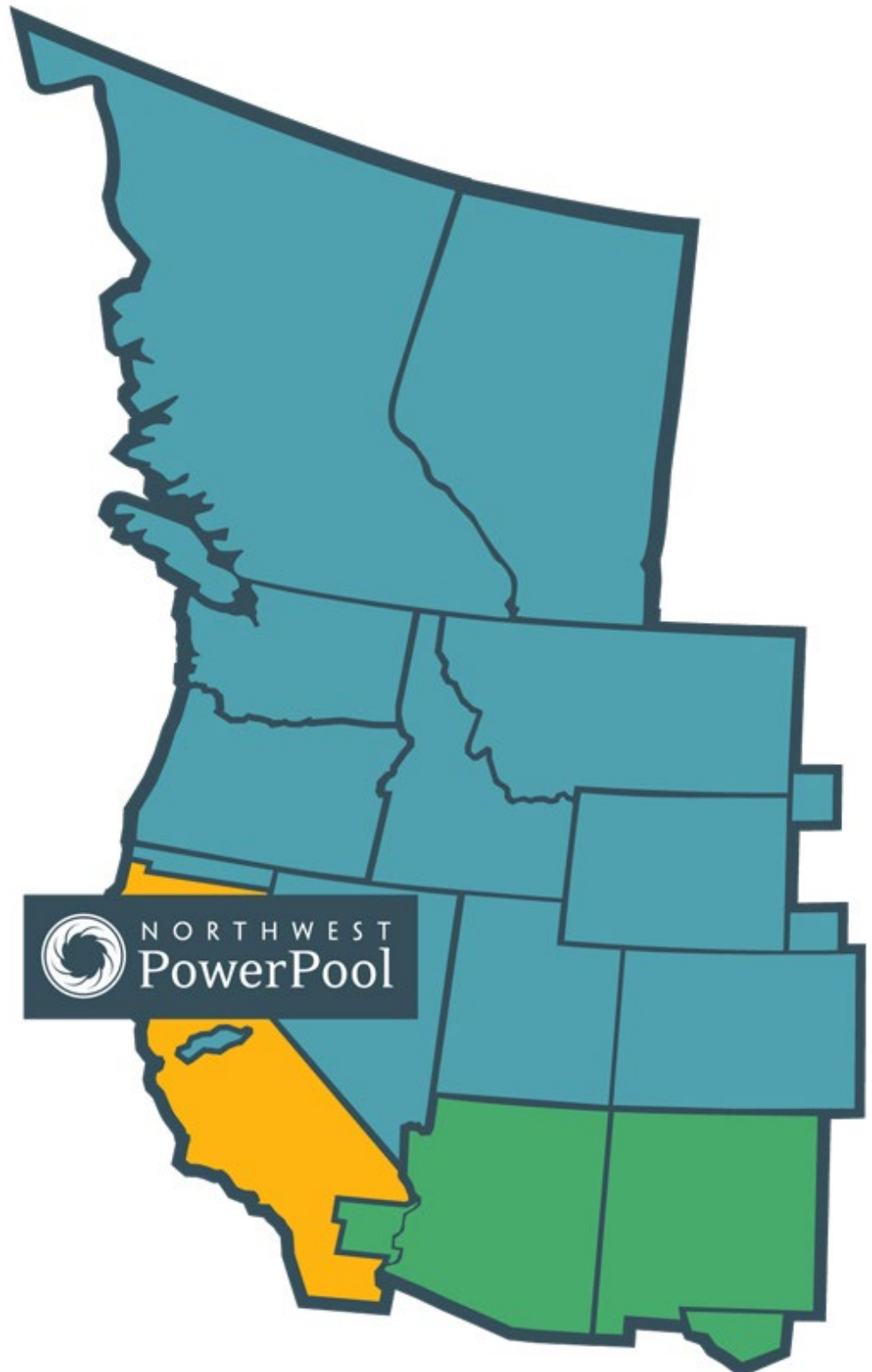
A working group within WECC reported in February that the expected expansion of CAISO's Western Energy Imbalance Market from a real-time only market to a day-ahead market will yield reliability benefits that could outweigh expected risks in the West. But those assurances haven't done much to eliminate concerns. (See *Study Gauges Reliability Benefits of EIM Day-ahead*.)

WECC has an RA role, but it is more limited than that of the proposed program, NWPP said in its October report.

"Although both NERC and WECC publish information on resource adequacy planning, ensuring resource adequacy is the responsibility of utilities, state utility commissions, and other local and regional governing bodies," it said.

Afranji said NWPP's RA efforts will bolster WECC's efforts.

"As to the WECC, this program will be complementary to the RA activities they are engaged in," he said. "The NWPP is part of WECC, and we have a great and symbiotic relation with them." ■



The footprint of Northwest Power Pool, in blue, covers eight states and two Canadian provinces. | NWPP

ERCOT News



ERCOT Board of Directors Briefs

Texas Grid Operator Continues to Monitor COVID-19's Effects

ERCOT's Board of Directors gathered briefly in a conference call April 14 to discuss the grid operator's response to the COVID-19 pandemic.



ERCOT CEO Bill Magness | © RTO Insider

CEO Bill Magness, acknowledging the "unusual meeting format," detailed ERCOT's *plans* and actions taken since March 3, when the Texas grid operator first limited employee travel and directed that all meetings be conducted

via webinars or teleconferences. Staff were directed to work from home on March 18 if they did not have on-site responsibilities, an order that extends through May 3.

He thanked employees and contractors for staying in regular contact with ERCOT stakeholders and "working to ensure our response is coordinated with theirs."

"In the best of times, ERCOT employees are good problem solvers and devoted to their mission," Magness said. "Those characteristics have proven extremely important during these difficult times."

ERCOT will continue to develop contingency plans to protect the health of on-site workers "before conditions become closer to normal," Magness said. He said it continues to solicit advice and guidance from public health and regulatory authorities, its U.S. and Canadian grid operator counterparts and the Texas electric industry.

"There is great uncertainty about many things in today's world, but I feel confident the Texas summer will still be hot," he said.

ERCOT said in March that it foresees record electric usage and tight reserves this summer, but that it has sufficient capacity on hand. It plans to release a final summer resource adequacy report and a capacity report in May. (See [ERCOT Sees Summer Repeat: Record Peak, Tight Reserves.](#))

COVID-19 has begun to have a larger effect on the grid operator's load patterns, according to its most recent analysis. Daily peaks were consistently lower during the week beginning April 5, dropping about 2% despite several hot

days. Energy usage was down 4 to 5% during the week.

Virus' Effects Begin to Affect Load Patterns

ERCOT on Thursday *told* the Texas Public Utility Commission that it has entered into loan agreements with Texas' transmission and distribution utilities — Oncor, CenterPoint Energy, AEP Texas and Texas-New Mexico Power — to fully fund a \$15 million COVID-19 relief program for residential customers having difficulty paying their bills (50664).

The PUC in March ordered the fund's creation. It applies to customers within ERCOT's footprint.

Board Approves 4 Change Requests

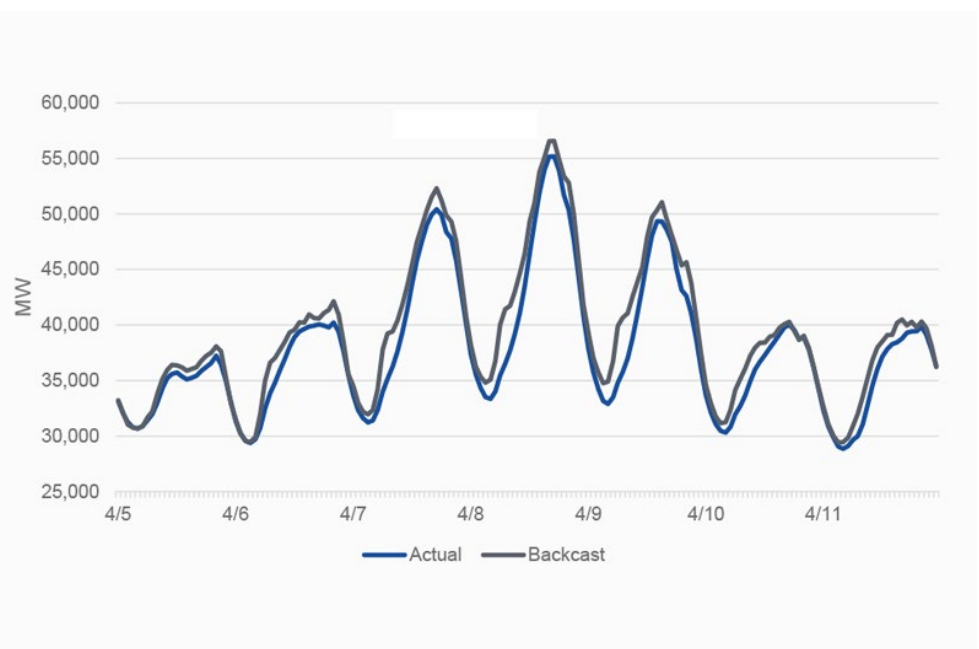
The board unanimously approved three Nodal Protocol revision requests (NPRR) and a single change to the Planning Guide (PGRR):

- **NPRR953:** defines "relay loadability rating" to align with NERC's definition changes, which adds a requirement to include protection system limitations for operational planning analysis and real-time assessments. The changes also support ERCOT housing and monitoring the relay loadability rating in Energy Management System applications.
- **NPRR997:** requires an entity controlling a primarily natural gas-fired generation

resource to supply ERCOT with a declaration contained in the summer weather preparedness form. The declaration should state that the resource entity or the resource entity's qualified scheduling entity has made a written effort to communicate with the operator of each gas pipeline directly connected to the entity's generation resource to coordinate any planned pipeline outages to maximize the resource's availability during the summer peak load season.

- **NPRR998:** establishes a requirement that ERCOT post all emergency response service deployments and recalls to the Market Information System's public area.
- **PGRR075:** requires resource entities and interconnecting entities to provide model-quality test results that demonstrate appropriate performance for submitted dynamic models. Also clarifies that dynamic model data shall be provided using the appropriate dynamic model template; raises awareness of requirements associated with user-written dynamic models; and makes various miscellaneous language updates and corrections, including the elimination of a section superseded by NERC Reliability Standard [PRC-002-2](#) and a Nodal Operating Guide section on phasor measurement recording equipment. ■

— Tom Kleckner



ERCOT's load patterns during the week beginning April 5 | ERCOT

ERCOT News



Texas Public Utility Commission Briefs

PUC Tweaks its Response to COVID-19 Coronavirus

The Texas Public Utility Commission on Friday issued several orders revising its *efforts* to mitigate the economic effects of the COVID-19 pandemic (50664).

The commissioners approved:

- A July 17 end date for enrollment in the PUC's *COVID-19 Electricity Relief Program*.
- A May 15 end date for suspension of disconnections by vertically integrated utilities



The Texas PUC's April 17 open meeting begins.

outside the state's competitive areas. The order applies to Entergy, El Paso Electric, Southwestern Public Service and Southwestern Electric Power Co.

- A May 15 end date on *waivers of late fees* for retail electric providers' residential customers in competitive areas.

The relief program was originally set to expire in September. It is funded by a 3.3-cent/kWh charge added to electricity bills. Among its other provisions, the program suspends disconnections for nonpayment for eligible residents who sign up for payment plans with their electricity providers.

PUC Chair DeAnn Walker said during the commission's open meeting Friday that, upon reflection, six months was "too long."

"That's why I dialed it back to July," she said, promising to revisit the issue during the PUC's May 14 open meeting.

"I firmly believe that no one is going to get out of this unscathed," Commissioner Shelly Botkin said. "Everyone is going to be impacted, personally and financially."



Commissioner Shelly Botkin shares her thoughts on the PUC's COVID-19 relief fund.

Commission Approves Advanced Metering Rules

The commission adopted a *rulemaking* on advanced metering that would use on-demand reads instead of real-time information sharing with home appliances and systems. The rules will allow utilities outside ERCOT to recover costs of the smart meters (48525).

The state's utilities said the real-time requirements would have been more costly to customers. ■

— Tom Kleckner

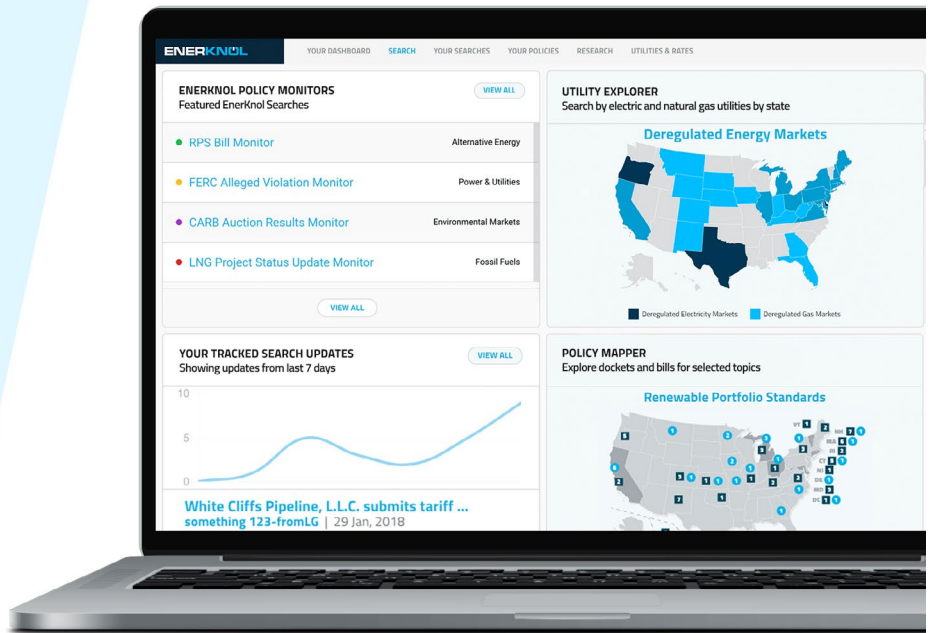
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ISO-NE News

ISO-NE Order 841 Rehearing Request Denied

By Michael Kuser

FERC rejected ISO-NE's request to rehear its decision requiring the RTO to revise its energy storage rules to account for a resource's state of charge in the day-ahead market (ER19-470-003).

The commission last November conditionally *accepted* ISO-NE's Order 841 compliance filing, asking for additional changes to clarify the application of transmission charges to electric storage resources — an aspect of the ruling the RTO did not contest. (See *Storage Plans Clear FERC with Conditions*.)

But ISO-NE did seek rehearing of FERC's determination that the proposal failed to show how the RTO would account for maximum run time and charge time, state of charge, and maximum and minimum state of charge in its day-ahead market, leaving storage resources open to infeasible schedules.

In its rehearing request, ISO-NE said that FERC erred in finding that the proposal failed to account for state of charge in the day-ahead market, contending that storage resources could account for their day-ahead state of charge by incorporating that state of charge into their maximum daily energy limit and maximum daily consumption limit parameters.

ISO-NE also argued that the commission's requirement that the RTO "account for the resource's state of charge at the start of each day-ahead market interval" would not prevent a storage resource from receiving an infeasible schedule.

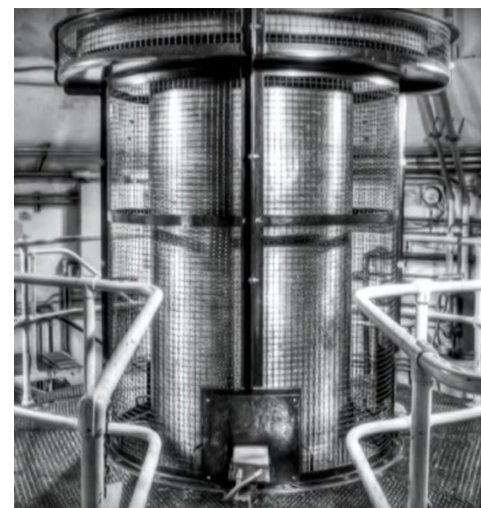
In Thursday's order, the commission emphasized that Order 841 defines state of charge (as a bidding parameter) as the level of energy that an electric storage resource is anticipated to have available at the *start* of the market interval rather than at the end.

FERC found the day-ahead market provisions in ISO-NE's proposal do not comply with Order 841, which requires RTOs to account for state of charge so that electric storage resources can participate in the energy market without receiving dispatch points that violate their physical and operational limits.

"ISO-NE fails to recognize that its maximum daily energy limit and maximum daily consumption limit parameters only account for the cumulative amount of energy an electric storage resource can charge or discharge over the entire operating day, as opposed to at the start of each market interval," the commission said.

The RTO had also contended that the commission had not given due weight to its efforts to integrate co-located storage resources into its markets. But FERC found that the fact that ISO-NE's failure to account for state of charge and duration characteristics in the day-ahead market might better accommodate co-located facilities had no bearing on whether its electric storage resource participation model complies with Order 841.

The commission also found that issues regarding "the participation of electric storage resources co-located with other resources in ISO-NE markets are beyond the scope of this proceeding because Order No. 841 did not ad-



The 1,143-MW Northfield Mountain pumped storage hydro facility | FirstLight Power Resources

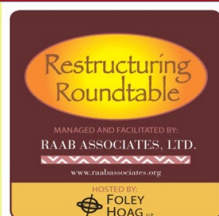
dress co-location of electric storage resources with other resources."

"We note, however, that nothing in the commission's directives precludes ISO-NE from developing market rules tailored to electric storage resources that are co-located with generation," the order said.

Finally, ISO-NE had argued that investing time and resources to change the day-ahead market on the current software platform would not be cost-effective while it is in the process of building a new platform. It requested that if rehearing was denied, the commission allow for an effective date of Jan. 1, 2026. FERC said it would address the effective date separately (ER19-470-004). ■

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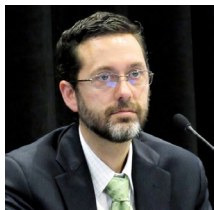
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MISO News

Monitor Casts Doubts on MISO-SPP CTS Benefits

By Amanda Durish Cook

SPP's Market Monitoring Unit is cautioning that MISO and SPP must rethink some of their fees and practices before rolling out coordinated transaction scheduling (CTS) across their seam.



SPP MMU Executive Director Keith Collins | © RTO Insider

MMU Executive Director Keith Collins said that introduction of CTS to maximize use of unscheduled transmission capacity could be ineffective unless the RTOs remove the transmission fees and market charges they impose on each other.

"The benefits are difficult to quantify," Collins said during an April 13 teleconference of the Seams Liaison Committee (SLC) of the Organization of MISO States (OMS) and the SPP Regional State Committee (RSC).

Collins said he's collaborating with MISO Independent Market Monitor David Patton on a study to quantify possible benefits, which will likely be finished in early May. The study is part of the monitors' joint investigation of seams issues performed at the behest of regulators in both footprints.

"If we leave things as is, I think it's important to understand that there may be no benefits. ... There need to be some additional changes in order to unlock benefits," Collins said.

He additionally advised that MISO and SPP

must improve the accuracy of their price forecasting to ensure that CTS delivers on its promises. The current approach to calculating forecasted prices "removes all benefits of a CTS product" because both RTOs find it difficult to anticipate price spikes or negative prices, he said.

"Assuming the current market products and market constructs, there is potentially no benefit to implementing CTS. Assuming no transaction costs and perfect knowledge of prices, CTS can likely improve total market welfare," he said.

Collins singled out SPP for its often unstable prices.

"When prices can go up and down several hundred dollars in the space of five to 10 minutes, it can erode some of the potential benefits of CTS if you were caught sending power at the wrong time," he said.

SPP will soon file with FERC for approval of a ramping product designed to address its price volatility, which Collins said should help facilitate use of CTS.

MISO and PJM launched CTS across their border in late 2017 to allow market participants to schedule economic transmission transactions based on forecasted energy prices. PJM reported in November that CTS transactions accounted for about 19 MW per interval from June to September 2019.

M2M Efforts Proceed

Meanwhile, MISO's IMM is wrapping up a study of the effectiveness of a MISO-SPP

effort to coordinate the management of congestion on market-to-market (M2M) flowgates when one RTO is able to provide relief for a constraint.

Patton said he estimates that M2M congestion "would fall by \$35 million annually if the M2M processes were administered perfectly." The RTOs combined rack up a little more than \$184 million per year in M2M congestion because of delays or failures in testing for M2M flowgates and delays in activating them for monitoring.

To maximize flowgate management, Patton said, the RTOs should seek out, test and activate as M2M constraints the shared transmission most prone to binding. He said MISO and SPP could "accelerate" their testing and activation efforts.

The IMM will release final study results and more pointed recommendations in May.

Unsurprisingly, SPP's Riverton-Neosho-Blackberry flowgate on the Kansas-Missouri border again weighs in as the most expensive based on preliminary numbers, costing MISO nearly \$13 million in M2M settlement payments to SPP over the past two years. The flowgate has routinely been cited as the most expensive between the RTOs. (See *SPP Briefs: M2M Payments from MISO to SPP Eclipse \$32M.*)

MISO and SPP said they are working together to estimate the congestion costs for each RTO for the top 10 most expensive flowgates in each direction. RTO staff said they would present the congestion cost estimates of the 20 flowgates at the SLC meeting in May. ■

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MISO News

Michigan Prices Soar in 8th MISO Capacity Auction

All Other Zones Below \$7/MW-day

By Amanda Durish Cook

MISO's eighth annual capacity auction marked the RTO's first clearing price set by its cost of new entry (CONE), as prices in the Lower Peninsula of Michigan rocketed to almost \$260/MW-day while all other zones cleared under \$7/MW-day.

Zone 7 cleared at the CONE price of \$257.53/MW-day for planning year 2020/21, beginning June 1.

The RTO's CONE is used as the maximum offer and clearing price in the Planning Resource Auction. CONE represents the estimated annualized capital cost of constructing a 237-MW combustion turbine plant in different locations in the footprint.

Since beginning its capacity auctions in 2013, MISO has never experienced prices set by CONE. This year's capacity prices in Lower Michigan are more than 10 times the price of

capacity paid in the last planning year.

The RTO said Zone 7 fell 123 MW short of its nearly 22-GW local clearing requirement and had to turn to other zones for capacity procurement, thereby triggering the CONE price. The RTO said only about 1,150 MW of load — 6% of Zone 7's forecasted peak — must pay the CONE rate because MISO is mostly composed of vertically integrated utilities that procure their own capacity outside the PRA.

"The results also reflect the industry's ongoing shift away from coal-fired generation and increasing reliance on gas-fired resources and renewables," the RTO said in a [release](#).

All other MISO capacity zones remained below \$7/MW-day, with most around \$5/MW-day:

- Zones 1-6 — which include Minnesota, Iowa, Illinois, Indiana, Missouri, Montana, Wisconsin and the Upper Peninsula of Michigan — cleared at \$5/MW-day.

- Arkansas' Zone 8 and Mississippi's Zone 10 cleared at \$4.75/MW-day.

- Louisiana and Texas' Zone 9 cleared at \$6.88/MW-day.

Additionally, external resource zones cleared between \$4.89 and \$5 depending on where they connect to the MISO system.

Last year, all zones cleared at \$2.99/MW-day except for Zone 7, which cleared at \$24.30/MW-day. (See [Most MISO Zones Clear at \\$3/MW-day in 2019/20 PRA](#).)

The RTO received 141.5 GW worth of offers in this year's auction, about 6 GW above the nearly 136-GW reserve margin requirement for June 2020 through May 2021. It expects an almost 122-GW coincident system peak this summer.

MISO also said the South-to-Midwest transmission transfer limit bound during the

Zone	Local Balancing Authorities	Price \$/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	\$5.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	\$5.00
3	ALTW, MEC, MPW	\$5.00
4	AMIL, CWLP, SIPC	\$5.00
5	AMMO, CWLD	\$5.00
6	BREC, CIN, HE, IPL, NIPS, SIGE	\$5.00
7	CONS, DECO	\$257.53
8	EAI	\$4.75
9	CLEC, EES, LAFA, LAGN, LEPA	\$6.88
10	EMBA, SME	\$4.75
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	\$4.89-5.00



ERZ = External Resource Zones

MISO News

auction, causing a 25-cent price separation between the regions. The last time the transfer limit bound in the capacity auction was in 2016. Zone 9 also experienced a slightly more expensive clearing price than most other zones because of a higher local clearing requirement. MISO predicts zones will hit their summer peaks at different times and assigns separate local clearing requirements.

MISO stressed that it continues to have sufficient capacity in the footprint.

"This year's results reflect adequate resource availability for the upcoming planning year," MISO Executive Director of Market Operations and Resource Adequacy Shawn McFarlane said. "The grid's capability to effectively transfer resources among zones remains strong, and we appreciate our members' participation."

"Most of the zones cleared at a relatively low prices, reflecting trends we've seen over the last few years. The vast majority are well positioned to meet their capacity needs," MISO Manager of Capacity Market Administration Eric Thoms said during a special conference call to discuss auction results Wednesday. "That's indicative of the makeup of the footprint."

But Thoms said Zone 7 has frequently been "very tight, capacity-wise."

Thoms also emphasized to stakeholders that CONE is function of MISO's FERC-accepted Tariff, and most load-serving entities in lower Michigan would not be exposed to the CONE price.

"Per the Tariff, if the zone is short of its local clearing requirement, it's capped at CONE," he explained.

Thoms also said Zone 7 was impacted by a new rule this year that prohibits resources from offering into the auction if they will be on outage for longer than 90 days of the first 120 days of the planning year. Thoms estimated that the rule impacted 200 to 300 MW of planning resources in Zone 7.

"Being that Zone 7 was tight on a razor's edge ... the outage policy contributed to the zone not being able to meet its local clearing requirement," he said.

MISO fully expects to field more questions about Zone 7 at upcoming Resource Adequacy Subcommittee meetings, Thoms said.

"There's going to be a lot of speculation about what this means for Zone 7 this summer," Coalition of Midwest Transmission Customers attorney Jim Dauphinais said.

Before this year's Zone 7 price, the most expensive capacity price ever recorded in MISO was the \$150/MW-day in southern Illinois'

Zone 4 during the 2015/16 PRA. The price spurred allegations of market manipulation, a three-year FERC investigation and — five years later — a contested FERC assurance that nothing untoward occurred. (See [FERC Shelves Grievances over MISO Capacity Auction](#).)

MISO said auction results line up with its annual resource adequacy survey with the Organization of MISO States, which predicted adequate reserves through 2022 but warned that Zone 7, Zone 4, and Indiana and western Kentucky's Zone 6 have the risks. Last year's survey indicated a potential 0.9-GW shortage in lower Michigan in 2020. (See [Supply Future Brighter, OMS-MISO Survey Shows](#).)

The RTO said conventional generation will provide about 80% of capacity this planning year. Coal is set to provide 34% of capacity, while natural gas will provide 38%. Nuclear generation again holds steady around 9%.

However, MISO said renewable capacity continued to gain market share. It reported 850 MW of solar generation cleared this year's auction — an increase of 25% from last year — and 3,275 MW of wind generation cleared, a 21% increase. Demand-based resources also climbed, providing nearly 16 GW of capacity as compared to last year's nearly 15 GW.

The RTO said will publish the cleared load-modifying resources to the nonpublic MISO Communications System by May 25. ■

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MISO News

Local Projects Axed from MISO Cost Allocation Refile

By Amanda Durish Cook

MISO is mounting a third attempt to gain FERC approval of a plan to overhaul the cost allocation design for economic transmission projects after two previous rejections.

This time the RTO will eliminate the local economic transmission project category from its proposal, a sticking point in the earlier filings.

FERC rejected MISO's proposed cost allocation a second time on March 20, raising the same cost-causation issues that dogged the first filing ([ER20-857](#)). The commission took issue with MISO's proposal to measure the value of a local economic project on a regional basis but cost-share only locally. The local economic project category was intended for smaller, economically driven transmission projects between 100 and 230 kV, where 100% of costs would be allocated to the local transmission pricing zone containing the line. (See [Another Rejection for MISO Cost Allocation Plan](#).)

MISO said it will follow FERC's recommendation to refile the regional allocation without including the local economic project category.

MISO Senior Manager of System Planning Jarred Miland said it would likely take months for stakeholders to reach consensus on how to treat 100- to 230-kV economically beneficial projects.

"We want to get this thing done, get this thing out. We feel we have support right now on the

other parts," Miland said during a Thursday conference call of the Regional Expansion Criteria and Benefits Working Group.

As in the first two filings, MISO's newest proposal would lower the voltage threshold for market efficiency projects (MEPs) from 345 kV to 230 kV, eliminate the current 20% postage stamp allocation and add new benefit metrics for savings from the avoided costs for reliability projects and cost reductions related to the MISO-SPP transmission contract path. The proposal will also provide limited exceptions to the competitive bidding process if a transmission project were needed immediately for the sake of reliability.

"Everything will be pretty much like it was in the January filing. It'll look pretty much the same; it just won't have the local economic project component to it," Miland said.

Clean Grid Alliance's Natalie McIntire asked how economically beneficial projects between 100 and 230 kV will be treated going forward.

Miland said such projects would again be relegated to MISO's "economic other" project category, which has no regional benefits test and dictates that smaller economically beneficial projects be allocated to the transmission pricing zone in which they are located.

However, he pointed out that the new lower voltage threshold for MEPs will most likely result in MISO approving more economic projects for cost-sharing.

Miland also said regional economic projects between 100 and 230 kV are rare in MISO.

"We haven't seen much below 230 kV in the past, so I doubt we'll see more in the future," he said.

MISO said it will resubmit its regional cost allocation filing by the end of the month or in early May.

Miland said MISO will not collect stakeholder feedback on the refile, added that FERC's direction was specific enough and the RTO's previous efforts have "already been a really, really long journey."

As with the first two filings, MISO will again include a promise to review the effectiveness of the cost allocation approach after three years.

SATOA Tech Conference Set

MISO faces another obstacle related to the allocation of transmission project costs: the lack of an approved cost recovery mechanism for its first storage-as-only-transmission-asset (SATOA) project.

FERC *scheduled* a May 4 technical conference to discuss possible shortcomings with MISO's SATOA proposal. (See [MISO SATOA Proposal Set for Technical Conference](#).) The commission said MISO officials should come prepared to answer several questions, including those regarding:

- the proposed evaluation and selection of SATOA as transmission-specific solutions;
- why SATOA shouldn't be allowed access to energy markets;
- how the existing formula rate provides a cost recovery process for SATOA;
- the possible impact of SATOA on the generator interconnection queue; and
- state-of-charge responsibility.

MISO's 2019 Transmission Expansion Plan (MTEP 19) contains the RTO's first-ever SATOA project — American Transmission Co.'s Waupaca-area energy storage project, intended to ease transmission reliability issues in central Wisconsin — which was withheld from final MTEP 19 approval as the RTO waited on approval for its proposed SATOA rules. MISO had planned to have its Board of Directors hold a special March vote on the project once it had FERC's go-ahead for its rules and cost-recovery method. (See [MTEP 19 Could Yield First MISO SATOA Project](#).) ■



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MISO News

MISO to File 1st COVID-19 Queue Waiver Request

MISO will ask FERC to waive a specific generation interconnection queue requirement to assist developers whose projects face construction preparation delays in the face of the COVID-19 pandemic.

The RTO will request a “limited FERC waiver” of its June 25 deadline for developers to demonstrate site control for projects entering MISO South’s 2020 interconnection cycle, Manager of Probabilistic Resource Studies Ryan Westphal told listeners on a Planning Advisory Commit-



Ryan Westphal, MISO |
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tee call Wednesday. MISO has not determined the length of the extension it will seek.

Westphal said the chief concern of most interconnection customers is how they will meet deadlines to show exclusive land use for generation projects during the pandemic. MISO’s next site control deadline doesn’t occur until September, when the 2020 MISO West batch of projects enter the queue.

“There’s still uncertainty of when some states and localities will lift restrictions,” he said. “We’re looking at the near future and can go back to FERC to extend waivers as necessary.”

Westphal said the request specifically applies to the site control deadline and would not affect other queue deadlines. However, he

said, additional waivers “are on the table” if the pandemic wears on and groups of interconnection customers encounter similar obstacles. (See [MISO Considers COVID-19 Queue Waivers](#).) “At least” two interconnection customers have reached out to MISO to discuss special circumstances affecting their projects, he said.

MISO will not hold a call to discuss the finalized filing with stakeholders and will file in the “next two weeks,” Westphal said.

Social distancing efforts have been skewing MISO load and planned outages since mid-March. (See [COVID-19 Transforming MISO Load, Outage Schedules](#).) ■

— Amanda Durish Cook

MISO Begins Bid to Merge Tx, Queue Planning

By Amanda Durish Cook

MISO staff will commence work on a project to better align generation interconnections and transmission planning after stakeholders retired the task team charged with suggesting ways to bridge the two processes.

Stakeholders created the Coordinated Planning Process Task Team in November to probe how MISO could increase coordination between the separate studies underpinning the RTO’s Transmission Expansion Plan (MTEP) and its generator interconnection queue process.

The team in February forwarded MISO’s Planning Advisory Committee and Planning Subcommittee a list of topics to address. (See [MISO Committees Tackle Queue, Tx Planning Disparities](#).) With the task list in hand, the PAC on Wednesday voted to retire the team during a teleconference.

MISO will now examine the two study processes as a first step in possibly unifying them. Senior Manager of Expansion Planning Edin Habibovic said the RTO would begin with “an in-depth review of MISO planning study objectives, methodologies and assumptions.”

“MISO believes it is prudent to review MISO’s planning processes, identify correlation and document rationale for any disparities between them,” Habibovic said during a Planning



| MISO

Subcommittee teleconference April 14.

Habibovic said the review will occur in planning meetings and special meetings scheduled through August.

MISO renewable proponents and some state regulators have repeatedly contended that the RTO unfairly relies on interconnection customers to finance increasingly expensive new transmission capacity under the pretext of network upgrades and may be neglecting its responsibility to get major projects approved in its transmission packages. Renewable advocates have questioned why interconnection studies show the need for expensive transmission upgrades when studies performed under the MTEP do not.

Stakeholders have [suggested](#) MISO better align the timelines of interconnection and MTEP planning and ensure the studies draw on similar data, including dispatch assumptions. The synchronization effort could have the RTO approving more transmission projects by MTEP 2021. (See [MISO Seeks Ideas for Streamlined Tx Planning](#).)

MISO is currently juggling 10 separate queue cycles among its four planning regions, with five additional cycles set to begin over the next year. Senior Manager of Economic Planning Neil Shah said the unusually high number of queue cycles being processed in unison will be an obstacle to aligning timelines with MTEP. ■

MISO News

Morenci Project Dropped from MTEP 18

FERC Says MISO Rightly Stayed Out of Debate

By Amanda Durish Cook

FERC last week affirmed that a small Michigan transmission project in MISO's 2018 Transmission Expansion Plan (MTEP 18) is in fact a local distribution facility that should not be included in the annual portfolio.

The ruling leaves no doubt that Michigan Electric Transmission Co.'s (METC) \$21 million, 138-kV Morenci line near the Michigan-Ohio border will be removed from MTEP 18 (EL19-59).

FERC in the same order also declined to launch an investigation into MISO's Tariff to find out whether the RTO should take an active role in determining whether particular projects function more as transmission or distribution.

Consumers Energy in April 2019 filed a complaint against MISO and METC, claiming the Morenci project was "improperly" included in MTEP 18 because it failed FERC's seven-factor transmission test. The utility asked FERC to

forbid MISO from approving the construction of a distribution facility. (See *Michigan Regulators Intercede in MTEP Complaint*.)

The Morenci project was intended to address anticipated load growth; METC submitted an expedited project review request to MISO for the project in 2018.

The Michigan Public Service Commission in November *determined* the line had more in common with distribution than transmission, dropping it from MTEP eligibility. FERC waited until Michigan regulators had concluded their investigation before it ruled on the matter.

The federal commission dismissed METC's argument that the line will be used to transport wholesale power, noting that although technically true, it wouldn't be the primary purpose of the line.

"The Michigan commission found that although wholesale transactions occur over the Morenci project, that does not mean that its function is a transmission facility; rather, the

function of the Morenci project is to deliver power leaving Michigan Electric's looped transmission system to Midwest Energy's distribution system for exclusive consumption by Midwest Energy's retail end users," FERC said.

Consumers also alleged that MISO should have performed a seven-factor test on the Morenci project before it included it in MTEP 18. The utility asked FERC to open an investigation into MISO's Tariff and determine whether the RTO should develop additional procedures to test transmission projects before they're included in an MTEP cycle.

The Michigan PSC also *asked* the commission to "determine if, and when, in the transmission/distribution classification process it would be appropriate for a utility or MISO to request a state commission determination of whether or not a project is transmission and, thus, eligible to be included in MTEP."

MISO maintained that the process is already clear-cut, placing the classification responsibility on transmission owners who "have the best knowledge of their own systems and facilities."

"It is MISO's role to evaluate transmission projects developed through its planning and stakeholder processes; it is not MISO's role to initiate hundreds of classification proceedings with state regulators or this commission," the RTO wrote in December.

FERC agreed with MISO's view and said the RTO made the right move when it largely kept itself out of the dispute and suggested the "parties request classification by an appropriate regulatory authority" once it saw the impasse.

The commission said it wouldn't entertain Consumers' request to investigate MISO's Tariff and recommend the RTO adopt additional procedures to test projects.

"We agree with MISO that the classification of assets of a regulated entity is a regulatory function that should be performed by the commission and state commissions and that requiring MISO to perform a seven-factor test for projects proposed during the MTEP process would be overly burdensome without providing significant benefit," FERC said.

"MISO only has authority to classify facilities for transmission owners that are not subject to regulation by a regulatory authority," it reminded Consumers. ■



Michigan Public Service Commission headquarters | Google

MISO News

FERC Tweaks Entergy Bandwidth Decision

Denies Rehearing on Control Centers

By Amanda Durish Cook

FERC on Thursday reversed one part of a previous decision on the long-disputed bandwidth calculation that Entergy last used more than five years ago to equalize production costs among its operating companies.

In response to the latest rehearing request in the ongoing proceeding — this time from the Louisiana Public Service Commission — FERC ruled that some tax gains from the Waterford 3 nuclear plant near New Orleans can be included in bandwidth formula accounts ([EL10-65-006](#)).

Before it joined MISO in 2015, Entergy's operating companies functioned as one system, although each had different operating costs. FERC in 2005 determined that production costs across the multistate Entergy system were not as equal as the company promised and imposed a bandwidth payment remedy, spurring a dispute that has lasted several years. Under the arrangement, Entergy's low-cost operating companies made payments to the highest-cost company in the system using a "bandwidth" remedy that ensured no operating company had production costs more than 11% above or below the system average.

Since then, the allocation of 2007-2015 production costs among Entergy's half dozen operating companies under its multistate system agreement has been a source of disagreement for a decade.

In a March 2018 ruling, FERC made three findings regarding Entergy's bandwidth equalization:

- that it properly accounted for the 9.3% interest sale and leaseback of Waterford 3 in its accumulated deferred income taxes (ADIT) when it characterized the sale as financing and excluded it from bandwidth formula payments;
- that Entergy could keep interruptible load in its system monthly coincident peaks used to develop the 2010 and 2011 bandwidth calculations, although all other years of Entergy's bandwidth payments exclude interruptible load; and
- that it appropriately accounted for the costs of the allowance for funds used during construction for the River Bend nuclear plant north of Baton Rouge in bandwidth payment



An Entergy control room at the Nelson coal plant site in Louisiana | Entergy

calculations. (See [FERC Affirms Ruling Favoring Entergy Bandwidth Calculation](#).)

FERC last week said it is now persuaded by the Louisiana PSC's argument that the tax gain portion found in Waterford 3's financing of ADIT "is directly related to amounts included in bandwidth formula accounts." The commission said the amount "is generally and properly includable for FERC cost-of-service purposes" and should be included in the bandwidth calculation.

However, FERC told the Louisiana PSC it wouldn't budge on its earlier decision to allow interruptible load to factor into the 2010 and 2011 bandwidth calculations but not any other years' calculations.

"We continue to find that the commission already resolved the interruptible load issue ... and that no further relief is available in this separate proceeding," the commission said.

Rehearing Denied on Entergy Control Centers Transfer

FERC also denied several rehearing requests over Entergy's two recently constructed transmission control centers in Jackson, Miss., and Little Rock, Ark.

In September, FERC authorized the ownership transfer of the control centers from Entergy Services to Entergy's Arkansas, Louisiana, Mississippi, New Orleans and Texas operating companies. (See [Entergy Control Center Ownership Changes OK'd](#).)

Multiple regulators in Southern states sought rehearing on the fairness of the transaction itself ([EC19-18-001](#)) and the joint ownership agreement ([ER19-211-001](#)).

The Louisiana PSC charged that FERC ignored the impacts to retail rates when it approved the transaction. The costs incurred to acquire the control centers will become an input into the Entergy operating companies' respective rate formulas.

But FERC denied the PSC's rehearing request, finding that while the transaction will increase rates, the rate impact isn't adverse. The commission said the transfer of the control centers is in the public interest because they contribute to the "safe and reliable operation of the Entergy transmission system." FERC also reminded parties that the reasonableness of the transaction's price impacts wasn't in question.

"The commission's Section 203 analysis concerning rate impacts of a transaction does not extend to retail rate impacts unless a state commission lacks the authority to review such rate impacts and specifically asks the commission to do so. We note that, although the Louisiana commission and the Arkansas/Mississippi commissions have intervened in this proceeding, they have not asked us to scrutinize such effects here. We also note that our approval of the transaction in this proceeding does not preclude the Arkansas/Mississippi commissions or the Louisiana commission from examining the transaction's effects on retail rates," FERC said.

MISO News

The commission also brushed aside Louisiana regulators' concerns that the transaction would alter its jurisdiction over Entergy. FERC said the state commission will continue to have the same regulatory authority over Entergy operating companies "before and after the transaction."

FERC rebuffed the Arkansas and Mississippi Public Service Commissions' concerns that Entergy Services acted as a public utility "without satisfying the requirements of a public utility" by constructing the control centers in the first place. FERC simply said the concerns were out of scope of the current docket.

"With regard to the claim that Entergy Services improperly transferred the facilities, we note that Entergy Services appropriately

sought the commission's approval of the transfer in this proceeding," FERC added.

As to the transaction agreement, the Louisiana PSC said it was unfair that the ownership interests of the two facilities would be divvied up according to the Entergy operating companies' coincident peak loads, claiming that Louisiana ratepayers were set to take on more costs stemming from the control centers. The state commission also claimed that an Entergy coincident peak is now meaningless because the Entergy companies "no longer operate as a system but are instead separate members of MISO, which has a different coincident peak."

FERC was not persuaded by either argument.

"The coincident peak load allocation method is

the traditionally approved method for allocating the costs of transmission facilities, and the historical and consistent use of this allocation method renders its choice presumptively reasonable," the commission said.

Finally, FERC also said the Louisiana PSC's concerns over the costs incurred to acquire the control centers is also outside the scope of the proceeding.

"As the commission explained in the agreement order, the costs incurred to acquire the control centers instead serve as an input to the operating companies' respective formulas, and the reasonableness of such costs for inclusion as an input to those formulas is not before us," FERC said. ■

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NYISO News



NYISO Weighs Market Options for Hybrid Resources

By Michael Kuser

NYISO on April 14 floated a plan that would provide hybrid storage resources (HSRs) three options for participating in its energy and capacity markets.

Kanchan Upadhyay and Amanda Myott, NYISO energy and capacity market design specialists, respectively, *presented* an overview of the plan.

“The project seeks to explore participation options for co-located, front-of-the-meter generators and energy storage resources,” Upadhyay told the ISO’s Installed Capacity/Market Issues Working Group during a teleconference. “And we have seen that some of the incentives, along with improvements in flexibility and availability, are motivating developers to couple generation resources with storage resources, so we expect more and more of these kind of resources in future.”

NYISO wants to see HSRs participate under existing market models as much as possible. While that may necessitate minor modifications to existing market rules, it would allow for quicker implementation of changes. If existing market rules need to be modified, such changes will be developed for a potential vote at the Business Issues Committee by the end

of 2020, Upadhyay said.

The ISO is proposing that HSRs participate as distinct generators (Option 1); through an aggregation model to allow resource components within the HSR to share a point of interconnection (2); or as a self-managed energy storage resource (ESR) (3).

Installed capacity (ICAP) and unforced capacity (UCAP) for each resource component under Option 1 would be calculated based on the existing method applicable to that resource type, noting that UCAP is calculated using the availability-based method for ESRs and the performance-based method for intermittent resources.

The ISO would calculate ICAP and UCAP under Option 2 using the availability-based method, consistent with existing distributed energy resource rules, in which the upper operating limit of the entire HSR would be used to measure availability.

Under Option 3, ICAP and UCAP would also be calculated using the availability-based method, but using the upper operating limit of the ESR asset within the HSR to measure availability.

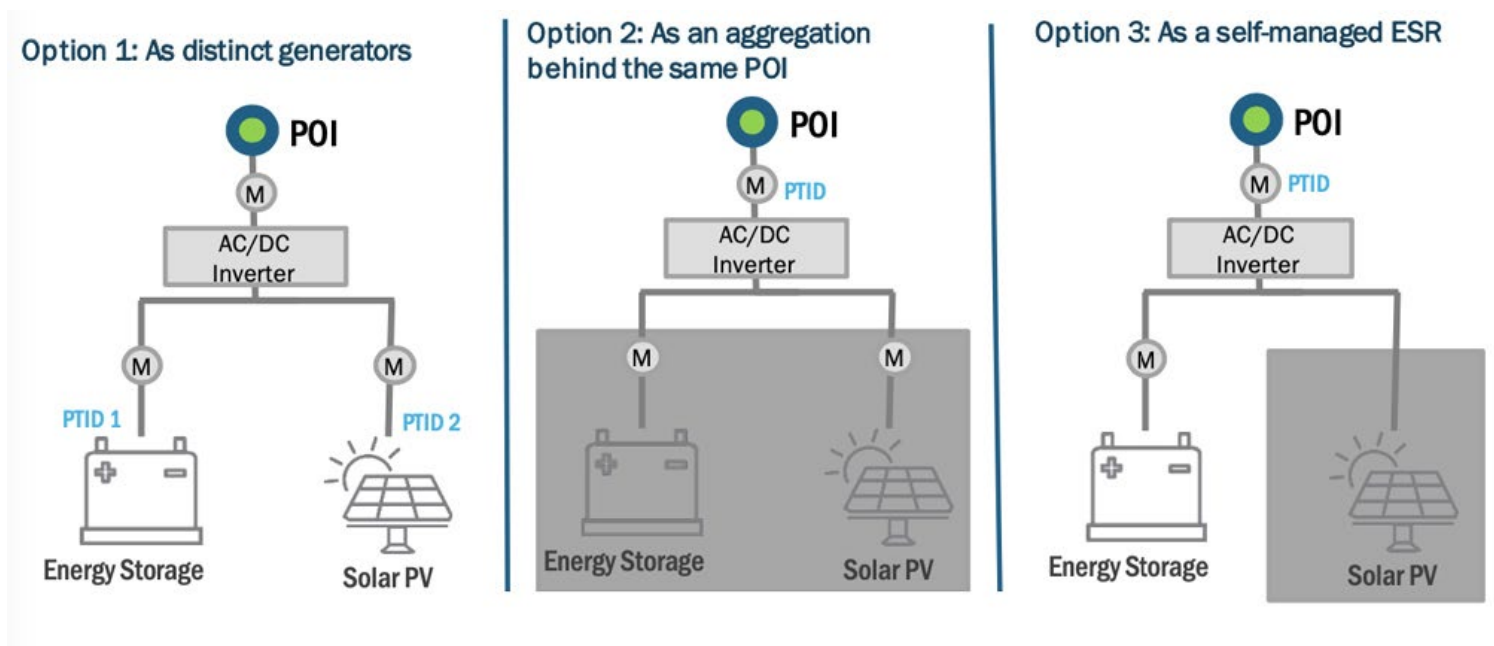
“There is no new option between deploying the ESR model and deploying the DER model,”

said Michael DeSocio, NYISO director of market design. “Option 3 is an extension of the ESR participation model, which could be introduced before [new DER rules] because it’s really leveraging the ESR rules, procedures and modeling.”

“We think Option 2 is one that could be implemented along with or just after DER because it is leveraging the DER rules, procedures and modeling,” DeSocio said. “We are not prepared to change Option 2 today to allow these resources to provide operating reserves, mainly because the [Northeast Power Coordinating Council] rules that determine which resources can provide which reserves are pretty stringent.

“We would have to work with NPCC to see if changing these rules is even possible to do, and I also believe the rules in the Eastern Interconnect are very different from the rules in the Western Interconnect, which is mostly why you see large differences in reserve participation modeling between California and New York,” DeSocio said.

The ISO plans to continue discussing and developing market participation concepts for HSRs this quarter and present consumer impact analysis and a complete market design to stakeholders in the third quarter, Upadhyay said. ■



HSR participation options under consideration by NYISO | NYISO

NYISO News

FERC Grants NYISO Public Power Definition Waiver

By Michael Kuser

FERC on Thursday granted NYISO a waiver of the Tariff language defining a public power entity, extending the definition to cover any government entity, regardless of whether it owns or controls distribution facilities and provides electric service (ER20-922).

The ISO in January requested the waiver of Section 26.5.3.6 of its Market Administration and Control Area Services Tariff in order to allow it to continue granting unsecured credit, up to \$1 million annually each, to government entities that do not meet the definition of public power entity.

NYISO also said it is working with stakeholders to revise the relevant definition and seek approval from the commission.

“NYISO acted in good faith because it did not intentionally disregard the limitations set forth in the currently effective definition of public power entity and ... took this self-correcting ac-

tion promptly upon discovering the limitation in its current definition,” the commission said.

The ISO said it extended unsecured credit to government entities, regardless of whether they own or control distribution facilities and provide electric service, based on a good faith understanding of how Section 26.5.3.6 should be administered in light of the credit profiles of government entities.

The commission also found NYISO’s waiver request was limited in scope, being in place for nine months and only involving a subsection of a definition, noting that the ISO said that it may not need the waiver for the full nine months.

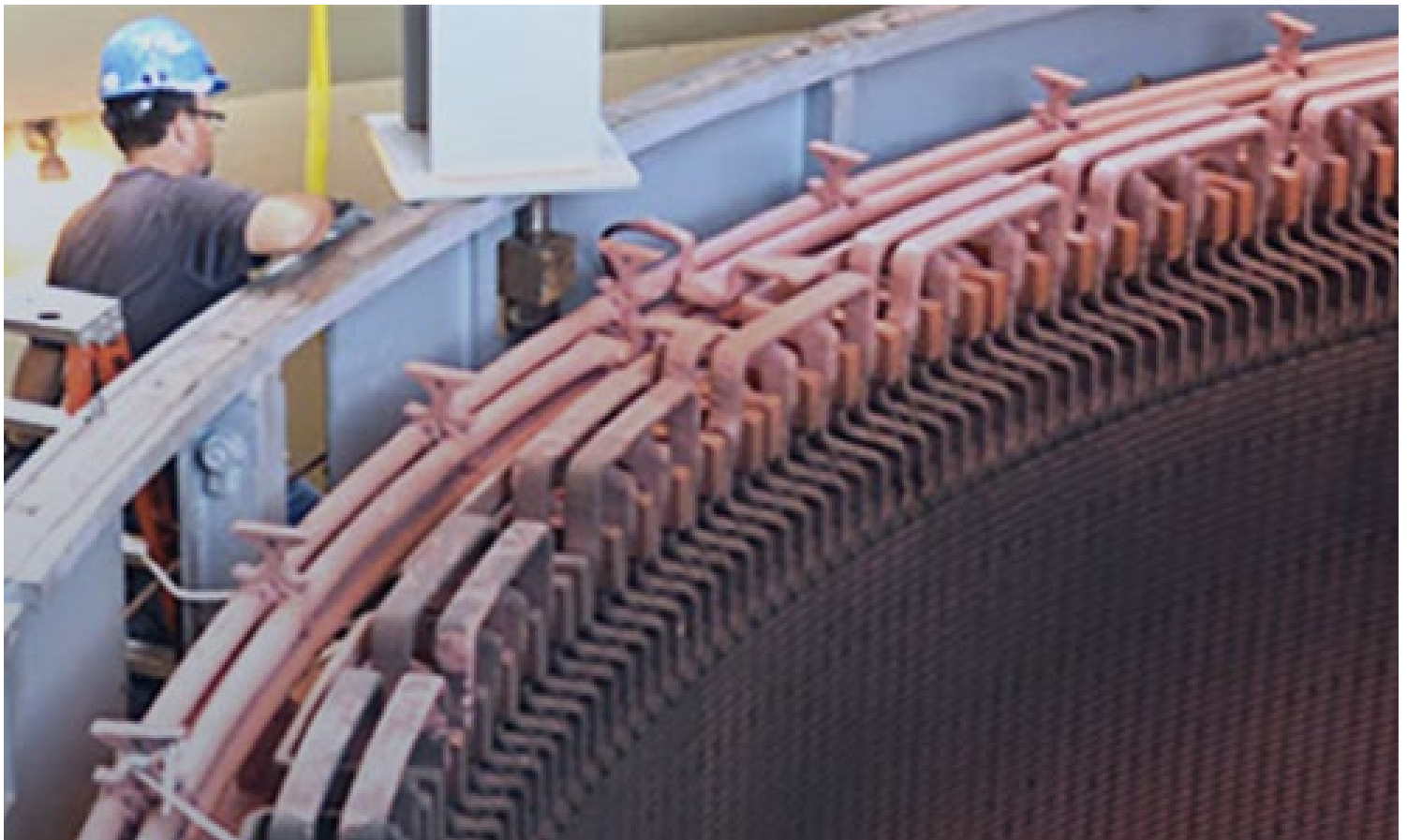
FERC said that granting the waiver will avoid needlessly creating practical business difficulties for certain municipal and government entities. It is also consistent with the underlying Tariff recognition that municipal entities generally do not present significant risk of nonpayment but are unable to demonstrate creditworthiness through conventional indica-

tors, the commission said.

NYISO identified 10 municipalities or other government entities that would be affected by the requested waiver, resulting in an extension of up to \$10 million in unsecured credit among them.

Finally, the commission found that the waiver request would not have undesirable consequences “because, as NYISO explains, there has not been any material increase to the financial risks of NYISO or other market participants, and denying the requested waiver could needlessly harm government entities that do not own or control distribution facilities and provide electric service.”

Given that the ISO admitted to having been violating the Tariff definition since as early as 2004, the commission said it would “exercise our discretion in addressing such matters and, given the facts and the record before us in this matter, take no action with respect to the instances of NYISO’s past noncompliance.” ■



Workers do maintenance on a turbine in a New York Power Authority project. | NYPA

NYISO News



NYISO Launches Fuel Security Effort

'Grid Transition' Discussion Continues

By Michael Kuser

A new initiative will aim to help NYISO improve its monitoring of fuel and energy security (FES) across the New York grid, stakeholders heard last week.

The effort comes after NYISO last year engaged Analysis Group to produce an FES study, which was posted in November along with ISO management's response.

The study's findings have prompted NYISO to include additional fuel security elements in both its winter capacity assessments issued each fall and cold weather operations presentations provided each spring, Vice President of Operations Wes Yeomans told the Installed Capacity/Market Issues Working Group during a teleconference April 14.

The ISO also plans to create forward load forecasts and possibly develop fuel-related "thresholds or triggers" to help identify potential future FES concerns.

NYISO will expand the outlook of its forward-looking, short-term internal operational assessments by an additional week to allow

for improved consideration of FES matters, Yeomans said.

"Certainly in the winter time frame, there's an opportunity for us to take a lot of those constructs from the FES study and do it internally when we do that weekly capacity review," Yeomans said. "Ultimately, that weekly internal review is intended to evaluate electric capacity sufficiency, out seven or 10 days, to meet the projected loads or peaks, and now we're going to extend the time frame to be 14-plus days."

Any large deviations in actual conditions versus the assumptions used in the FES study that impact reliability may trigger a need to refresh the study, he said.

"There are two categories of thresholds, or triggers, that may require a full-blown rerunning of the study," Yeomans said. "One would be if some set of variables change in a radical way; another one may just be that actual events don't play out as assumed. There may be less wind developed, or less solar gets developed, or maybe the offshore wind assumptions for Long Island get delayed by two or three years; maybe there's some accelerated retirements — there are a lot of variables that

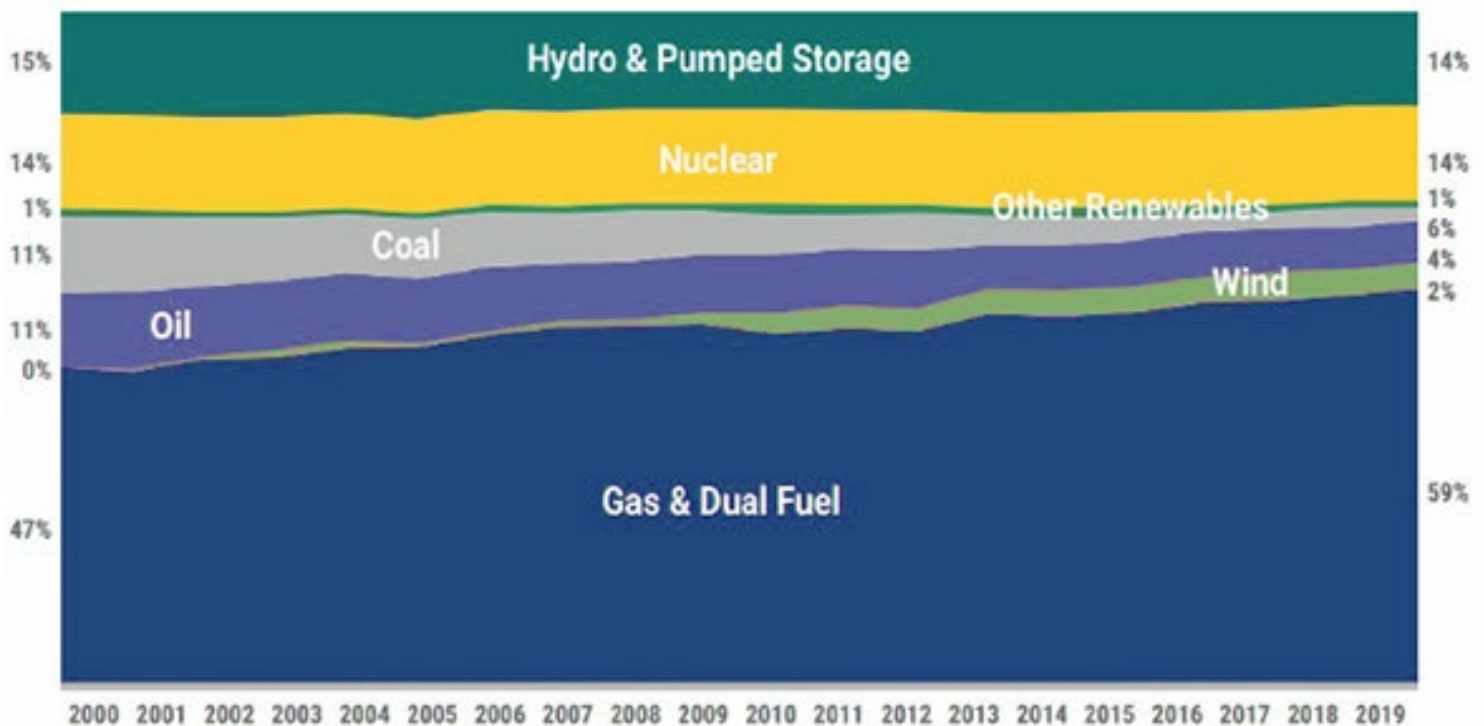
went into that study."

Luthin Associates' Aaron Breidenbaugh, representing a group of nonprofit institutional customers known as Consumer Power Advocates, asked "if the ISO has any process going forward for looking at the general reliability implications of the COVID-19 pandemic."

Yeomans responded that NYISO's operations department talks to the New York transmission owners every week to assess issues specific to the pandemic. NYISO says it "has communicated with generation operators to facilitate awareness of asset plans for ensuring continued operations and any concerns about impacts of COVID-19 on availability of critical staff."

"A lot of those discussions are more on critical employees than infrastructures, but we do talk about implications out in the field," Yeomans said. "If any TO was projecting implications with transmission capability transfers, whether Central East or otherwise, the NYISO would be informed of such conditions."

Regarding longer-term infrastructure enhancements, the ISO has to date not been



NYISO fuel mix | Analysis Group

NYISO News

informed of any projected delays in four large transmission infrastructure projects over the next couple of years, including public policy transmission projects, he said.

The latter include North America Transmission and the New York Power Authority building the double-circuit 345-kV line from Edic to New Scotland for Segment A of the AC Transmission Public Policy Transmission Need (PPTN), which feeds the Central East interface. National Grid's Niagara Mohawk Power and NY Transco are building Segment B of the project, a section of the grid feeding the Upstate New York/Southeast New York electrical interface. (See "AC Public Policy Tx Projects near Approval," *NYISO Management Committee Briefs*: Feb. 27, 2019.)

In addition, NYPA has a couple big projects of its own, including rebuilding and upgrading the existing 230-kV lines from Messina to National

Grid's Adirondack substation, Yeomans said.

NYISO will return to stakeholders in fall 2020 to discuss enhanced fuel security findings as part of the 2020/21 winter assessment, he said.

Planning the Future Grid

Energy market design specialist Ashley Ferrer led a discussion of the ISO's "Grid in Transition" initiative, focusing on nine areas of market design that the ISO believes merit "immediate attention."

Stakeholders last month began exploring detailed assumptions and models to be included in a Brattle Group study on transitioning New York's grid to cleaner resources. (See *N.Y. Looks at Grid Transition Modeling, Reliability*.)

The ISO recommends that it implement market design changes through 2024 regarding car-

bon pricing; comprehensive mitigation review; participation models for distributed energy and storage resources; enhancing energy and shortage pricing; energy and ancillary services product design review; enhancing resource adequacy models; revising resource capacity ratings to reflect reliability contribution; and adjusting capacity demand curves.

"Some of these recommendations do have projects that are current, mainly in the operating reserves portion, but some of them do not have projects," Ferrer said. "The purpose of going through these is to understand what some of these market design recommendations are, and if there are specific ones that project ideas come from, then that is something that we'll work into the normal project prioritization process."

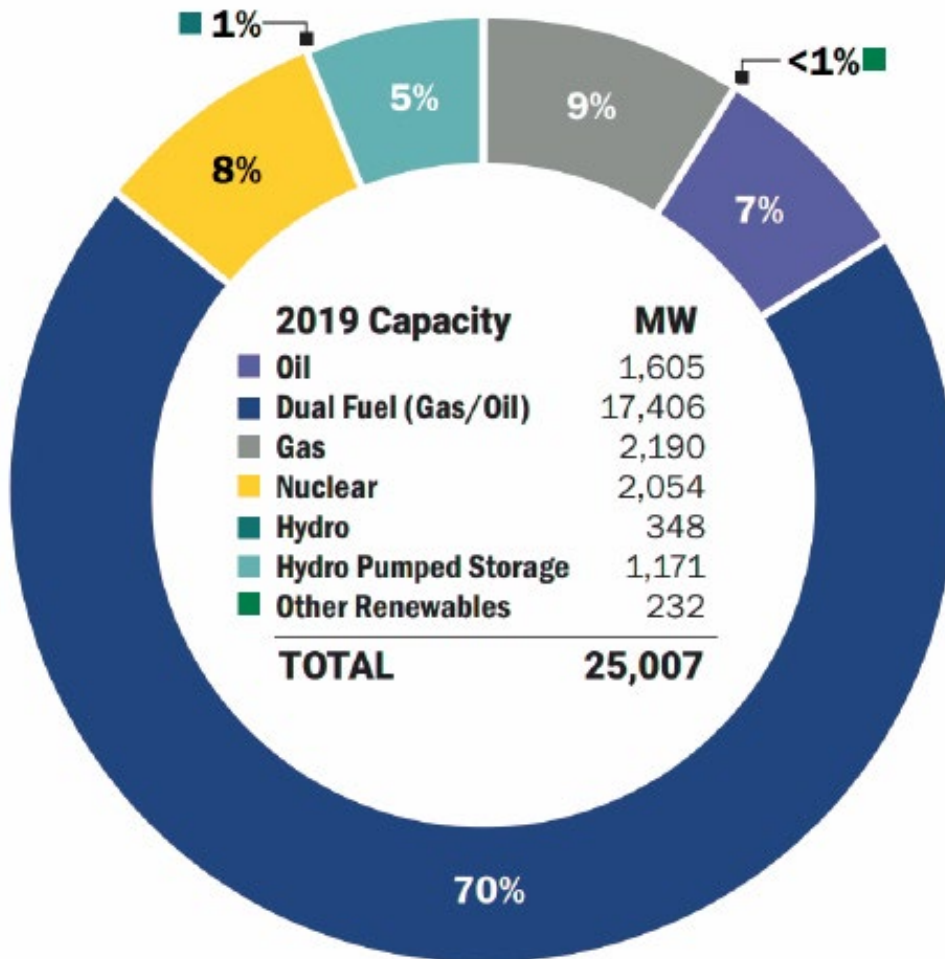
New York lawmakers this month passed a budget amendment to speed up the permitting and construction of renewable energy projects in order to meet the state's ambitious clean energy goals, which are driving the grid transition. (See *Cuomo Proposes Streamlining NY's Renewable Siting*.)

A reliability gap assessment identified potential high-level market design concepts for existing and potential future components of NYISO's markets, which the ISO divided into two categories: ancillary service products and energy market mechanics.

"When you've identified a potential reliability gap, there still may be multiple different ways of closing that gap and addressing the issue," said Couch White attorney Michael Mager, who represents Multiple Intervenors, a coalition of large industrial, commercial and institutional energy customers.

Referring to the ISO's standard approach of conducting consumer impact analyses only after a specific proposal has been finalized, Mager said, "We may get some idea of what the impact of the proposal is compared to the status quo, but we don't really get any type of analysis of maybe three or four different ways to skin this cat, and these are the differing economic impacts associated with each of the options. I'd like the NYISO to bear this in mind as it starts developing potential proposals or market rule changes."

NYISO will present on interregional coordination May 11 and is planning two additional presentations, tentatively for next month, to provide in-depth analysis of the market design components addressed. Planners by June will also present an overview of recommendations related to the ISO's operations processes, Ferrer said. ■



New York's 2019 downstate generating capacity, Zones F-K | Analysis Group

NYISO News

NYISO Management Committee Briefs

COVID-19 Impacts on Operations, Load

NYISO's Management Committee on Wednesday saw graphic evidence of how the COVID-19 pandemic response is impacting power demand and heard how the ISO's operations team continues to be sequestered at the two control centers, alternating shifts.

"Even though they were sequestered on-site, we didn't take for granted that they weren't infected, so after a 14-day period we allowed them more liberty to move around the site," NYISO CEO Rich Dewey said.

"We're almost exclusively working from home, except for the operators," he said. "We still have to run operations and issue invoices, so from a business process viewpoint, I'm happy to report that's all going very well. I'm happy to report that we have not experienced any operational issues yet."

Demand Forecasting Manager Charles Alonge [presented](#) estimated impacts of the pandemic on NYISO demand.

"We saw approximately a 4% drop in daily energy across the New York Control Area for that first week," Alonge said. "Moving into the second week of the shutdowns, we saw the

decline grow to about 8% during the week beginning March 22, and then the last week, March 29 through April 4, stayed the same at about an 8% decline."

The week ending April 11 saw a further 1% decline in load, to 9% below the expected levels, he said.

The same energy information plotted on daily, regional and NYCA bases showed varied regional impacts.

"The biggest impact on load was seen in Zone J, New York City, and Zone J also has the largest commercial percentage of load in the New York Control Area," Alonge said. "The biggest signal that we have observed with respect to demand impact is the morning ramp, which is lagged against where we expect it to be, and also the morning peak for this time of year is delayed."

Budget Precautions

The committee approved a staff [proposal](#) for the ISO to retain \$6.4 million remaining from the 2019 budget cycle to potentially offset a shortfall in 2020 Rate Schedule 1 (RS1) recoveries and unplanned expenditures resulting from the pandemic.

The NYISO Board of Directors will vote on the budget proposal at its meeting this week.

"If we do find that these funds are not needed for the estimated budget shortfall, we still will have the opportunity to pay down principal on outstanding debt in the fourth quarter of 2020," CFO Cheryl Hussey said.

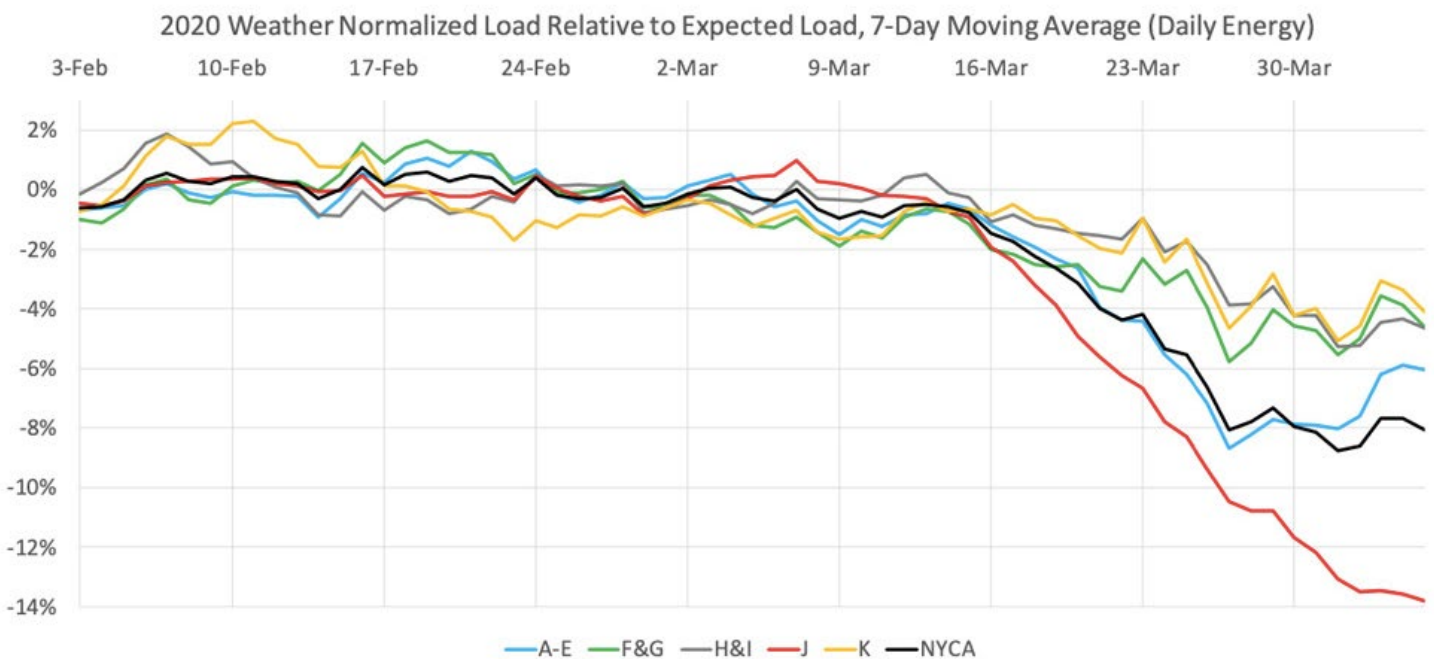
The recommendation was discussed with market participants at the Budget and Priorities Working Group meeting March 31 following completion of NYISO's 2019 financial statement audit.

The 2019 \$6.4 million budget surplus stems from a RS1 overcollection of \$700,000 combined with a spending underrun of \$5.7 million.

ESR Scheduling Performance Proposal

The MC approved a proposal to resolve scheduling performance issues related to energy storage resources (ESRs).

Michael DeSocio, NYISO's director of market design, presented a proposed Tariff revision that would allow the ISO to provide stakeholders advanced notice of performance concerns no later than 4 p.m. on the day before day-ahead bids must be submitted for a day-ahead market (DAM) day.



Level of decline is proportional to commercial percentage of load in region

NYISO News



The Tariff provision also would suspend the use of ISO-managed energy levels with DAM offers until the performance concerns have been addressed.

The Tariff change will be bundled with other ESR revisions and voted on by the board this week ahead of filing with FERC later this month.

Enhancing Mitigation Rules

The MC also approved a fast-track approach for the ISO's proposal to revise its buyer-side mitigation (BSM) Part A exemption test based on the Market Monitoring Unit's two-pronged recommendation as part of the 2020 Comprehensive Mitigation Review (CMR) project. It recommended that the board approve measures for filing with FERC so that the changes could be used for the current class year.

ICAP Mitigation Engineer Christina Duong presented the CMR project [overview](#), saying the goal is to complete a market design this year, and that revisions to the Part A test are part of BSM enhancements.

NYISO's BSM rules provide that, unless exempt from mitigation, new installed capacity (ICAP) suppliers in mitigated capacity zones may only participate in the ICAP spot market auctions at a price at or above the applicable offer floor until their capacity clears 12 months (not necessarily consecutively).

FERC in February narrowed the resources exempt from NYISO's BSM offer floor determinations in southeastern New York, ordering the ISO to subject storage and special case resources to a minimum offer floor in its capacity market ([EL16-92](#)). (See [FERC Narrows NYISO Mitigation Exemptions](#).)

Prong 1 of the CMR involves changes to the parts A and B exemption tests such that public policy resource (PPR) examined facilities would be placed in the supply stack before non-PPR ones. Projects currently go in the supply stack from lowest to highest net cost of new entry.

"This change will allow legitimate PPR supply resources to be awarded a Part A exemption before non-PPR resources that may be less expensive but do not further the state's policy objectives," Duong said. "This is an incremental improvement as part of that larger goal, but we still may revisit the Part B mitigation study period as well."

"Among the stated goals in doing this [CMR] was to help enable the state's achievement of the recently enacted climate act," said Howard Fromer, director of market policy for PSEG Power New York. "In a related vein, earlier this week there was a petition filed at FERC seeking a technical conference on carbon pricing and pointing to all the extensive work that NYISO has done." (See related story, [IPPs, Renewable Groups Seek FERC Carbon Pricing Conference](#).)

Addressing Dewey, Fromer said, "If you haven't seen the petition, I encourage you to do so, and I hope the New York ISO would be supportive of that request. It's not asking for a rulemaking; it's asking for just a technical conference to discuss these issues ... and hopefully put in a filing at FERC indicating you would support this technical conference and participate in one."

"I read [the petition] earlier this morning, and I absolutely would support any open discussion that supports the advancement of carbon pricing," Dewey said. "The New York ISO continues to be very supportive of New York state's goals. ... The pandemic aside, we do recognize that the clock is still ticking on the achievement of these goals and the timeline it's going to take."

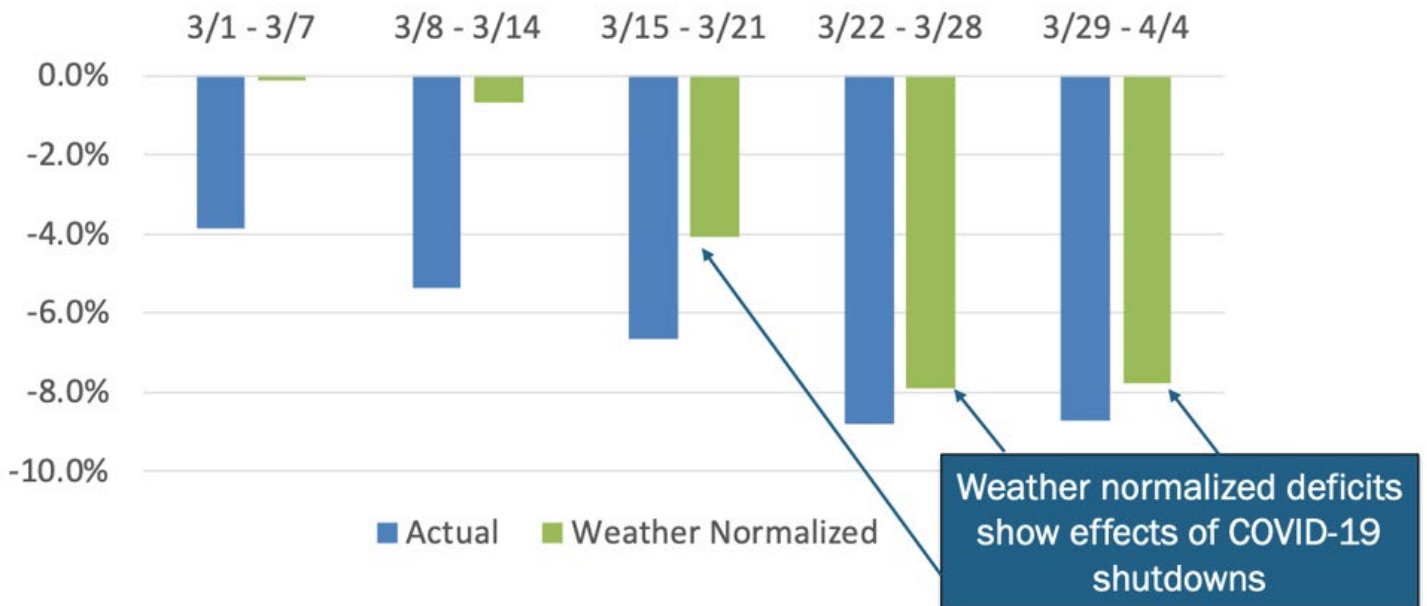
Fromer said he hoped that Dewey would share his support with FERC.

"Yes, I have personally told that to each of the FERC commissioners, and at the next opportunity I'll reiterate it," Dewey said. "We still think [carbon pricing] is the most effective, efficient means for the state to achieve its goals."

The Climate Leadership and Community Protection Act ([A8429](#)), signed into law last July, calls for 70% of New York's electricity to come from renewable resources by 2030 and for electricity generation to be 100% carbon-free by 2040. ■

— Michael Kuser

Weekly Energy Use -% Versus Expected



Recent impacts of COVID-19 on daily energy by week | NYISO

PJM News



Stakeholders not Sold on PJM SATA Plan

By Michael Yoder

PJM stakeholders last week questioned the scope and timing of the RTO's proposed initiative for considering storage as transmission assets (SATA) in the Regional Transmission Expansion Plan (RTEP) process.

The RTO is hoping to develop rules by the end of the year for treating storage that would be dispatched to address thermal, voltage or stability violations or to relieve transmission constraints. Other potential uses for SATA include operational performance (mitigating real-time violations not identified in planning studies) and public policy (grid enhancements requested by a state to further its policies).

PJM's proposed *issue charge* says it is seeking "transparent rules for stakeholders to understand how PJM evaluates these assets as opposed to an *ad hoc* evaluation process to evaluate SATA proposals submitted to mitigate baseline RTEP violations."

During a first read of the RTO's *SATA plan* at the April 14 Planning Committee meeting, Adrien Ford of Old Dominion Electric Cooperative (ODEC) expressed concern that the issue charge states that "PJM needs to initiate a stakeholder process" to add the SATA category.

'Bias Toward Change'

"We often have a bias toward change" instead of giving proper weight to the status quo as an equally viable alternative, she said.

Ford said she hopes PJM and its stakeholders determine whether planning rules require



Marji Philips, LS Power | © RTO Insider

changes and SATA resources are appropriate for transmission. She said ODEC believes that guidance from FERC on the issue is needed, as the current definition of transmission doesn't include SATA.

"It really seems as though PJM has come to the foregone conclusion that we should have storage as a transmission asset," Ford said. "FERC really needs to answer the threshold question on whether storage should or shouldn't be defined as a transmission asset."

Marji Philips, LS Power's vice president of wholesale market policy, said the timing of PJM's proposal was "aggressive" because FERC will be presenting information on SATA in upcoming months that could potentially be utilized in the planning.

FERC has scheduled a technical conference for *May 4* on MISO's storage as a transmission-only asset (SATO) proposal. The commission ordered the hearing last month, accepting MISO's bid to include storage options in its annual transmission plan but suspending the new Tariff provisions until Aug. 11 after determining whether they might be "unjust, unreasonable, unduly discriminatory or preferential" (ER20-588). (See [MISO SATOA Proposal Set for Technical Conference](#).)

The commission has also scheduled a conference on hybrid storage and generation resources for *July 23* (AD20-9). (See [FERC Sets Tech Conference on Hybrid Resources](#).)

Philips also contended that evaluating the cost determination methodology for SATA should not be included in the scope of the proposal until it is decided "there is a separate and unique role" for battery SATA. She said SATA could be ruled to be a hybrid asset, making it subject to existing generation rules.

Independent Market Monitor Joe Bowring called the issue charge a "very significant change," citing several concerns, including why it makes sense to allow transmission companies to treat a type of generation asset as a cost-of-service transmission asset that would compete with market assets owned by competitive companies. "Is it reasonable to have regulated assets competing directly with competitive assets?" Bowring asked, while also questioning whether battery projects treated as transmission would be open to competitive bidding.

"If you're really going to evaluate this, you have to do it comprehensively, and you can't do it



Adrien Ford, ODEC | © RTO Insider

piece by piece," Bowring said. "As the proposal is written, other market-based generation assets could be treated as transmission assets by transmission owners."

Sharon Segner, vice president of LS Power, suggested that the issue charge or *problem statement* should address whether SATA is an appropriate policy to tackle. Segner previously raised questions about a proposal from American Electric Power to use storage to correct repeated outages on its Falcon-Prestonsburg 46-kV circuit ([AEP-2018-AP010](#)). Segner said PJM cannot include non-transmission alternatives such as storage in the RTEP until it has been designated as transmission by FERC. Allowing AEP to win approval of the project under the M-3 process — which is limited to TOs — discriminates against non-TOs, she said. (See [LS Power Challenges PJM on MEP, SATA](#).)

Dave Mabry, representing the PJM Industrial Customer Coalition, questioned the RTO's proposal to rule issues over dual usage — considering storage both as transmission and as a market participant — out of scope.

Looking for Gaps

PJM's Jeff Goldberg said the RTO's plan is intended to evaluate business rules and assess opportunities for the technology. "We want to explore the existing rules and performance measurement and methodology and look for gaps and opportunities in those in order to integrate storage transmission assets," Goldberg said.

The key work activities and the scope high-

Continued on page 31

PJM News



PJM, IMM at Odds on 5-Minute Dispatch, Pricing Rules

By Rich Heidom Jr.

PJM backed off plans to seek a vote next month on short-term changes to its *five-minute dispatch and pricing* procedures after pushback from the Independent Market Monitor and stakeholders.

PJM’s Tim Horger told the Market Implementation Committee on Wednesday that the RTO was prepared to make manual changes detailing short-term changes but needs more time to evaluate the operational benefits and impacts of long-term changes it has been discussing with the Monitor.

Horger said the short-term changes comply with FERC’s January ruling holding PJM’s fast-start pricing compliance filing in abeyance until July 31 to give the RTO time to resolve pricing and dispatch misalignment issues. FERC agreed with the Monitor, state commissions and consumer advocates, who argued that PJM uses different market intervals to calculate prices and dispatch, meaning resources’ compensation doesn’t correspond to their dispatch instructions. (See *FERC Stalls PJM Fast-start Compliance Filing.*)

The commission ordered PJM and NYISO a year ago to revise their tariffs to allow fast-start resources to set clearing prices. (See *FERC Orders Fast-start Rules for NYISO, PJM.*)

PJM’s proposed short-term fixes would align the locational price calculator (LPC) to use the reference real-time security-constrained economic dispatch (RT SCED) case for the same target time. LPC would calculate prices for the interval from 11:55 a.m. to 12 using the RT SCED solution for a 12 p.m. target time.

The RTO would execute LPC cases every five minutes after the start of a dispatch interval, using as inputs resource offers, parameters and ancillary service assignments for the interval ending at the target dispatch time. Offers for 11 to 12 would be effective up to and including the 12 p.m. target; offers for 12 to 1 p.m. would be applied to a dispatch target of 12:05.

Horger said PJM also has committed to conduct operator training and make software changes to limit automatic execution of RT SCED cases to once for every five-minute target time. Additional cases may be manually executed and approved as needed by dispatch-

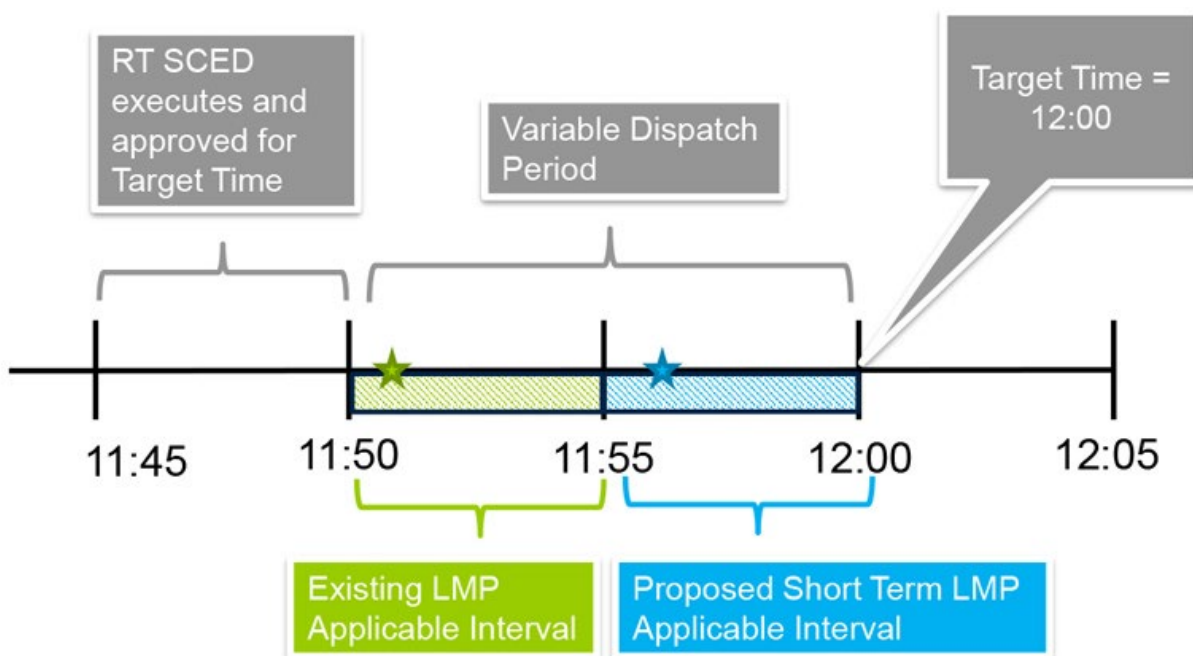
ers under what PJM calls this “intermediate” change.

The long-term changes would include auto-execution of RT SCED cases every five minutes with a target time of 10 minutes into the future.

If dispatchers do not manually approve an RT SCED case for a target time, a case would be automatically approved before the start of the dispatch interval. It would also add transparency when cases are not approved for a target time because of data errors or software failures.

Horger said PJM wants to prioritize and consider parallel or incremental implementation of the long-term changes. “It might look good on paper, but until we get a comfort level on an operational level, we can’t commit to it.”

IMM Joe Bowring said the Monitor thought it had reached an agreement with PJM following “months of productive discussions” on a compromise that would give dispatchers better information closer to the dispatch time and help ensure consistency between dispatch and pricing.



- ★ Existing LPC case execution time
- ★ Proposed LPC case execution time

PJM News



But he said the RTO posted a *presentation* and a proposal *matrix* the night before the meeting that indicated the RTO no longer supported the agreement. The RTO's current long-term proposal "is vague at best and probably years away," he said.

In addition to aligning pricing and dispatch, Bowring said in an email later, it also is essential to reduce "the RT SCED dispatch interval from 10 minutes to five minutes, running RT SCED on a regular five-minute interval to match the pricing interval to minimize running multiple RT SCED cases and changing dispatch instructions for the same target time, and using the prior RT SCED case as inputs to the current RT SCED case."

"Our goal continues to be a single comprehensive package," he said at the meeting. "We believe the entire package is needed to make SCED and LPC work consistent with the FERC order ... and it's really required for fast-start pricing to work correctly."

"This is something we're going to need to test. It requires operator training," responded Horger. "It won't be years away. It will be a lot closer than that."

PJM says the long-term changes may require a revised approach to ancillary service products.

"If we slow down the dispatch, [our concern is] what other compensating measures we [might]

need to take," explained Adam Keech, PJM vice president of market services. "Do we need more regulation if we slow down the dispatch? Sitting here today, I don't know that we know the answer to that."

Bowring noted that PJM recently changed the automated case execution for SCED from three to four minutes without operator training. "I don't know why training is needed to go from four to five minutes," he said.

Keech said the RTO believes the intermediate and long-term changes aren't required by the FERC order because they are not used "uniformly" in other RTOs/ISOs. He acknowledged that the recent change in the automated SCED case execution from three to four minutes has not caused any operational issues.

But he said that shift still allowed dispatchers to manually order additional cases in response to changing conditions. Preventing dispatchers from such manual intervention "is much different than where we are today," he said. "TBD on an exact timeline, but I will say there is motivation to make the change quickly, but I will add, judiciously."

Keech also said PJM's long-term goal is to greatly reduce dispatchers' interventions while retaining operators' ability to approve SCED cases if, for example, they unexpectedly lose a large generating unit. "The desire is not to

[intervene] unless it's absolutely necessary."

He said about one-third of approved RT SCED cases do not set prices currently because they are supplanted by new cases.

One stakeholder representing a trading firm who said he was not permitted by his company to be quoted by name said PJM's current practices are preventing proper transient shortage pricing even when the system is in a "critical state."

He cited a spinning reserve event in February that resulted from an under-forecast for load, an incident in October in which load rose faster than forecast and a July 2018 time error correction at noon and subsequent unit trips that resulted in a drop in system frequency on the Eastern Interconnection.

MIC Chair Lisa Morelli concluded the discussion by saying the committee will hold a second first read of the proposal in May. "I think it's pretty apparent we're not ready to move this to a vote at the next meeting," she said.

In the interim, the MIC will hold a special *meeting* on the issue May 1.

Horger said that because the short-term changes only affect the manual and do not require FERC approval, the delay should not prevent the RTO from making the changes by July as planned. ■

Stakeholders not Sold on PJM SATA Plan

Continued from page 29

lighted by Goldberg in Phase I of the process included ensuring the planning criteria address both performance measurement and cost measurement methodologies while also reflecting system operations input to maintain reliability.

The issue charge also calls for development of criteria regarding the size of SATA projects, including peak load, load duration and recharging characteristics.

It also would develop a framework for comparing storage to traditional transmission reinforcements.

Goldberg said modeling processes will be a key element to the project to address a storage asset's state of charge (injecting power to the grid, recharging or standing by for deployment). PJM wants to be able to conduct

sensitivity analyses to expose any reliability deficiencies.

Finally, PJM seeks to evaluate the methodology for determining the total cost of SATA facilities. The methodology would include an initial cost and ongoing maintenance cost; the life expectancy and cost to ensure usable life compared to traditional transmission assets; the consideration of losses associated with charge and discharge cycles; and comparability to existing transmission reinforcement.

"The idea is we want to formalize these as a proposal by taking all those concepts together," Goldberg said.

Phase 1 of the proposal was not intended to address issues associated with storage as a market participant, Goldberg said, because the terms "energy storage resource" and "capacity storage resource" are already in the Tariff.

Also out of scope for Phase 1 are operational mechanics such as model and telemetry requirements.

PJM's Aaron Berner said the issue charge is centered on examining PJM's requirements in relation to the RTEP and how storage could be used as "reinforcements" in meeting compliance obligations.

"In the end, that's what this effort at this phase is about: Can PJM accept a storage resource as a mitigation project for any of our compliance obligations?" Berner said. "If we can't get past that issue, we don't feel that there's any discussion around whether or not these facilities might be used for any dual use."

PC Chairman Dave Souder thanked the stakeholders for their feedback and said the committee would discuss the issue further at its May meeting. ■

PJM News



'Most Efficient' Coal Plant in Bankruptcy Again

Low Gas Prices, Mine Closure Hurt Longview Plant

Continued from page 1

cycle gas turbine (CCGT) plant and a 70-MW solar farm. Keffer noted, without apparent irony, that the additional generation would increase revenues “at lower fixed costs per kilowatt” than the coal plant.

But Keffer insists that the coal plant isn't a white elephant. “Despite recent trends, the PJM region requires a dependable coal-fired option in place for when energy demands inevitably increase. At times of national crisis, dependable utilities are at their most essential, and one key feature distinguishes coal from other existing energy sources — it can be stored.”

The \$2 billion plant in Madsville, W.Va., was “the first clean coal facility,” Keffer said, with equipment designed to be “one of the most environmentally compliant and cleanest coal plants globally.”

With an 8,750-Btu/kWh heat rate, 20% more efficient than older technology coal plants, “Longview is the future of coal,” the company's [website](#) boasts. Indeed, Energy Secretary Rick Perry deemed it so in a 2017 [visit](#).

But after two bankruptcies, does Longview have a future, or are the plant's owners whistling past the graveyard? And what do its struggles say about the fate of the nation's less efficient coal-fired generators?



Planned solar and combined cycle expansion at Longview Power plant | Longview Power

Michelle Bloodworth, CEO of coal trade group America's Power (formerly the American Coalition for Clean Coal Electricity), said wholesale markets are failing to compensate coal plants for their resilience and fuel security attributes.

“The exorbitant support in the form of subsidies, over \$100 billion, that renewable sources of electricity have received over the past several decades has only further distorted the electricity markets,” she said. “We remain concerned that unless action is soon taken to address these flaws, more coal plant owners could be in the situation that Longview Power is in — which will mean we risk further loss of

an important piece of a diverse electricity grid.”

Star-crossed

Longview has had a star-crossed history.

The plant was designed with infrastructure to allow for development of a second “clean coal” generator, including a 4-mile-long conveyor belt to carry coal to the plant from a nearby mine owned by a Longview subsidiary, Mepeco Holdings.

But when the plant went into operation in 2011 following construction delays, unscheduled outages and extended planned outages left the plant running at a capacity factor of only 68%, well below its design level of 90%.

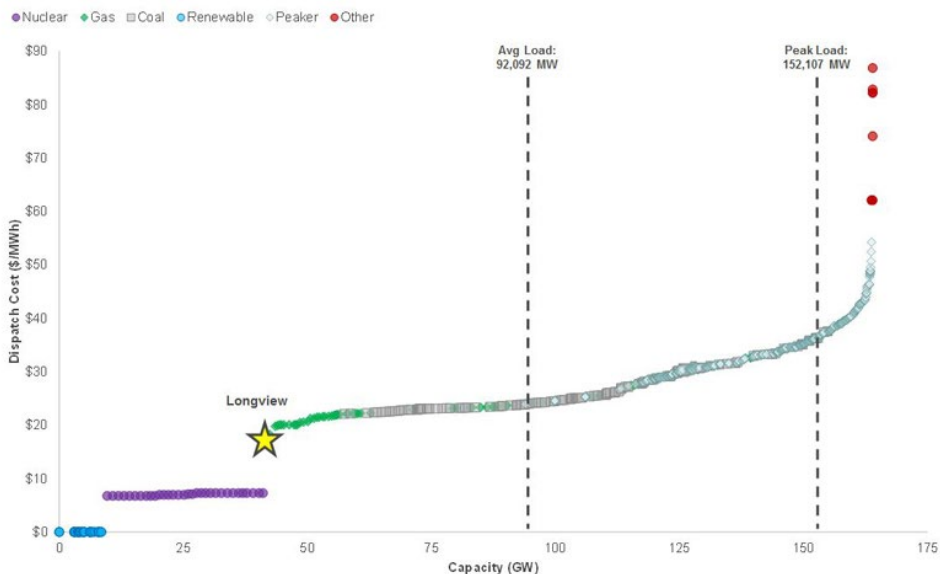
Longview began a multiyear arbitration with its building contractors; unable to repay a \$1 billion loan that helped fund construction, it filed for Chapter 11 protection in August 2013.

It emerged from bankruptcy in April 2015, with the company winning repairs to the plant and a \$325 million loan as the original lenders took all the equity in the reorganized company.

Since the repairs, the plant has generally operated at its design levels, Keffer said.

But it was saddled with high financing costs, including a \$30 million senior note at 12%. Then, in 2018, Mepeco discontinued operations at all of its mines, including the one supplying Longview, *citing* “the aging of the mine and adverse geological conditions” that reduced its productivity and made it uncompetitive.

With the 4-mile conveyor belt no longer of any use, the company spent \$8.3 million on a



Where Longview Power says it resides on PJM's supply curve | Longview Power

PJM News



dock on the Monongahela River to receive coal deliveries from other mines.

“Under normal operating conditions, the debtors’ steady cash flows enable them to reliably service their funded debt obligations and weather ordinary variations in customer demands, but recent extraordinary fluctuations in the energy market have presented the debtors with new balance sheet challenges,” the company said in its filing.

In addition to the “demand destruction” resulting from energy efficiency and warm winters in PJM, “the coronavirus pandemic has resulted in significant reductions in demand as industrial and commercial users are shut down throughout the region and country,” it added.

Although they designed the site to accommodate a second coal generator, company officials now say they will add a 1,210-MW CCGT and a 70-MW solar farm. “Realization of these development plans would provide operational and fuel diversity to help shelter Longview from the volatility of energy industry trends in the long term,” Keffer said.

Will the company get there?

Despite its efforts to reduce operating costs, renegotiate fuel contracts and seek cheaper financing, the company began “reviewing strategic alternatives” in January 2020. On March 31, the company and lenders reached a forbearance agreement on a \$750,000 amortization payment due that day.

With that breathing room — and facing the inability to pay off a \$25 million revolving debt that matured on April 13 — the company reached the prepackaged reorganization with

its lenders. Twelve investment funds currently own almost 96% of Longview Intermediate Holdings, the plant’s parent company, led by KKR Credit Advisors with 42%. *The Wall Street Journal* reported that KKR will lose nearly all of its ownership in the deal.

Keffer said the plan will allow “a comprehensive balance sheet restructuring that will reduce Longview’s debt burden, increase liquidity and send a strong message to Longview’s employees, vendors and other business partners that Longview is well positioned for future success.”

The deal will eliminate \$350 million of first lien and subordinated debt and provide the company a \$40 million “exit facility” loan from secured term lenders that will take a 90% stake in the reorganized company. It also allows “unimpaired” payments to unsecured creditors to ensure “minimal impact on the debtors’ operations and their key business partners.”

The company asked the court to have creditors vote on the plan by May 1 and schedule a confirmation hearing on May 22.

But even if all goes as planned, Longview faces a difficult future.

The Independent Market Monitor’s 2019 State of the Market report said only 26% of PJM’s existing coal fleet was able to recover its avoidable costs from energy, capacity and ancillary services revenue in 2019, down from 68% the year before. New coal plants have not received enough net revenue to cover their costs in any zone in the RTO since 2009, two years before Longview began operation.

Conditions have worsened this year with day-ahead electricity prices at the PJM West hub averaging \$19.83/MWh, a 47% drop from the \$37.48/MWh average in 2018 and 2019, the company said.

Keffer had expressed confidence during Secretary Perry’s 2017 visit that natural gas prices would rise once more pipelines are built to take it from Pennsylvania and West Virginia. “The world is clamoring for our natural gas,” he said. “Once they start consuming that gas, your supply is going to start matching that demand. So the price is going to go back up.”

Natural gas is currently selling at about \$1.40/MMBtu at the Dominion South hub, down from the \$2.65/MMBtu average in 2018/19, Keffer said. “The price of natural gas is even lower in the immediate area where Longview operates due to the presence of shale gas,” he added.

His filing includes a 13-week pro forma projecting the plant will generate \$20.3 million in revenue through July 10. Operating expenses of almost \$25 million will leave it with a negative cash flow of \$4.6 million for the period.

Expansion Plan

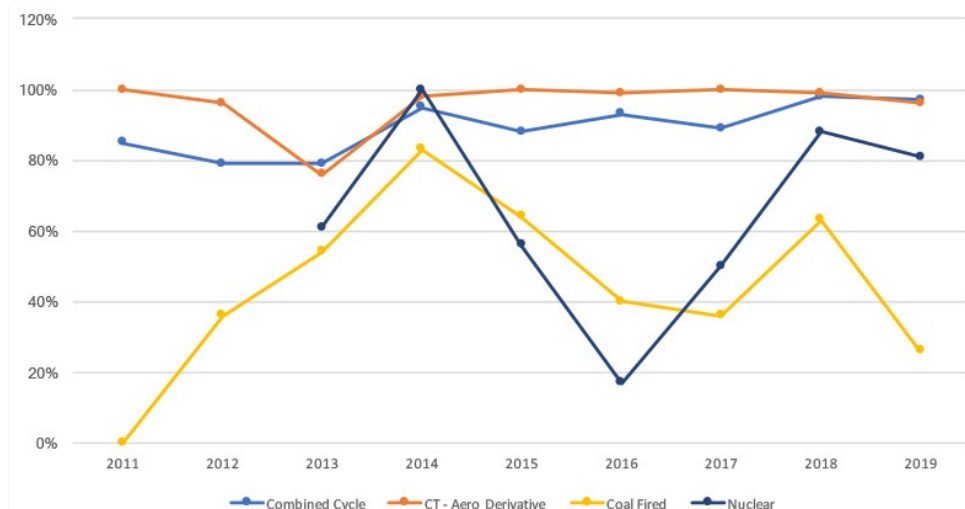
On the positive side, Longview said it will be able to add the combined cycle plant at \$200 million less than the cost competitors would have to pay for a comparable new build in PJM, thanks in part to the Dunkard Creek water treatment facility, which can serve both Longview and the CCGT project.

Permitting for the CCGT project is expected to be completed during the first quarter of 2021.

The solar project would involve 188,000 370-watt panels over 300 acres in Madsville and Greene County, Pa. The solar project will include the laydown areas for the CCGT project — the areas used for receipt, storage and assembly — after the gas plant is completed, the company said.

The math for new gas and solar plants is more encouraging than that of coal. In 2019, a new CCGT would have received sufficient net revenue to cover levelized total costs in half of PJM’s 20 zones, the Monitor reported. Cost recovery was 98% in 2019 in the APS zone, where Longview is located.

New solar projects would have sufficient net revenue to cover levelized total costs in AECO, JCPL and PSEG, where renewable energy credit revenues are high, but not enough to cover costs in Dominion or DPL, the Monitor said. ■



Proportion of units recovering avoidable costs: 2011-19 | Monitoring Analytics

PJM News



Artificial Island Cost Dispute is Over — Almost PJM's 1st Order 1000 Project Nears Completion

By Rich Heidom Jr.

The long-running dispute over who pays for PJM's first Order 1000 transmission project is finally nearing an end.

The \$266.5 million Artificial Island stability project likely also generated millions in legal fees over the past six years, first in a fight over competitive bidding before PJM and later in an epic cost allocation saga before FERC.

On Thursday, FERC ended its refereeing in the cost allocation battle, rejecting a challenge to an April 2016 cost allocation order as moot because it was later reversed (ER15-2563). The commission also terminated docket EL15-95-002, saying rehearing requests in it have already been addressed in other dockets. Still pending is a *petition* filed by PPL Utilities

in February asking the D.C. Circuit Court of Appeals to review three commission orders in the dispute.

Meanwhile, the project, which includes a new transmission line between New Jersey and Delaware, is scheduled to be completed by the end of May. The project is designed to address stability limits on generation at the Salem and Hope Creek nuclear plants in New Jersey and transmission constraints that sometimes prevent the generators from exporting power at full capacity.

Stability vs. Power Flow

The original cost allocation would have assigned virtually all the costs of the project to Delaware and Maryland ratepayers, prompting state regulators to file a complaint alleging that the use of the solution-based distribution

factor (DFAX) method was unjust and unreasonable when the benefit was system stability rather than power flow (EL15-95). In April 2016, the commission denied the complaint and accepted PJM's proposed cost allocation (ER15-2563).

In July 2018, however, the commission reversed itself, finding the use of the solution-based DFAX unjust and unreasonable for stability-related reliability violations like that of Artificial Island. (See *FERC Rethinking DFAX for Stability Tx Projects*.) It approved PJM's proposed "stability deviation" method — which identifies which loads would most benefit from projects that address stability issues — in February 2019. (See *FERC: Stability Deviation Method Best for Artificial Island*.)

On March 16, 2020, the commission accepted cost responsibility assignments for 20 baseline



Illustration of Artificial Island stability project by LS Power's Silver Run Electric | LS Power

PJM News

transmission projects, including reallocation of cost responsibility for Artificial Island based on the stability deviation method (ER20-736).

The commission's Thursday order said that although it had initially accepted cost allocations using DFAX, the cost assignments never went into effect, rendering the rehearing requests in docket ER15-2563-002 moot.

"We're excited about the end of the FERC process," Sharon Segner, vice president of LS Power, said Monday. "It's a big victory for Delaware consumers."

LS Power won a share of the Artificial Island project after challenging PJM's original award to Public Service Electric and Gas and promising to cap its cost at \$146 million. Last month, FERC approved rules on how PJM will evaluate voluntary cost commitment proposals in the

future. (See *FERC OKs PJM Tx Cost Containment*.)

LS Power Group's *Silver Run Electric* is building a new substation in Delaware and a 5.5-mile, 230-kV transmission line, including a 3-mile crossing under the Delaware River, between the substation and the Hope Creek nuclear plant.

Nearly Done

The project, PJM's first competitive solicitation under Order 1000, has a projected in-service date of June 1, according to PJM records.

"It's nice when you've spent so much time on the policy side of Order 1000 seeing the fruits of LS Power's work," said Segner, who is a regular presence at PJM stakeholder meetings on transmission. She said FERC's *Standards of Conduct* prevent her from sharing nonpublic, market-sensitive details about the status of



LS Power used helicopters for moving workers and materials during construction of the Artificial Island stability project. | LS Power



The Hope Creek and Salem nuclear units on Artificial Island in southern New Jersey | BHI Energy

the transmission construction.

LS Power is one of three companies building the project.

Delmarva Power is interconnecting the Silver Run substation with the existing 230-kV Red Lion-Cartanza and Red Lion-Cedar Creek lines for \$2 million.

PSE&G is expanding its Hope Creek substation with a new 500/230-kV autotransformer and a new 500-kV bay for a combined \$118.5 million.

Excluding the \$51.5 million 500-kV bay at Hope Creek — which was allocated 50% based on load-ratio-share among 22 transmission zones, and 50% on the stability deviation method — the costs were allocated based on stability deviation among 10 transmission zones. ■

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PJM News



FERC: RGGI, Voluntary RECs Exempt from MOPR

Monitor: Md. Costs Likely to Rise with FRR

Continued from page 1

The commission also ordered PJM to file Tariff revisions expanding eligibility for the categorical MOPR exemption to include new resources that had obtained interconnection service agreements, wholesale market participant agreements or interconnection construction service agreements — the final stages of interconnecting to the PJM system — prior to the December order.

“The categorical exemptions were designed so as to not unduly disrupt established investment decisions,” the commission said. “Resources that have not reached this stage of the interconnection process are not sufficiently advanced in the development process to warrant one of the categorical exemptions.”

Chairman Neil Chatterjee announced the decisions at the commission’s monthly open meeting, which was held via teleconference because of the COVID-19 pandemic. Chatterjee reiterated that the commission’s directive was needed to respond to subsidized resources that he said are suppressing prices in PJM’s capacity market. The new rules, he said, will result in a “level playing field” for unsubsidized generation.

‘Stunningly Awful’

Commissioner Richard Glick, who dissented on the two original orders, repeated his criticism Thursday, calling the rehearing orders “stunningly awful” and the majority’s logic “just plain garbage.”

“At his December press conference, Chairman Chatterjee made an astounding admission: The commission issued the MOPR order without even considering the impact of this order on consumers. Today the commission continues to blunder down that path without attempting to assess the billions of dollars it will impose on customers. And I believe that abdicates our regulatory duty.”

Glick rejected the majority’s contention that it needed to act to protect the competitiveness of the wholesale market. If that were the motivation, he said, the commission would not have exempted subsidies such as siting incentives, subsidies that previously went to conventional generation or federal subsidies.

He said the commission “twisted itself into a pretzel” on the issue of federal subsidies.



FERC Chairman Neil Chatterjee (left) and Commissioner Richard Glick chat before the start of the commission's open meeting in September 2019. | © RTO Insider

“The commission argues that it can’t subject federal subsidies to the MOPR because that would block Congress’ policy objectives,” he said. But when parties said in rehearing requests that the ruling was frustrating state policy in support of renewables, “the commission’s response is that the MOPR does no such thing. The commission cannot and should not have it both ways,” he said.

Glick said the real motivation for the order is to counter state efforts to address the externalities of greenhouse gas emissions from fossil fuel generators. “That appears to be bothering this commission,” he said.

In a press conference after the meeting, Chatterjee rejected Glick’s criticism. “These are well reasoned orders, and broad attacks like that mean very little,” he said.

Chatterjee also disputed Glick’s contention that the expanded MOPR will cost consumers billions — a prediction that some, including PJM’s Independent Market Monitor, have disputed.

The Monitor released an analysis last month that concluded that expanding the MOPR will not have an impact on clearing prices or auction revenues for the next Base Residual Auction, for delivery year 2022/23. (See [MOPR May Not be Death Knell for Renewables in PJM.](#))

Rehearing Rejected

The commission rejected arguments that it failed to cite evidence that state out-of-market

support is causing price suppression.

“These rehearing arguments rest on the faulty assumption that, in order for the commission to sufficiently support its Section 206 finding that PJM’s existing Tariff is unjust and unreasonable, the commission is required to analyze the results of previous capacity auctions and demonstrate that that state subsidies have had a significant price-suppressive effect,” FERC said. “Rather, to support its Section 206 finding, it was appropriate for the commission to rely on record evidence and basic economic theory to conclude that PJM’s existing Tariff does not account for and mitigate the price-suppressive impact of state subsidies. ... While the June 2018 order does not find that any particular capacity auction has produced unjust and unreasonable results, the commission need not wait to address price distortions from subsidized resources until it finds that the capacity auction has produced unjust and unreasonable results.”

It also dismissed arguments that an efficient market would price environmental externalities as “not relevant.”

“The purpose of a capacity market is to ensure resource adequacy at just and reasonable rates, not to mitigate the negative externalities associated with the production of electricity,” it said.

FERC also rebuffed claims that it had failed to follow precedent because it previously found that renewable resources do not pose a threat

PJM News



of price suppression. “Circumstances have changed. Evolution of the commission’s policy is justified in response to the proliferation of out-of-market support to resources that permit these resources to offer noncompetitively and suppress prices,” it said.

And it said its orders did not violate state sovereignty, saying out-of-market payments such as RECs and zero-emission credits for nuclear plants allow resources to make capacity market offers below costs. “Because these programs disrupt competitive price signals that PJM’s capacity auction is designed to produce, we are obligated to act to deter uneconomic participation,” it said.

Glick’s dissents on Thursday’s rehearing orders criticized the commission for “a degree of condescension that is unbecoming of an agency of the federal government.”

He said the majority was abusing the MOPR concept, transforming “a narrowly tailored anti-monopsony measure into a regime for blocking state efforts to shape the generation mix.”

Glick predicted the orders will result in the “fracture” of PJM, the largest RTO in the country.

“States throughout the region are already looking for ways to pull their utilities out of the capacity market rather than remain under rules designed to damage their interests. Today’s orders snuff out what little hope may have remained that the commission would again change course and adopt a more sensible market design.”

Next Steps

FERC on Thursday also dismissed as moot a complaint by CPV Power Holdings over PJM’s MOPR, saying the relief the company had sought was addressed by the June 2018 and December 2019 orders ([EL18-169](#)).

The commission also denied requests for rehearing of its April 2019 order approving PJM’s quadrennial revision of the variable resource requirement (VRR) — the demand curve for the capacity market — rejecting complaints that it results in over-procurement of capacity. The order affirms PJM’s selection of the CT H-class turbine as the reference resource ([ER19-105-004](#)). The Sierra Club and the Natural Resources Defense Council released a [study](#) in February alleging PJM’s over-procurement costs consumers billions annually.

By ruling on the rehearing orders, FERC started a 60-day clock for those who want to challenge its rulings before the D.C. Circuit

Court of Appeals. Dozens of stakeholders filed requests for rehearing or clarification of the December order, with some observers predicting the issue will end up before the Supreme Court. (See [PJM MOPR Rehearing Requests Pour into FERC](#).)

The New Jersey Board of Public Utilities issued a statement saying it is “deeply disappointed that FERC has once again sided with the fossil fuel industry rather than allowing states to implement policies that best benefit their residents. The decision fails to recognize the important steps we must take to address the impacts of climate change on New Jersey. We will fight this decision as vigorously as possible at every opportunity, and we will not let FERC’s actions stand in the way of implementing Gov. [Phil] Murphy’s clean energy vision. The governor is committed to continuing the battle against the devastating impacts of climate change and creating a safer, healthier environment and economy for all New Jerseyans.” The BPU last month opened an investigation to consider alternatives to the PJM capacity market. (See [N.J. Investigating Alternatives to PJM Capacity Market](#).)

Reaction

Jeff Dennis, managing director and general counsel for Advanced Energy Economy, said, “FERC’s decision to deny rehearing will only increase the growing tension and costly misalignment between state clean energy policies and federally regulated wholesale markets.”

But Todd Snitchler, CEO of the Electric Power Supply Association, praised the rulings. “FERC and Chairman Chatterjee today put consumers first by clarifying a ruling with significant impacts for 65 million electricity customers in PJM and nationwide. This is a step toward resolving concerns surrounding state goals and regional power markets, and we are pleased to see the commission act swiftly in support of fair competition in PJM’s capacity market.”

FERC’s exemption of RGGI and voluntary RECs from MOPR was consistent with the compliance filing PJM filed in March, which said capacity resources that generate RECs can use the MOPR’s competitive exemption if they certify that the credits will only be used and retired for voluntary obligations rather than state-mandated renewable portfolio standards. (See [PJM Makes MOPR Compliance Filing](#).) Comments on PJM’s compliance filing are due May 15.

Chatterjee declined to comment on how quickly the commission will act on the compliance filing, but he did address concerns that some

states might seek to pull their utilities out of the capacity market as a result of the ruling.

“Organized, competitive markets bring significant benefits to consumers, and I think state leaders will be really hard-pressed to ignore that,” he said. “From my view, I think that state leaders will wait to see how this plays out, wait and see how the auctions go and then reassess.”

Monitor: Maryland FRR Likely to Increase Capacity Costs

Also on Thursday, the Monitor released a [report](#) concluding that Maryland customers would likely pay higher capacity prices if the state’s utilities left PJM’s Reliability Pricing Model and acquired their capacity through a fixed resource requirement (FRR).

In five of six scenarios considered, Maryland ratepayers within the FRR would see capacity costs increase by 6 to almost 43%, while the state’s overall costs would be either unchanged or rise by as much as 23%. One scenario — the creation of an FRR for the Maryland portion of the Pepco locational deliverability area (LDA) — suggested costs within the LDA could drop by 5% and the rest of the state by 1%.

“Based on the analysis, the creation of a Maryland FRR, a BGE FRR or a Pepco/MD FRR, is likely to increase payments for capacity by customers in Maryland,” the Monitor said. “Creation of an FRR creates market power for the small number of local generation owners from whom generation must be purchased in order to meet the reliability requirements of the FRR entities. There is at least one single pivotal supplier in each of the Maryland, BGE and Pepco FRRs, which means that there is at least one generation owner, and in some cases more, that has monopoly power in each case.

“In the FRR approach, there is no PJM market monitoring of offer behavior by generation owners; there are no market rules governing offers; and there are no market rules requiring competitive behavior,” the Monitor continued. “As a result, even the higher estimates of the cost impact to the customers of Maryland from the creation of an FRR are likely to be conservatively low. If Maryland were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.”

The Monitor released a [report](#) in December that concluded that creation of an FRR in Commonwealth Edison’s LDA in Illinois was likely to increase capacity costs for ComEd customers while reducing capacity costs elsewhere in the RTO. ■

PJM News



PJM Ordered to Recalculate Wind Farm's Capacity Rights

By Rich Heidom Jr.

PJM must recalculate an Illinois wind farm's incremental capacity transfer rights (ICTRs) based on the information available to the RTO when it completed the interconnection customer's system impact study (SIS) in 2015, FERC ruled Thursday ([EL18-183](#)).

ICTRs — available to interconnection customers that are required to fund a transmission facility — are awarded based on how much the improvement increases the transmission import capability into a locational deliverability area (LDA). ICTR holders receive revenues if the LDA in question is constrained in subsequent capacity auctions. The rights are good for up to 30 years.

In 2018, the commission granted a complaint by Radford's Run Wind Farm, which said PJM unfairly denied ICTRs for funding an upgrade identified in its SIS to mitigate a thermal overload on the 345-kV Loretto-Wilton Center line. Radford's upgrade increased the rating of the line by 47 MVA.

The commission's 2018 ruling ordered a paper hearing to determine whether the upgrade increased the capacity emergency transfer limit (CETL) of the ComEd LDA, entitling it to ICTRs.

PJM contends that although Radford's SIS was completed in December 2015, the CETL calculation should be forward-looking, and thus based on the planning model developed in January 2016, which set the CETL values for the May 2016 Base Residual Auction. PJM said the 2016 analysis showed that the Radford upgrade did not increase the CETL for the ComEd LDA because a voltage collapse concern on the 765-kV Dumont-Wilton line was more constraining.

Radford owner E.ON Climate & Renewables N.A. — which opened the 306-MW wind farm in Macon County, Ill., in 2018 — said the analysis should have used the base case for the 2015 BRA, which it contends would have entitled it to 279 MW of ICTRs.

FERC sided with Radford, saying PJM's Tariff did not allow the RTO to delay Radford's SIS or its ICTR calculations.

"While we appreciate PJM's desire to use the most up-to-date data for all its analyses, we find PJM's suggested use of later data inconsistent with the certainty and predictability required by the Tariff provisions addressing



Radford's Run Wind Farm | E.ON

the timing of studies," FERC said. "For these reasons, we direct PJM to award any ICTRs that would have been assigned to Radford as of December 2015, as PJM would have done had PJM followed its Tariff."

It required PJM to make a compliance filing within 60 days. If PJM determines Radford is entitled to ICTRs, it must determine whether the company would have received payments relating to the BRAs held in 2016, 2017 and 2018.

"We see no reason not to require PJM to apply its Tariff correctly and to rebill parties for their correct quantity of ICTRs. Accordingly, we will exercise our discretion and require PJM to resettle payments for ICTRs resulting from the 2016 Base Residual Auction with a 2019/20 delivery year and to rebill affected entities for that period."

Rule Change

In response to FERC's 2018 ruling, stakeholders last year approved revisions to the timing and study parameters for determining ICTRs. (See "Revisions on Incremental Capacity Transfer Rights Endorsed," [PJM MRC/MC Briefs: Jan. 24, 2019](#).)

The change, accepted by FERC last April, allows new service customers to request an ICTR determination on customer-funded upgrades after executing a facility study agreement (FSA) — a later phase in the interconnection process than the SIS — and before

the issuance of an interconnection service agreement or construction service agreement. It also limits the requests to no more than three LDAs ([ER19-982](#)).

PJM said the change was needed because the procedures detailed in the Tariff would result in delays in processing interconnection requests. PJM said it takes from an additional day to more than one work week to conduct ICTR determinations for each customer-funded upgrade identified across all 27 LDAs in the RTO.

It noted that of the 2,073 customers receiving SISes over the prior decade, only 729 customers proceeded to execute an FSA. PJM also said that when projects drop out of the queue, it must repeat SISes for projects lower in the queue. Delaying ICTR determinations until after execution of an FSA also provides more certainty on costs, PJM said.

EDF Renewables and Renewable Energy Systems Americas filed a joint protest contending that interconnection customers need all possible information at the SIS stage in order to make an informed decision about whether to remain in the queue. They noted that ICTRs can be worth millions of dollars over a 30-year period.

The commission rejected the protest, concluding that the RTO's changes "appropriately balance the needs of new service customers seeking ICTRs... with promoting the efficient processing of PJM's interconnection queue." ■

PJM News



PJM PC/TEAC Briefs

Planning Committee

RTMEP Process Ready to Move Ahead

PJM told the Planning Committee on April 14 that it is standing behind its intention to seek stakeholder approval of a new regional targeted market efficiency project (RTMEP) process without first developing cost allocation rules.

PJM attorney Pauline Foley reiterated her statements from the committee's March 10 meeting, saying FERC has historically reviewed planning processes separately from cost allocation. The RTO has said cost allocation is the responsibility of transmission owners under the Consolidated Transmission Owners Agreement (CTOA) and should not be considered until FERC approves the planning change. (See [LS Power Challenges PJM on MEP, SATA.](#))

LS Power's Sharon Segner acknowledged that cost allocation is the TOs' responsibility, but she said FERC Order 1000 requires any regional planning process to be accompanied by a cost allocation methodology. Segner reviewed a [legal memo](#) filed by LS Power regarding cost allocation for the new project category.

Foley said she agreed with LS Power's contention on the importance to know the cost allocation methodology before PJM designates a project or implements a planning process. But she disagreed with the memo's contention that

a methodology must be simultaneously filed with the planning process. "I don't see anything in Order 1000 that says that," she said.

PJM officials noted that stakeholders have been working on the issue for at least 18 months and said that if it's pushed back any further, it could prevent implementation before 2022. PJM stated it is prepared to seek a vote on a new measure at the May PC meeting.

Alex Stern of Public Service Electric and Gas [provided a response](#) from the TOs regarding the LS Power memo. He said the plans that have been proposed follow existing transmission planning principles and comply with Order 1000.

"Once we have an effective [stakeholder-approved] package, the TOs will begin developing any needed cost allocation revisions that emerge," Stern said. "This is consistent with the transmission planning approach that has been followed in the past."

Segner said there remains a "long path ahead" on the RTMEP process for stakeholders. She said there has been no consensus on the proposals submitted thus far.

"The members deserve to know the cost allocation methodology for an entirely new type of regionally planned project category," Segner said. "If FERC can't accept these filings without understanding what the cost allocation

methodology is going to be, why should the members? Why is it that the members are considering approving changes without knowing what the cost allocation framework is going to be?"

Competitive Planner Nears Debut

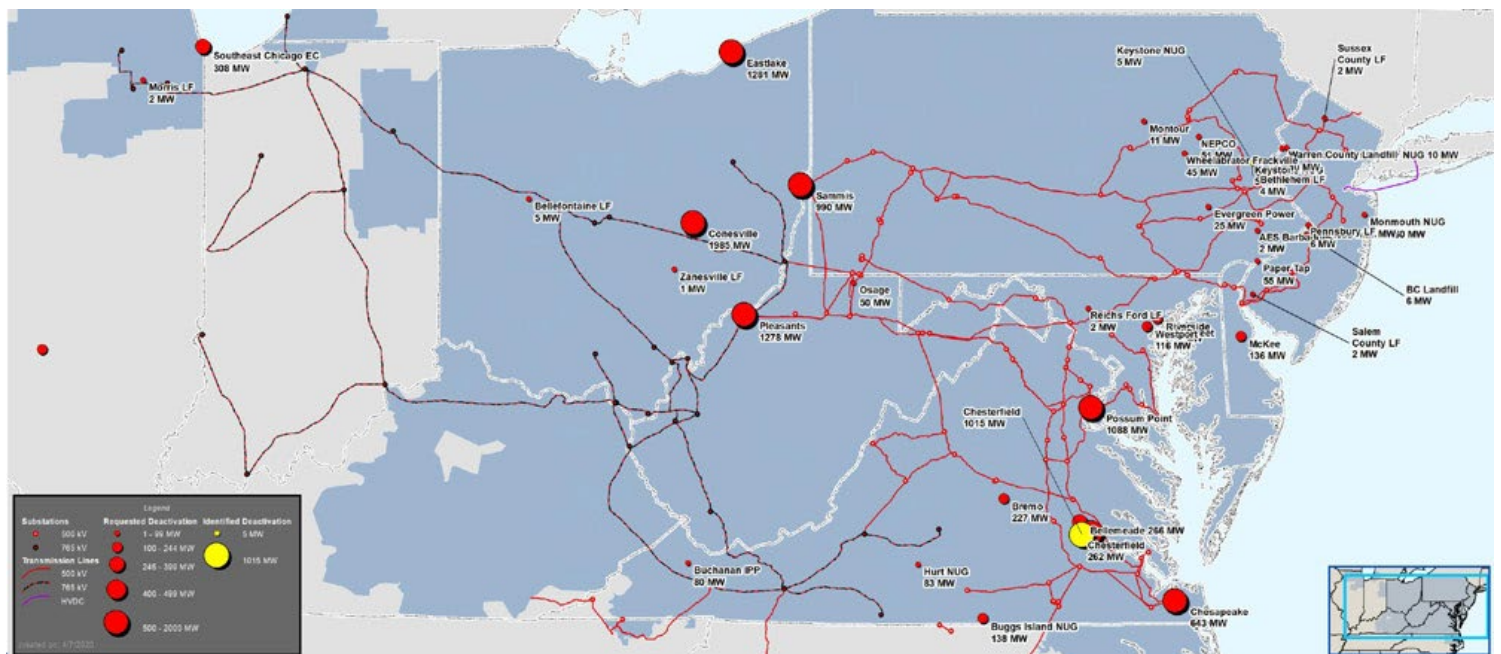
Ilyana Dropkin of PJM presented an update on the Competitive Planner, a new web-based application for TOs and developers to participate in the RTO's competitive planning process under Order 1000.

By publishing a set of criteria violations and soliciting solutions from competing developers in the new application, Dropkin said, PJM and FERC are hoping to encourage innovative and cost-effective solutions for transmission needs.

Dropkin said that having a web-based application increases the speed and accuracy of the process and provides near-real-time tracking of submissions.

Anyone looking to participate in PJM's competitive planning process can get access to Competitive Planner by prequalifying through the critical energy/electric infrastructure information (CEII) process, Dropkin said.

Training for the application is expected to be available on May 6, Dropkin said, and the full implementation of Competitive Planner is



Generation deactivations for 2018-2020 | PJM

PJM News



expected by June 24.

Transmission Expansion Advisory Committee

Deactivation Notifications

Phil Yum of PJM provided the Transmission Expansion Advisory Committee an update on two recent generation deactivation notifications.

The first highlighted was PPL's Keystone NUG, a 4.9-MW coal-fired unit scheduled to retire on May 31. Yum said PJM determined during analysis that no violation was identified with the unit's closure.

Second, Chesterfield Units 5 and 6, producing 1,015 MW in the Dominion zone, are scheduled to retire on May 31, 2023. Yum said a generation deliverability problem was discovered at the Chickahominy 500/230-kV transformer that was overloaded for loss of the Chickahominy-Surry 500-kV line.

Yum said PJM is recommending installing a second Chickahominy 500/230-kV transform-

er at an estimated cost of \$22 million.

PJM: Error had no Impact on Project Selection

PJM's Brian Chmielewski told the TEAC that FirstEnergy's admission that it included an incorrect winter-normal rating in its proposed rebuild of the 115-kV Hunterstown-Lincoln line did not affect the RTO's selection of the project (HL_622).

PJM selected the \$7 million proposal by FirstEnergy's Mid-Atlantic Interstate Transmission (MAIT) subsidiary as the solution for the Hunterstown-Lincoln congestion driver following the 2018/19 long-term window.

After MAIT told PJM of the error on March 6, the RTO's market efficiency unit reran the proposal with the updated rating, Chmielewski said. "There was no change to the congestion or dispatch when that rating was updated," he said, adding that PJM stands by its decision.

In February, Ameren asked PJM to reconsider its selection of the project over 22 other proposals, including the company's proposal for

installing a SmartWires SmartValve. (See *PJM Rejects Ameren Challenge on Tx Project.*)

RTEP Window Delayed

PJM's Aaron Berner *said* delays in the development of Regional Transmission Expansion Plan cases have pushed its schedule back by three weeks. Posting of preliminary violations, originally targeted for April 15, is now expected on May 8. The opening of the 60-day proposal window, originally expected June 1, is now set for June 24.

Supplemental Project

Paul Mills of Commonwealth Edison presented needs and a solution for *several supplemental projects*, including the Lisle 345/138-kV Transformer No. 83 that acoustic testing showed higher-than-expected vibration levels and increased frequencies associated with looseness in the core/coil assembly. The solution calls for replacing the transformer and adding a high-side circuit breaker at a cost of \$8.5 million. ■

— Michael Yoder



Dominion Energy announced the two coal-fired units at its Chesterfield Power Station will retire on May 31, 2023. | Dominion Energy

PJM News

PJM Eyeing New Black Start Changes

By Michael Yoder

While PJM's controversial initiative to tighten fuel requirements for black start resources is on pause, the RTO said last week it wants to clarify and update its documentation on the substitution and termination of those resources.

PJM's David Kimmel presented a first read of a proposed [problem statement](#) and [issue charge](#) at the Operating Committee meeting Thursday, saying PJM officials have identified four areas in the Tariff and manuals in need of updates.

Last month, PJM suspended its initiative looking at black start fuel requirements, which faced opposition from state regulators and consumer advocates. (See [PJM Backs off Black Start Fuel Rule](#).)

Kimmel said while the fuel requirements initiative remains on "hiatus," the RTO wanted to clean up black start resource language in the Tariff not related to fuel.

"We have received a lot of questions on substitution, and we wanted to make those rules more clear," Kimmel said.

PJM is first rewriting language for testing requirements for black start resources not compensated through Schedule 6A of the Tariff. Kimmel said PJM has identified the need to provide clarity within testing requirements to ensure consistency, including test submittal timelines, for black start units compensated by either PJM or transmission owners.

Kimmel said the black start units in PJM are



Tasley, a single-unit 33 MW industrial gas turbine that began commercial operation in 1972 in Tasley, Va., is a black start capable unit. Calpine acquired Tasley in 2010 as part of its purchase of the Conectiv Energy assets. | [Calpine](#)

typically compensated through Schedule 6A, while some units entered service through a contract with a TO that was integrated into the system. In order to receive compensation, the unit must submit a successful black start test to PJM every 13 months.

The second clarification PJM is seeking is on black start unit substitution rules. Currently the Tariff allows a black start unit owner to substitute another unit as long as it's on the same voltage level and has a valid annual black start test.

Kimmel said PJM has received increased questions on adding, maintaining and managing units as black start substitutes. He said some of the questions that have been raised include the notification time required to allow a substitution and how to manage updates to system restoration plans documenting black start resources.

Black start termination rules are also being addressed, Kimmel said, to address potential delays in planning and replacement.

PJM and black start unit owners are currently required to provide a one-year advance notice of intent to terminate service. Kimmel said that could allow a unit to remain in the system without a successful test on file for an extended period of time before being terminated, delaying PJM from procuring a replacement.

The RTO also is looking to update the black start capital recovery factor (CRF) table in the Tariff to reflect current tax law and interest rates. It also is exploring a new process for automatically updating and documenting the table to remain current.

Kimmel said black start units electing to recover new or additional capital costs must commit to provide black start service for a term based on the age of the unit, and the CRF table lists the term periods of commitment and applicable capital cost recovery factors. He said recent tax law and interest rate changes don't reflect the assumptions used in the current CRF and need to be updated.

Work on the proposed changes is expected to take two to three months, Kimmel said, and it could be another six months before the changes would take effect in the Tariff. Changes are also anticipated to Manuals 10, 12 and 14D.

Process Questions

Independent Market Monitor Joe Bowring said he agreed with PJM's proposal that the



Joe Bowring, PJM's Independent Market Monitor | © RTO Insider

CFR table needs to be modified for tax law changes. He recommended that a reference interest rate be used as part of the problem statement and issue charge for the new changes and that the Moody's Utility Index for bonds already in use in the Tariff for black start-related matters be the benchmark.

Bowring also said he would also like to see the black start minimum tank suction level (MTSL) issue addressed in the new changes. He said the MTSL has been an issue for several years that has not been clearly addressed. PJM had agreed with the Monitor's position and had included such an agreement in the black start fuel requirement initiative that is now on hiatus, he noted. (See "Black Start Fuel Assurance," [PJM Operating Committee Briefs: May 1, 2018](#).)

PJM's Tom Hauske said the MTSL is still part of an active stakeholder process with the fuel resource initiative and should remain there.

"We're not sure that you can pull something from one stakeholder process and then bring it over into a whole other stakeholder process," Hauske said.

Bowring said he didn't see why the MTSL issue couldn't be addressed in the new process, as the fuel cost committee is currently on hiatus. Bowring also pointed out that the CRF table was part of the fuel assurance matrix being discussed in the black start fuel requirement.

Hauske said the previous fuel assurance matrix discussion dealt only for new units that were going to provide fuel assurance and did not apply to current units that were switching to black start, which is what the new proposed changes are meant to answer. ■

PJM News



PJM Operating Committee Briefs

Winter Operations Review

The winter of 2019/20 saw PJM with the lowest peak loads of the last seven years, as temperatures 4 to 6 degrees Fahrenheit above the long-term average kept energy consumption down.

Executive Director of System Operations Paul McGlynn *told* the Operating Committee on Thursday that the highest peak load was on Dec. 19 at slightly over 120,000 MWh, 10,000 MWh below the next lowest peak during the winter of 2015/16.

LMPs were very low all winter, McGlynn said, coming in at an average of \$21.31/MWh compared to the next lowest recent number of \$26.16/MWh in 2015/16. LMPs exceeded \$100/MWh for only three hours over the winter.

For the fourth straight year, natural gas was the primary fuel for generation, with a 38% share, compared to 35% for nuclear, 19% for coal and 7% for renewables. Natural gas overtook nuclear in 2016/17 as the most utilized winter fuel. Gas also passed coal that year as the most utilized fuel during winter daily peak hours.

The relatively mild winter, with few major snowstorms, led to only 12 emergency procedure events during the season, McGlynn said, the lowest total in the last six years. By comparison, PJM saw 43 emergency procedures in 2014/15.

“From an operational perspective, it was a fairly unremarkable winter,” McGlynn said.

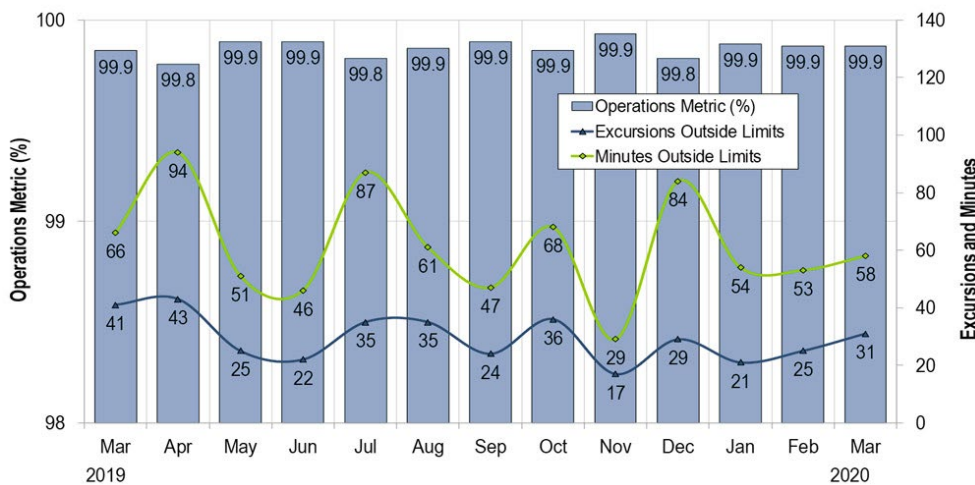
Review of Operating Metrics

PJM’s Stephanie Monzon reviewed March’s *operating metrics*, highlighting that the balancing authority area control error limit (BAAL) performance has exceeded the 99% goal each month in 2020 so far, at 99.9%.

The BAAL standard was created to maintain stable interconnection frequency under normal and abnormal conditions to prevent instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages.

PJM compares the BAAL excursions in minutes to the total minutes within a month.

Monzon also pointed out the perfect dispatch performance score through March 2020 was 94.81%. Perfect dispatch refers to the hypothetical least production cost commitment and



Monthly BAAL performance score. | PJM

dispatch, achievable only if all system conditions, including load forecast, unit availability and transmission outages, were known and controllable in advance.

The perfect dispatch performance goal was designed to measure how well PJM commits combustion turbines in real-time operations compared to the calculated optimal CT commitment profile. Monzon said the perfect dispatch score has resulted in more than \$21 million in savings in 2020.

Monzon said March was a “rather quiet operational month,” with three post-contingency local load relief warnings, four high system voltages and one heavy load voltage schedule action. One spinning event was recorded on March 8, Monzon said, which took place in the Mid-Atlantic Dominion region, lasting a total of five minutes, with a Tier 1 estimate of 1,541.4 MW and an actual response of 660.1 MW.

System Operations Subcommittee Report

PJM’s Rebecca Carroll gave a *summary* of the most recent System Operations Subcommittee meeting held April 13. Carroll highlighted four high system voltage actions in March, which are typically seen during periods of low loads. PJM will likely continue to see similar events in the upcoming months because of the impacts from the COVID-19 pandemic and the stay-at-home orders, she said.

Carroll said all weeks of the 2020 Operator Seminar have been canceled because of the pandemic. She said if operators need training hours to renew their certification, they should

reach out to PJM at TrainingSupport@pjm.com.

While most offices remain closed, Carroll said the *PSI testing centers*, which administer tests required for PJM training, will reopen about May 1. Masks and gloves will be allowed for anyone going into the training center, she said.

Load Forecast Model Performance

PJM’s Elizabeth Anastasio provided an educational *presentation* on the performance of the RTO’s neural network machine learning algorithms, which identify the relationship between historical loads and temperatures to create load forecasts. It also considers cloud cover, humidity and the “effective” temperature, a measure similar to wind chill that takes into account wind speed.

What makes a good forecast model, Anastasio said, is a relatively low average error and a bias near 0%. She said bias is calculated by taking the average of hourly errors of over- and under-forecasting to determine the proportion between the two.

Although no model can predict all conditions, accurate models also have relatively few outliers of significant forecasting errors, Anastasio said. She said the best models also don’t see clear trends with outliers occurring at the same time of year or day.

Anastasio said PJM forecasters are constantly trying to assess how to improve load forecasting by looking back at past data as well as current conditions, analyzing outliers and investigating other forecasting methodologies and machine learning. ■

— Michael Yoder

PJM News



PJM MIC Briefs

Work Continues on Stability-limited Generators

PJM's Market Implementation Committee on Wednesday resumed its discussion on potential changes to how the RTO curtails generating output when needed to maintain stability during maintenance outages. Generating units must sometimes be reduced below their normal economic max limit if a planned or unplanned transmission outage presents stability problems that could result in damage to the units.

Current rules require the RTO to implement a thermal surrogate to reflect the stability constraint in the day-ahead and real-time markets and to bind the constraint, affecting the unit's dispatch.

The MIC agreed in August to consider alternative approaches in response to a problem statement and issue charge by Panda Power Funds' Bob O'Connell, who said 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. Under the RTO's rules, only the affected generator would know of the constraint, O'Connell said, gaining a competitive advantage over other units and possibly incorporating greater mark-ups into their offers.

PJM's Keyur Patel gave a revised [presentation](#)

Wednesday showing examples of how the RTO's proposed approach would work. At the MIC's March meeting, Paul Sotkiewicz, PJM's former chief economist, said the examples in the RTO's presentation contained errors in its LMP calculations. (See "PJM Developing Alternative on Stability-limited Generators," *PJM MIC Briefs*: March 11, 2020.)

PJM's proposal is to model stability limits on generating units as a "capacity constraint" that doesn't directly affect the LMP.

Sotkiewicz, now with E-Cubed Policy Associates, thanked PJM for correcting the examples but pressed the RTO on the need for the change.

PJM's Joe Ciabattone said the problem is when day-ahead commitments differ from those in real time.

"You could have a feasible solution in the day-ahead that's infeasible in real time," requiring operators to decommit one of the two units in PJM's example and causing make-whole payments.

"We would prefer to have a solution that is feasible in both the day-ahead and real-time," he said.

The discussion of alternatives to PJM's proposal was cut short because the MIC meeting was running behind schedule.

ARR/FTR Market Task Force

PJM's Dave Anders *said* the ARR FTR Market Task Force has completed three of its five key work activities (KWAs) in the *issue charge* approved by the MIC in October: reviewing the evolution of PJM's auction revenue rights and financial transmission rights market design; reviewing congestion rights market designs of other regions; and discussing how PJM's current design accomplishes its objectives.

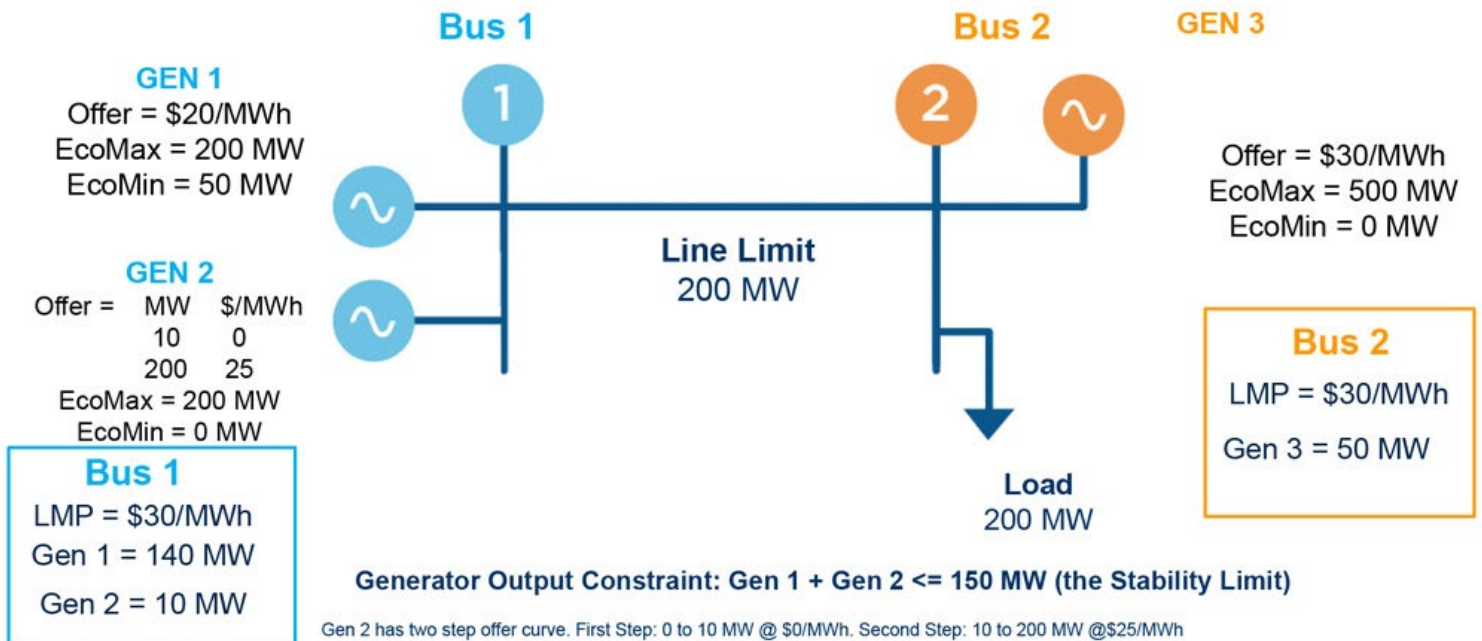
The task force is currently discussing the "value proposition" of the market, the fourth KWA, and will soon begin the final one, proposal development, which it expects to run through August.

The initiative grew out of a recommendation in PJM's independent consultant report on the GreenHat Energy FTR default that the RTO "conduct a general review of the FTR market ... to evaluate the risks and rewards of potential structural reforms."

The task force's next *meeting* is April 29.

nGEM Project Update

PJM has decided to expedite the implementation of network applications for day-ahead and real-time markets under its Next Generation Markets (nGEM) project, a multiyear partnership among PJM, MISO, ISO-NE and General Electric that began in April 2017.



PJM's proposed new approach for clearing stability-restricted generating units | PJM

PJM News



PJM's Todd Keech *said* the day-ahead market clearing engine released by GE in March met all performance improvement criteria specified in the development contract.

GE and PJM last month completed factory acceptance testing for capacity and FTR data transfer improvements and network applications; a final GE release for those functions is expected in the second quarter.

Keech said PJM is seeking to implement network applications for day-ahead and real-time markets in the fourth quarter to address findings from its "Markets Process Review."

The Phase 2 nGEM agreement is under negotiation, he said.

The partnership with GE allowed the grid operators to share in development and maintenance costs and reduce time-to-market. PJM said the project will improve system security and quality.

Performance Assessment Interval Report

PJM is considering changes to its manuals and Tariff to address "a lack of clarity and detail" and improve the transparency of its performance assessment interval (PAI) settlements process, PJM's Danielle Croop *told* the MIC.

Croop said the RTO will bring a problem statement and issue charge to an upcoming MIC meeting to address issues including ancillary service accounting and the determination of scheduled megawatts. It will also include provisions to make the language for energy-only and demand response resources parallel with that of generation resources, where applicable.

The initiative will seek to identify where more transparency or clarification is needed. "This

effort is not intended to redefine any previously defined practices surrounding the calculation of performance assessment interval nonperformance assessments," PJM said.

In March, PJM released a *report* on PAI settlements as an addendum to its *review* of the Oct. 1-2, 2019, performance assessment event, when an abnormal October heat wave led to emergency procedures and the first call on DR resources in more than five years.

The incident resulted in \$8.2 million in nonperformance charges. Bonus payments averaged \$32.89/MW-interval with the average bonus 9,706 MW/interval.

Independent Market Monitor Joe Bowring noted that the 2019 State of the Market report also includes an analysis of the October event. "We're also working on a confidential report that we will share with PJM," he said.

'Quick Fix' on PMA Credit Requirements

PJM's Bridgid Cummings presented the MIC with a *problem statement* and *issue charge* for a proposed "quick fix" Tariff revision to address a regulatory change in Ohio concerning the billing of network integration transmission service (NITS).

The RTO requires load-serving entities to sign NITS agreements and post collateral based on their peak market activity (PMA).

In 2015, the Public Utilities Commission of Ohio moved NITS and other related charges to a non-bypassable rider that is the responsibility of the electric distribution company. The change means competitive retail electric suppliers serving load in Ohio are no longer allowed to collect NITS or any other transmission-related charges from end-use customers.

As a result, PJM's credit requirements "do not reflect or consider the appropriate exposure for the responsible party" in Ohio, the problem statement says. "It is possible that other states may have similar laws in the future. This situation puts LSEs in those jurisdictions at a disadvantage with respect to having the responsibility for the applicable credit requirements in PJM although they have no responsibility for the underlying transmission service charges in the states in which they operate."

As a result, PJM is proposing to *amend* Tariff Attachment Q to allow the RTO to adjust PMA requirements "where state law requires the transfer of charges or credits from a participant to another party."

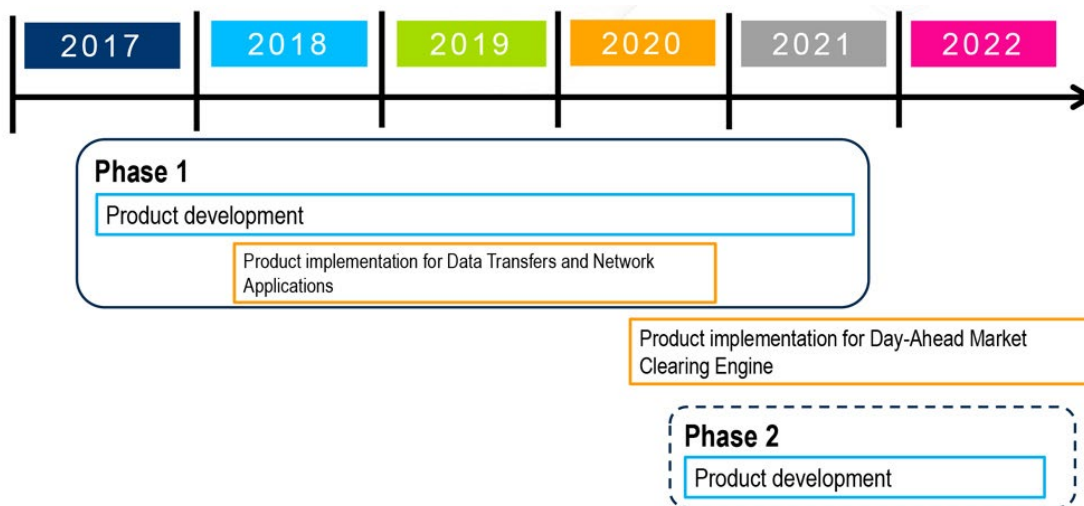
The committee will be asked to approve the issue charge and endorse the Tariff revisions at the May MIC meeting under the quick-fix process detailed in section 8.6.1 of Manual 34.

Regulation Market Settlement Agreement

PJM's Eric Hsia gave a *briefing* on PJM's *compliance filing* in response to FERC's March 26 order approving settlements of two complaints over PJM's regulation market design (ER19-1651-001).

The settlements resolved complaints filed in 2017 by the Energy Storage Association (EL17-64), and Invenergy and Renewable Energy Systems Americas (EL17-65), which alleged PJM's January 2017 regulation market redesign violated commission precedent and discriminates against faster, dynamic "RegD" resources such as battery storage. (See *FERC OKs PJM Regulation Deal over Monitor's Opposition.*) ■

— Rich Heidorn Jr.



Schedule for PJM's Next Generation Market (nGEM) project | PJM

SPP News



Golden Spread Ordered to Further Comply with Order 845

By Tom Kleckner

FERC last week partially approved Golden Spread Electric Cooperative's Order 845 compliance filing but directed the Texas utility to make another filing proving compliance within 120 days (*ER19-1900*).

The commission in November partially accepted Golden Spread's first compliance filing but found the cooperative's proposed tariff revisions lacked the requisite transparency required by Orders 845 and 845-A. It directed Golden Spread to make another compliance filing, which it did in January. (See *FERC Finds Partial Compliance on Order 845*.)

FERC issued the two orders in 2018 to increase the generator interconnection process' transparency and speed. The changes are grouped into three categories: improved certainty for interconnection customers; promoting more informed interconnection decisions; and process improvements. (See *FERC Order Seeks to Reduce Time, Uncertainty on Interconnections*.)

The commission found Golden Spread's tariff revisions related to provision of interconnection service and surplus interconnection service complied with the orders.



Lyntegar Electric Cooperative is one of Golden Spread's 16 members in oil-rich West Texas. | Lyntegar

But it said Golden Spread's proposed revisions to determine contingent facilities that provide sufficient transparency "appears to conflate" those facilities with network upgrades and interconnection facilities assigned to the interconnection customer and does not distinguish between the two.

"Golden Spread does not indicate how it will determine which of these facilities are

contingent facilities applicable to a particular interconnection request," FERC said. It directed the cooperative to describe in its *pro forma* large generator interconnection procedures (LGIP) the specific technical screens and/or analyses that it will employ to determine which facilities are contingent facilities and to describe the specific triggering thresholds or criteria applied to identify a facility as a contingent facility.

FERC defines contingent facilities as "unbuilt interconnection facilities or network upgrades upon which the interconnection request's costs, timing and study findings are dependent and, if delayed or not built, could cause a need for restudies of the interconnection request or a reassessment of the interconnection facilities and/or network upgrades and/or costs and timing."

The commission also found proposed revisions to the LGIP allowing interconnection customers to submit "proposed modifications" if they seek to incorporate technological advancements into their large generating facility did not comply with its November order.

FERC directed Golden Spread to revise its technological change procedure to state that an interconnection customer should submit a "technological advancement request" if it seeks to incorporate technological advancements into its proposed large generating facility. It also ordered the cooperative to make clear it will reach its final determination on whether a proposed technological change is a material modification within 30 days of receiving the request. ■



A gas turbine at Golden Spread's Elk Station plant | GE

SPP News



SPP Strategic Planning Committee Briefs

More Education Needed on Hedging Congestion

SPP Board of Directors Chair Larry Altenbaumer last week asked the Strategic Planning Committee for an education session on congestion hedging following stakeholder disagreement over the best way to proceed with a recommended white paper.

“The SPC’s role needs to come into sharper focus,” Altenbaumer, who also chairs the committee, said during its conference call Wednesday. “The best way to be successful with these recommendations is if they come up through the stakeholder process.”

The Holistic Integrated Tariff Team (HITT) last year recommended that SPP develop a market mechanism to hedge load against congestion charges. The team suggested modifying the existing market design to use only excess auction revenues to fund counterflow optimization positions.

The HITT directed the Market Working Group (MWG) to develop a white paper documenting a recommended path forward. The group came up with three counterflow optimization options:

- Assigning counterflow cost to the market participant after the annual auction revenue rights (ARR) auction’s first round.
- Assigning the counterflow cost to ARR surplus after the annual transmission congestion rights (TCR) auction.
- Creating a new round in the long-term congestion rights (LTCR) allocation, with the counterflow cost directly assigned to the market participant. If the LTCRs become infeasible, the cost is assigned to the ARR surplus.

The MWG rejected all three options during its February meeting, after having earlier voted to keep the current design for congestion hedging. The group has said the second option satisfies the HITT initiative, but the Markets and Operations Policy Committee rejected the option last week, directing the group to further develop the first option.

“You’re not going to get consensus on this, because a majority of the companies are happy with their hedging portfolios,” warned Bill Grant, with Southwestern Public Service. “When we designed the market, we decided against counterflows. The majority of the group is not recognizing there’s a problem. They’re looking at the monetary value their

customers are receiving from current hedging activities.

“The do-nothing option seems to be the one that’s winning the day.”

Keith Collins, executive director of SPP’s Market Monitoring Unit, said his team doesn’t have a preferred proposal but is considering developing its own mechanism “that could address the concerns of HITT and others.”

“Our view, as a neutral entity, is that the options have pros and cons. There are no clear-cut winners,” he said. “These are very complex issues. The TCR process is complex, but some of these solutions have additional layers of complexity. We’re happy to be engaged to find a solution.”

Committee Endorses 2 HITT Recommendations

The SPC endorsed two additional HITT recommendations that passed the MOPC the day before: the establishment of uniform Schedule 9 local planning criteria and the elimination of Z2 revenue crediting.

The committee approved the local planning criteria 9-1, with three abstentions. The elimination of Z2 crediting passed 12-0, with one abstention.

SPP members repeated some of the same concerns they had expressed during the MOPC meeting. The measure cleared the MOPC’s two-thirds approval threshold at 73.44%, evidence of transmission customers’ pushback over their perception that the process lacks transparency and does not treat all loads equally. The revision request relies on a “facilitating transmission owner,” determined yearly by the network customer with the largest load, scheduling an open meeting with other TOs, transmission customers and firm-service customers to establish the zonal planning criteria or any changes to it.

Golden Spread Electric Cooperative’s Mike Wise, SPC vice chair, said he felt the criteria’s language fell short as he shared with the committee the concerns of transmission-dependent utilities.

“The wholesale customers within the zones really wanted a collaborative process to be at the table,” he said. “Secondly, they understood there would be no cram-downs by the TOs. They hate it. They’ve lived with it for 60 years. We have to ensure all loads within a zone are treated equally and affiliates would not be favored through local criteria.”

American Electric Power’s Richard Ross said the idea that all loads will be treated equally would be the easiest “to scratch off the list as being nonexistent.”

“There will be one, singular policy that applies across the zone,” he said. “You’ll have the RTO applying that policy equally. It does require a collaborative process. At the end of day, someone has to make a decision if there’s not 100% agreement. We just need some experience with it. If people are not happy with it, we can revisit it.”

SPP Engineering Vice President Antoine Lucas said staff have been working to determine what “consensus-building” means in the context of local planning criteria.

“We came to the conclusion from staff’s role of facilitating the overall process that, within the zones, it’s probably more appropriate that they work together to define their view of consensus, or what levels of agreement are appropriate for moving forward,” Lucas said. “Does everyone have to agree with it? Maybe some voting structure needs to be put in place.”

SPC Adds New Members, Contracts with Facilitator

Barbara Sugg’s promotion to SPP’s CEO position and director Bruce Scherr’s recent passing has resulted in several changes in the SPC’s membership.

Bruce Rew, SPP senior vice president of operations, has replaced Sugg as the SPC’s staff secretary. Sugg, meanwhile, joins the committee as a member, while Director Susan Certoma replaces Scherr.

The committee has also entered into an agreement with an outside consultant to help facilitate and guide its future discussions. Strategic Offsites Group, a boutique Boston-based firm, was selected last month.

“We’re at a point now, with the way things are changing in the industry; we need to give it a fresh shot of thinking,” Altenbaumer said.

“We do not prescribe answers. I feel you have plenty of expertise in the organization,” Cary Greene, a partner with the firm, told the SPC. “Our job is not to tell you to go left or right, but to have a process in place where you decide what the strategies are.”

Greene said he expects to have a final strategic plan put together for the board in April 2021. ■

— Tom Kleckner

SPP News

SPP MOPC Briefs

MOPC Approves 2nd Run at Z2 Credits Elimination

SPP's Market and Operations Policy Committee last week endorsed a revision request that would again eliminate Z2 revenue credits for sponsored transmission upgrades, overlooking some members' concerns about a second regulatory defeat at FERC.

The commission in January rejected without prejudice SPP's proposal to use incremental

long-term congestion rights (ILTCRs) instead of Z2 credits, finding the modifications to the existing ILTCR compensation term to be unjust and unreasonable. However, the commission allowed the RTO to submit a revised proposal for the commission's consideration without a cap limiting the terms and potential value of the credits' replacement (ER20-453). (See *FERC Order Keeps Z2, Aids EDF's Sponsored Project.*)

SPP has proposed two changes in its latest revision request (RR 401), removing "maximum"

from the placeholder for the ILTCR's term and removing the cap on the amount recoverable through the candidate ILTCRs. The latter change would allow for a term of at least 10 years, but not more than 20 years, making the candidate ILTCRs viable and tradeable.

"We are confident this revision request addresses the concerns that were raised and will be approved by FERC," SPP attorney Tessie Kentner told the MOPC during its April 14 webinar. "Just because our ILTCR process is different than other ISOs and RTOs doesn't mean it's different from FERC's requirements."

SPP is required to file again with FERC by the end of April. It hopes to have ILTCRs replace Z2 credits by July 1.

Under Attachment Z2 of SPP's Tariff, sponsors that fund network upgrades can be reimbursed through transmission service requests, generator interconnections or upgrades that could not have been honored "but for" the upgrade.

EDP Renewables' David Mindham argued that because the latest Z2 filing fails to address substantive arguments raised in previous protests, it faces the "real risk" of being rejected by FERC. EDF Renewable Energy has said eliminating the Z2 credits would allow certain transmission customers to become "free riders," as they would no longer have to reimburse the upgrade sponsors for directly assigned upgrade costs.

"What's left after Z2 is removed is discriminatory, unjust and unreasonable," Mindham said. "It's clear from FERC precedent that all funders of transmission should be treated equally. This filing is a step back."

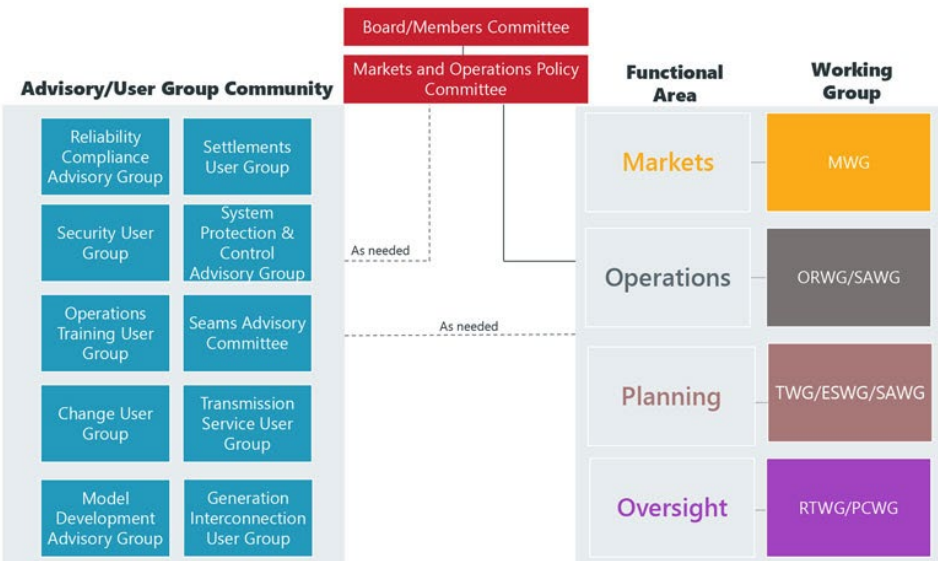
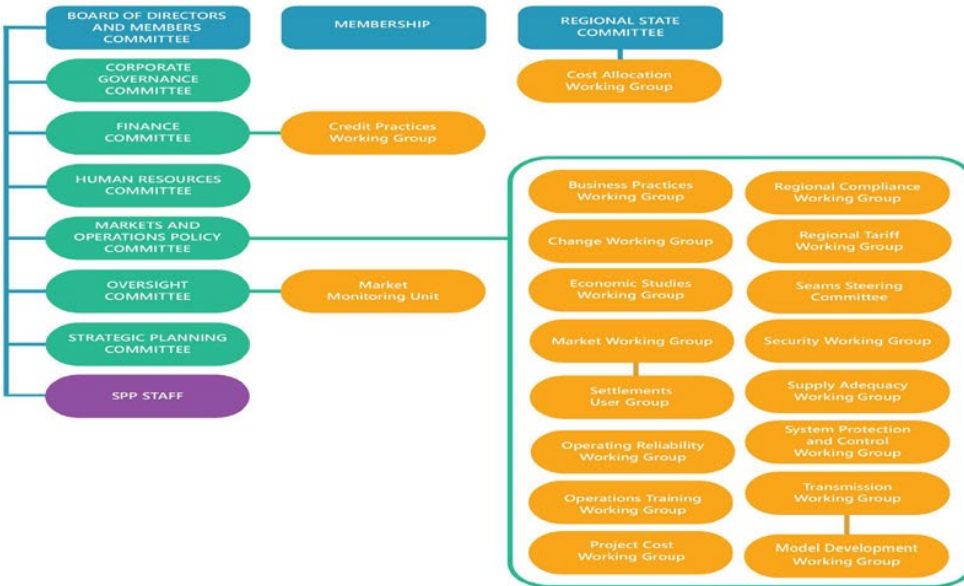
EDF legal counsel Dan Simon charged that SPP's ILTCRs are lacking, when compared to other RTOs and ISOs.

"The current rules for ILTCRs are just not as strong as they ought to be," he said. "We continue to hear people refer to the ILTCR product as 'worthless.' That demonstrates pretty clearly that the ILTCRs ... are not as good as other [RTOs]."

"There needs to be some sort of rate recovery mechanism for the entity that pays for that upgrade. ILTCRs don't serve that function in their current form," Simon said.

EDP cast the only vote against RR 401. Seven other members, primarily renewable developers and independent generators, abstained.

CURRENT ORGANIZATION



MOPC's current organizational structure (top), and the new structure for 2021 | SPP

SPP News



Zonal Planning Criteria Meets Opposition

MOPC members also sought to address another nettlesome issue — the tension between transmission owners and customers in the same transmission zones — with their approval of [RR 391](#).

As written, the change establishes uniform local planning criteria within each pricing zone under the Tariff's Schedule 9, placing the responsibility on the host TO to facilitate a "consensus-driven" criteria for reliability upgrades. Schedule 9 pricing zones calculate network service request charges as a ratio share of the monthly annual transmission revenue requirement.

Transmission customers pushed back against [RR 391](#) over concerns the process lacks transparency and does not treat all loads equally. The request hinges on the facilitating transmission owner (FTO), determined yearly by the network customer with the largest load, scheduling an open meeting with other TOs, transmission customers and firm-service customers to establish the zonal planning criteria or any changes to it.

"If you look at the definition of the FTO, one of the things it requires is that the largest load in the zone determine who the FTO is," Kansas Power Pool's Larry Holloway said. "I've never seen a more open violation of open access."

"I know consensus can't be forced, but this revision request does not even call for consensus," said consultant Jack Madden, representing the East Texas and Northeast Texas electric cooperatives. "It calls for a meeting, maybe only one, in which others are invited. After that, the FTO does or doesn't establish local planning criteria."

Madden said the Holistic Integrated Tariff Team, which included the Schedule 9 planning criteria among its recommendations last year, "clearly" considered a process that would lead to consensus. (See [SPP Board Approves HITT's Recommendations](#).)

"That language has been left on the cutting-room floor," he said.

Melie Vincent, director of operations for the Oklahoma Municipal Power Authority, referred to business clichés "hope is not a strategy" and "the past does not predict the future" in stating her case.

"Sure, we could have some blind faith. ... I don't want to hamstring efforts in the future, but I don't feel it protects the smaller players in the market," she said.

Oklahoma Gas & Electric's Greg McAuley, warning against the "esoteric rabbit trails" so common during MOPC discussions, said, "I haven't seen an example within SPP of anything like this being used in a heavy-handed way to force something down someone's throat when reliability is the ultimate goal."

"There's a difference between trying to reach consensus and actually reaching consensus," said Southwestern Public Service's Bill Grant. "It's important everyone gets to have input, and it's important you try to develop criteria that applies to everyone in the zone. It's in nobody's best interest to come up with criteria that doesn't work for everyone in the zone."

Not surprisingly, it took an electronic vote to determine the motion had passed with an overall approval of 73.44%. Fifteen of the 17 TOs approved the motion, but the margin was much slimmer among transmission customers. They approved the motion 17-15, with 10 abstentions.

Members Vote for 50-50 Split in ITP 2021 Futures

The MOPC revisited the consolidation of futures in the Integrated Transmission Planning process' 2021 assessment, rejecting a working group's recommendation for a more conservative blending of the scenarios.

Members voted down a motion to use a 60-40 split between the two futures: the "business-as-usual" Future 1 case that reflects current trends, and the "emerging technologies" Future 2 case, which is driven by assumptions that distributed generation, demand response, energy efficiency and energy storage will have a major effect on load and energy growth rates.

The motion came up short of the necessary two-thirds mark for approval with only 65.17% approval. The discussion was a carryover of an unresolved discussion during the January MOPC meeting. (See [SPP Members Delay Decision on 2021 Tx Assessment](#).)

ITC Holdings' Alan Myers, who chairs the Economic Studies Working Group that proposed the 60-40 split, said the weighting responded to concerns over favoring extra-high-voltage solutions without making a major change in the process. SPP has said a similar weighting would not have changed the results of the 2019 assessment. (See "MOPC Approves \$336 ITP Portfolio," [SPP MOPC Briefs: Oct. 15-16, 2019](#).)

Renewable interests favored a more aggressive forecast that incorporates additional energy growth. Others, wary of increasing



Greg McAuley, OG&E | © RTO Insider

transmission costs, favored the more conservative approach. Future 1 projects about 32 GW of wind installations by 2031, while Future 2 foresees about 37 GW.

"The more renewables you have, the more risk you have in building transmission due to the uncertainty of where the wind will be sited," said Golden Spread Electric Cooperative's Natasha Henderson. "I'm more confident of the transmission being built in Future 1."

"I'm concerned when you hear load-serving entities are committing their customers to these long-term assets," said McAuley, who has long expressed his concerns over escalating transmission costs and proposed a 70-30 split. "Being the Saudi Arabia of wind is absolutely a positive thing, but [SPP has] spent \$10 billion already in transmission. Our transmission rates are not going down. The question has to be who's going to be paying for the transmission in this tsunami of wind that's going to swamp this footprint."

American Electric Power's Richard Ross said the 50-50 consolidation would be the "appropriate rating," given customers demand for renewable energy.

"We have to look out for the benefits customers get from delivering these resources and building the backbone we need for the increased transition of our fleet," Ross said. "Some of you seemed to be quite happy with the [wind] facilities and construction of the system while meeting your needs. Now that we've gotten there, when we're trying to take steps to build the last miles on the eastern side of grid, you're opposed. That kind of mindset is short-sighted."

SPP's COVID-19 Load down 4-6%

SPP COO Lanny Nickell said the RTO will

SPP News



begin holding hourlong conference calls to update the MOPC on SPP's responses to the COVID-19 pandemic. The first members-only call, to protect confidential information, will be held next week.

Nickell said that like much of the rest of the electric industry, SPP has experienced a 4 to 6% reduction in load stemming from stay-at-home measures to halt the pandemic. The reductions have increased as temperatures have risen. The RTO has also noticed an uptick in canceled planned generation and transmission outages.

"There's a 30% reduction in capacity that is currently scheduled to be out over the next couple of months, compared to the same time frame in the last few years," he said.

In preparing his update, Nickell said he contacted each of the operations crews for their feedback.

"They said, 'We just want to stay healthy so [members] can continue to do their work. We know our members rely on us to keep the lights on,'" Nickell said.

In a follow-up [email](#) to stakeholders, CEO Barbara Sugg said SPP has not had a confirmed case of COVID-19 among staff. She said the organization has adapted to the pandemic — the web-only MOPC meeting attracted 229 attendees at one point — and is already developing plans to ensure a safe and orderly transition.

"Like the rest of you, our staff anxiously awaits the end of the pandemic and our collective return to business as usual," Sugg said.

Meter Ownership Still an Issue with Some

A Market Working Group recommendation to align the protocols with current metering standards was passed over the objections of several members who felt the revision request (RR 324) was not specific enough. A motion to endorse received six opposing votes and nine abstentions.

Several members pointed out market participants are not always the owners of the equipment they represent in the market and suggested replacing the term "market participant" with "asset owner" to more accurately represent who is responsible for the equipment.

"There's not specific identification of who is responsible for paying for things and testing for things in the meters. It puts the market participant as responsible for everything," said Tenas-



SPP CEO Barbara Sugg | © RTO Insider

ka Power Services' John Varnell. He said other SPP documentation and FERC documentation are more specific, laying similar responsibilities on the interconnection customer.

Richard Dillon, SPP market policy technical director, said market participants sign documents that clearly state they are responsible for the meter and are required to have meter agents.

"We don't know who owns it, who installed it, but the responsibility is on the market participant," Dillon said.

Grant, who initially opposed RR 324, said he was comfortable to move along with the change because of his confidence that "meter agent agreements will cover this."

MOPC Reorg '90%' Complete

Nickell said SPP is "about 90% there" in its reorganization of the MOPC's structure, which currently includes 16 working groups that report up to the committee's leadership.

Working with Chair Holly Carias and Vice Chair Denise Buffington, Nickell said they have divided the groups into the committee's primary responsibilities: markets, operations and planning. Their goal is to better align the group structure with SPP's primary functions and oversight responsibilities, focusing MOPC on policy-level work while letting the working groups take care of tactical issues.

The effort will result in the retirement of a couple of working groups, while others will be repurposed as user groups or advisory groups that "facilitate advice when advice is needed to be given to those functional areas," Nickell said.

For instance, the Business Practices Working Group will become the Transmission Service

User Group. Other user groups will include Generation Interconnection, Operations Training, Security and Change.

"We'll ensure ... the appropriate functions are in the right place," Nickell said. "This will facilitate a more effective and efficient approach to our work."

Some stakeholder groups will become advisory groups, including the Seams Steering Committee. That will incorporate seams oversight into applicable functional areas, Nickell said.

The Value and Affordability Task Force last year recommended the reorganization after eight months of study. The senior-level group was created to search for ways to increase SPP's value and improve affordability while maintaining and protecting its mission. (See [SPP Value Group Finds No 'Silver Bullets'](#).)

Saying he believes the benefits are "numerous," Nickell said staff are still working on a cost-benefit analysis.

MOPC leadership also plans to recommend improvements to the revision-request process. "We want to make it clearer and streamline it and ensure we have the appropriate inputs for policy," Nickell said.

The recommendations will be documented as a revision request, to be presented to MOPC during its July or October meetings.

SPP to Recommend Pausing Competitive Project

Casey Cathey, SPP director of system planning, told the MOPC that staff will recommend to the Board of Directors next week that they suspend a competitive, interregional project, pending FERC's approval of an agreement with Associated Electric Cooperative Inc. (AECI).

SPP and AECI have agreed to perform a joint study that will include a 345-kV competitive project approved in January by the board as part of the [2020 SPP Transmission Expansion Plan](#). The \$152 million, 105-mile Work Creek-Blackberry upgrade in Kansas and Missouri will be analyzed to determine whether there are any system reliability impacts. (See "SPP, AECI Agree to Joint Study," [SPP Seams Steering Committee: April 2, 2020](#).)

Cathey said SPP and AECI are developing a cost and usage agreement to execute once the joint study identifies whether the project will create any reliability issues. Should the study, which is expected to be completed in August, identify additional upgrades on the AECI system, staff will revisit the project with stakeholders and the Regional State Committee.

SPP News



“We recognize this potentially delays issuance of a [request for proposals], but there’s so much uncertainty with outside entities associated with FERC,” Cathey said. “FERC is probably the biggest wild card here, because of the coronavirus.”

He said the delay may push the project’s energization date back one or two months.

Members Approve 1 RAS, Retirement of Another

The MOPC unanimously approved its consent agenda, which included one revision request, a remedial action scheme (RAS) retirement and five project cost reset recommendations, but not before discussing separately the creation of another temporary RAS.

Members approved Xcel Energy’s recommended RAS to allow its 522-MW Sagamore Wind Farm in West Texas to interconnect with subsidiary SPS’ Crossroads substation before an additional 345/230-kV transformer at Tolk Station is in place. The RAS would monitor the 345-kV Crossroads-Tolk line’s current, tripping the wind farm when the current exceeds a specified level in place. The second 345/230-kV Tolk Station transformer is expected to be in service in March 2022.

Grant said the utility is working “diligently” to upgrade its system, at which point the RAS would no longer be needed. Nebraska Public Power District, Tri-County Electric Cooperative, Missouri River Energy Services and GridLiance opposed the motion, and 11 other members abstained.

The committee also asked the Transmission, Operating Reliability and System Protection and Control working groups to develop policy around future RAS schemes.

The consent agenda’s approval also resulted in the retirement of a RAS in effect at the Oklaunion Power Station in the Texas Panhandle since the mid-1980s. The plant itself is scheduled to be retired in October. (See [PSO Officially Retires Oklaunion Coal Plant.](#))

The Project Cost Working Group recommended baselines be reset for several previously approved projects. Three of the projects, located in North Dakota and belonging to Basin Electric Power Cooperative, were approved by FERC before Basin joined SPP in 2015 and are now in service.

The Basin projects included a nearly \$30 million decrease, to \$89.2 million, for a 70-mile, 345-kV line, a new switching station and an expanded substation; a \$36.6 million decrease,

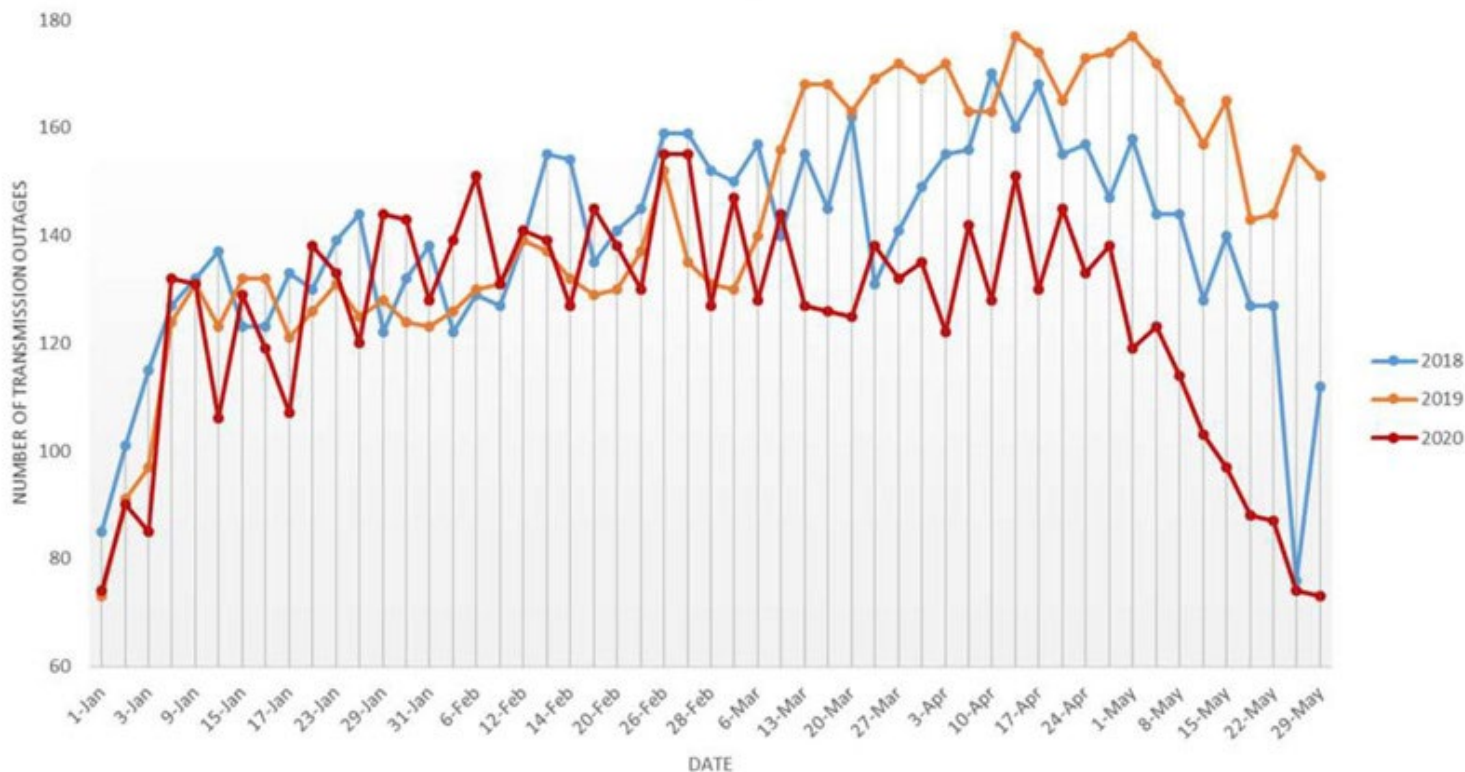
to \$95.7 million, for a 75-mile, 345-kV line, a new substation and necessary terminal upgrades; and a \$27.3 million decrease, to \$95.3 million, for a 58-mile, 345-kV line and new substation.

Other projects included:

- SPS’ reconfiguration of a 230-kV bus tie into a double-bus and breaker scheme in West Texas. The project’s costs have increased by \$8.5 million to \$19.7 million.
- Central Power Electric Cooperative’s 24-mile, 115-kV line in North Dakota. The project costs have dropped \$8.5 million to \$14.4 million.

The lone Tariff change request ([MWG-RR 383](#)) revises the Integrated Marketplace protocols’ mitigation requirements by clarifying that energy offers below \$25/MWh and operating reserve products below \$10/MWh are not subject to the mitigation process. It also makes clear that energy offers for locally committed resources are not subject to the normal mitigation process, but are capped at 10% above their mitigated offer and removes language requiring market participants to contact the Market Monitoring Unit before submitting an offer above their conduct threshold. ■

— Tom Kleckner



SPP’s forecast transmission outages for 2020, compared to the previous two years | SPP

Company Briefs

Brown to Lead MISO's Little Rock Office



MISO last week said it selected **Daryl Brown** to lead its South region office based in Little Rock, Ark.

Brown, who has roughly 30 years of experience in the industry, will serve as the primary internal and

external leader for MISO's South regional operations, customer management and government relations. He is also a member of the RTO's executive team that oversees regional customer integration efforts.

More: [Talk Business & Politics](#)

CenterPoint Completes Infrastructure Sale to PowerTeam



CenterPoint Energy last week announced it had completed

the sale of two natural gas distribution and transmission pipeline contractor businesses for \$850 million to PowerTeam Services, an infrastructure services provider to natural gas and electric companies.

The two businesses, Miller Pipeline and Minnesota Ltd., represented CenterPoint's infrastructure services arm. CenterPoint intends to use the proceeds to repay existing debts, it said. "The close of this transaction is a significant step in streamlining CenterPoint Energy's operations and driving our strategy of growing our core utility operations," said John W. Somerhalder II, interim president and CEO.

PowerTeam now holds revenues of approximately \$2 billion, making it a leading construction and maintenance services provider in the natural gas and electric market in the U.S.

More: [CenterPoint Energy; International Comparative Legal Guides](#)

Salt River Project, Seattle City Light Can Now Dispatch into EIM

Two western municipal power generators, the Phoenix-area's Salt River Project and Seattle City Light, announced they have officially joined CAISO's Energy Imbalance Market. Together they serve roughly 1.5 million customers.

EIM entities represent 61% of the load in the Western Electric Coordinating Council

and have enjoyed benefits of more than \$861 million since its launch in November 2014, according to CAISO.

"Seattle City Light and Salt River Project's participation in the EIM proves regional collaboration generates meaningful savings to many public and investor-owned utilities and drives grid modernization through the effective integration of renewable resources," ISO President and CEO Steve Berberich said.

More: [Power Engineering Magazine](#)

Tri-State OKs New Self-supply Option for Utility Members



TRI-STATE

Tri-State Generation & Transmission Association's board of

directors said last week it may allow utility members to self-supply up to 50% of their load requirements pending FERC approval.

The board approved a new partial-requirements contract option allowing members to add local renewables capacity and increase their self-supply of power. Utilities willing to take advantage of the contract option can participate in an upcoming open-season period to allocate 300 MW of systemwide member self-supply capacity.

"Both the partial requirements contract option and the contract termination payment methodology approved by the board protect the interests of all Tri-State utility members by ensuring that one member's action does not unfairly shift costs to the other members," CEO Duane Highley said.

More: [Renewables Now](#)

Vistra Announces Expansion of Oakland Battery Storage Facility



Vistra Energy last week announced it is increasing the size of its battery

energy storage project at the Oakland Power Plant from 20 MW to 36.25 MW. The company anticipates the storage project will be commercial operational by January 2022.

The battery system will be a partial replacement for the aging 165-MW jet-fuel-fired plant, which is currently on a reliability-must-run contract with CAISO. Vistra plans to eventually retire the existing units and develop additional storage projects on the site.

More: [Vistra Energy](#)

Vogle Workforce Reduced by 20%



Georgia Power announced last week it would reduce the workforce at Plant Vogtle Units 3 and 4 by approximately 20% (about 1,800 people) as part of a

mitigating action "intended to address the impact of the COVID-19 coronavirus on the workforce and construction site." As of last week, at least 35 workers at the site had reportedly tested positive for COVID-19.

The Vogtle expansion has experienced numerous delays and cost overruns since the original engineering, procurement and construction contract was signed in April 2008. Then, the guaranteed substantial completion dates were April 2016 and April 2017 for Units 3 and 4. Now, the regulatory-approved in-service dates are November 2021 and November 2022.

More: [POWER Magazine](#)

FERC: PGE Order 845 Filing Needs Work



FERC last week partially accepted Portland General Electric's latest

Order 845 compliance filing but ordered more changes.

PGE first filed proposed revisions to its tariff in May 2019 in compliance with the requirements of FERC Orders 845 and 845-A, issued in 2018 to increase the generator interconnection process' transparency and speed. In November, the commission found the proposed revisions failed to "detail the specific thresholds or criteria that Portland General would use as part of its method to identify contingent facilities."

FERC partially accepted its changes Thursday, but it also told PGE that its filing needs work. "Portland General's proposed tariff revisions do not state the specific thresholds or criteria that would result in the transmission system demonstrating unacceptable pre- and post-contingency system performance," the commission wrote. It ordered PGE to refile within 120 days.

More: [ER19-1927](#)

FERC OKs Settlement on SPS Rates

FERC on Monday approved an uncontested settlement over Southwestern Public Ser-

vice's revisions to its formula rate template. The settlement implements an adjustment for unfunded reserves; revises SPS' depreciation rates and commits the company to not seek changes to those rates before Nov. 1; implements the template's base plan upgrade revenue requirement calculation using a weighted average transmission depreciation rate; and withdraws SPS'

proposal to directly assign to its wholesale transmission service customers certain regulatory commission expenses recorded to Account 928. SPS also agreed to amortize for accounting purposes and flow back in rates, based on the average rate assumption method, excess plant-related protected accumulated deferred income tax (ADIT) balances and excess plant-related unpro-

tected ADIT balances.

SPS' original proposed template was challenged in protests by Golden Spread Electric Cooperative; GridLiance High Plains; Tri-County Cooperative; Western Farmers Electric Cooperative; and West Texas Municipal Power Agency.

More: [ER19-404-002](#)

Federal Briefs

Clean Energy Sector Shed 106,000 Jobs in March

Based off analysis of Department of Labor unemployment claims published by BW Research last week, the clean energy sector lost more than 100,000 jobs in March as strict measures to control the COVID-19 pandemic shut down manufacturing and halted plans for home and business upgrades.

There were 3.36 million workers in the sector at the end of 2019, an increase of more than 70,000 from 2018. The March job losses erased the industry's gains and more. Furthermore, the analysis projects that more than 500,000 jobs could be lost in the next few months.

The clean energy sector includes solar and wind company workers, electricians, roofers and plumbers who install energy-efficient products, and factory employees who make hybrid cars and efficient appliances.

More: [Reuters](#)

EPA Weakens Controls on Mercury



EPA last week weakened regulations on the release of mercury and other toxic metals from oil- and coal-fired power plants. The new rule does not eliminate the restric-

tions, but instead creates a new method of calculating the costs and benefits of curbing mercury pollution.

"Under this action, no more mercury will be emitted into the air than before," EPA Administrator Andrew Wheeler claimed.

Patrick Parenteau, a professor at the Vermont Law School, noted that in virtually every environmental rollback, EPA has acknowledged in the fine print that enormous increases in health problems and deaths will occur because of increased pollution.

A plan to weaken carbon dioxide emissions at power plants, for example, predicted as many as 1,400 additional premature deaths a year. A draft analysis of the soot policy put forward last week showed that tightening the existing standard by 25% could save as many as 12,150 lives a year.

More: [The New York Times](#)

NM Wind Farm Environmental Review Finished

The Bureau of Land Management last week finished an environmental review of a planned 100-MW Borderlands Wind Farm near the Arizona-New Mexico border, setting a deadline of May 11 to file comments and protests.

Under the agency's preferred alternative, the wind farm would include 34 turbines on 24 square miles of federal land southwest of Quemado, N.M. Aside from turbines that will be limited to a height of 630 feet, the farm will include access roads, transmission lines and a substation.

Residents have been worried about the lack of economic benefits, as well as the degradation of property values, views, the night sky and negative effects on avian species.

More: [The Associated Press](#)

Republican Senators Want Coal to Get Bailout Money



A group of 17 Republican senators last week sent a letter asking Federal Reserve Chairman **Jerome Powell** and Treasury Secretary Steve Mnuchin to ensure fossil fuel companies are not left out of the

COVID-19 bailout program being administered by BlackRock.

The letter calls for the government to

ensure the relief program is "broad and flexible" and says companies in the "energy and transportation sectors" deserve support. However, in January, BlackRock decided to exclude any company from its actively managed holdings if it derives more than 25% of its revenue from selling coal used in power plants. In fact, last month BlackRock Chairman Larry Fink used a letter to shareholders to argue the pandemic should be used by investors as an "opportunity to accelerate into a more sustainable world."

BlackRock, the world's largest asset manager, has become the buyer of corporate bonds as part of a \$454 billion effort to bail out companies hit by the pandemic.

More: [Bloomberg Environment](#)

Trump Admin Again Removes Tariff Exemption for Bifacial Solar Panels

The Trump administration last week said it will once again withdraw an exclusion it had previously granted to bifacial solar panels after determining it "is undermining the objectives" of the Section 201 tariffs placed in January 2018.

Companies that had invested in U.S. manufacturing plants in the wake of the tariffs had opposed the exclusion and argued it helped internationally manufactured panels undercut domestically products. Before the administration withdrew the exemption in October, Invenenergy Renewables filed a legal challenge and argued that the U.S. trade representative did not allow for proper comment or notice. In December, the U.S. Court of International Trade sided with Invenenergy and allowed the exclusion to stand, though in January, the administration restarted the process by requesting comment on the future of the exclusion.

The Solar Energy Industries Association said it would continue to pursue litigation related to the exclusion. If additional legal challenges follow, the fight could last as long as the

tariffs themselves (2022).

More: [GreenTech Media](#)

Trump Officials Reject Stricter Air Quality Standards



EPA Administrator **Andrew Wheeler** announced last week the agency would maintain its current standards for fine particulate matter (soot) despite scientific evidence linking air pollution to lethal outcomes from respiratory diseases such as COVID-19, saying, "We believe the current standard is protective of public health."

The agency's staff scientists recommended lowering the annual particulate matter standard to 8 to 10 micrograms per cubic meter last year, citing estimates that reducing the limit to 9 could save about 12,200 lives a year. Furthermore, a study published this month by researchers in Harvard University's T.H. Chan School of Public Health examined 3,080 counties and found that an increase in long-term exposure to fine particulate pollution of just 1 microgram per

cubic meter is associated with a 15% greater likelihood of dying of COVID-19.

More: [The Washington Post](#)

WoodMac Reduces 2020 Solar Installs Forecast



Wood Mackenzie last week cut its 2020 global solar installations forecast by 18% (23 GW) to 106.4 GW to reflect the impact of the COVID-19 pandemic. WoodMac also recently reduced its global energy storage capacity deployments forecast for this year by 19% (3 GWh).

The market research company expects the pandemic to impact 2021 as well, as it now anticipates next year's solar capacity additions to be about 123.6 GW (down from 127.2 GW).

More: [Renewables Now](#)

FERC Rejects Rehearing of ADIT Rule

FERC on Thursday rejected requests for rehearing of Order 864, issued in November to implement the Tax Cuts and Jobs Act. The order required transmission owners to mod-

ify the accumulated deferred income taxes (ADIT) incorporated in their rates to reflect the December 2017 law, which lowered the corporate income tax rate from 35% to 21%.

Exelon's utilities challenged the order's requirement that excess ADIT be "wholly preserved" until a utility's transmission formula rate contains a mechanism to flow the amount through rates to customers. The companies argued that the provision conflicted with an earlier commission ruling on their request to recover past deficient ADIT amounts resulting from state corporate income tax rate increases prior to the federal decrease.

FERC flatly denied the companies' request, saying that excess ADIT is different from deficient ADIT. "Simply, the commission rejected Exelon companies' attempt to recover the full amount of past deficient ADIT because Exelon companies failed to meet the next rate case requirement of Order No. 144," the commission said. "Order No. 864 does not address past deficient ADIT, nor does it change the requirements of Order No. 144."

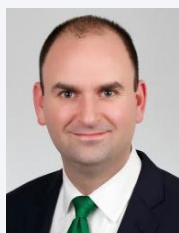
More: [RM19-5-001](#)

State Briefs

REGIONAL

Electricity Prices Reach New Lows as Coronavirus Cuts New England Demand

Electricity demand in New England has dropped between 3 and 5% during the COVID-19 outbreak, ISO-NE said last week.



The drop in demand has led to lower electricity prices, which were already low because of a mild winter and more renewable energy. Power prices are running at "probably less than \$20/MWh, compared with a

more typical price in the upper \$20 to lower \$30 range," said New England Power Generators Association President **Dan Dolan**.

Residents and businesses across the region are using electricity at different times than before in response to the coronavirus, causing load patterns to resemble those of snow

days when schools are closed and many are home. Eversource Energy spokesman Mitch Gross said residential power in Connecticut rose 3% between March 21 and 27 compared with the previous week, while consumption dropped 3% for commercial and industrial customers.

More: [Hartford Courant](#)

Fishing Industry Group Seeks Pause on Offshore Wind Planning

The Responsible Offshore Development Alliance, a fishing industry group, sent a letter to the governors of Maine, New Hampshire and Massachusetts last week requesting a six-month halt on the federal planning process for putting wind turbines in the Gulf of Maine.

Their letter stated concerns that efforts to fight the COVID-19 pandemic will limit the public's ability to weigh in on the process. Officials say it will likely be a decade before any wind project comes to fruition.

More: [New Hampshire Public Radio](#)

ARKANSAS

LM Wind Power to Close Little Rock Plant



LM Wind Power last week said it will close its wind blade

manufacturing plant at the Port of Little Rock later this year amid declining demand. The company said the decision is not related to the COVID-19 outbreak and will pay 470 workers for a minimum of four months.

More: [Arkansas Business](#)

CALIFORNIA

Marin Power Shutdowns Continue Despite Stay-home Order

Pacific Gas and Electric is proceeding with plans to cut power to Marin residents to complete work it deems essential to prepare for the wildfire season. The decision comes after the utility pledged to cease all shutdowns and posted a notice on its website

on March 16.

Despite the decision, some residents received notices from PG&E saying it planned to cut power on other days as well during the period it promised to keep the electricity on.

PG&E spokeswoman Deanna Contreras said, "As PG&E continues with critical and essential safety and maintenance projects, we will minimize customer impacts to the extent possible. Where service interruptions are required to safely complete critical and essential work, PG&E pledges to limit the number and duration of planned outages, to the extent possible." She also said there are about 18 power shutoffs planned in Marin through the end of the month.

More: [Marin Independent Journal](#)

KANSAS

Crawford County Approves Wind Farm Plans



The Crawford County Commission last week approved several agreements with Apex Clean Energy in regard to its Jayhawk Wind project, a wind power project in northwestern Crawford and southwestern Bourbon counties.

The agreements approved include development, road use, complaint resolution, county contribution and decommissioning agreements.

Crawford County does not have zoning regulations that govern the area where the project is planned and therefore the commission's role is limited to ensuring the agreements are fair and the county and its residents are protected.

More: [The Morning Sun](#)

MAINE

Sedgwick Solar Farm Gets Planning Board Approval

The Sedgwick planning board last week unanimously approved the site plan review application for the Borrego Solar Project. If the project is accepted into a state solar program this summer, construction would begin in the spring of 2021.

Even with planning board approval, hurdles (mainly being accepted into the solar program) exist. One concern raised by board member Peter Neill was over property taxes.

All state permits have been approved. An

interconnectivity agreement with Emera Maine has been submitted to the Public Utilities Commission for approval.

More: [The Weekly Packet](#)

MICHIGAN

PSC Approves DTE Electric's Revised IRP



The Public Service Commission last week approved a revised integrated resource plan for DTE Electric. The company said it agreed to adopt changes recommended by the PSC and has adjusted the plan over the next 15 years accordingly.

Among the changes DTE agreed to adopt were: expanding programs to help customers cut energy waste through more efficient appliances, insulation and equipment; increasing its annual energy savings goals to 1.75% and 2% in 2020 and 2021, respectively; conducting further analysis of the proposed retirement of the coal-fired Belle River power plant in 2029-2030; and filing its next IRP two years sooner than required by Sept. 21, 2023.

More: [Michigan PSC](#)

MISSISSIPPI

PSC Permits Recurrent Energy's BTA with Entergy

The Public Service Commission last week approved Recurrent Energy's build-transfer agreement (BTA) with Entergy Mississippi for the \$138 million, 100-MW Sunflower solar project.

As per the agreement, Recurrent Energy will develop the solar project on approximately 1,000 acres of land in Sunflower County. Entergy will then own the plant once it becomes operational in mid-2022.

More: [Power Technology](#)

MONTANA

'Zoombombing' Shuts Down PSC Meeting



The Public Service Commission fell victim to teleconference hijacking, or "zoombombing," which interrupted public comment and delayed commissioners' decision-making.

During a regular meeting, Rep. Mary Ann

Dunwell was giving public comment on NorthWestern Energy's application to buy an added share in the Colstrip Unit 4 when someone interrupted her and said, "No one wants to hear your [expletive] [expletive]." When it came time for the PSC to consider NorthWestern's purchase proposal, PSC attorney Zach Ragala suggested commissioners postpone.

The FBI released a warning about the rising trend of people interrupting teleconferences. It has become a problem across the country as more and more people, school districts and government groups turn to remote meetings.

More: [Montana Public Radio](#)

VIRGINIA

Regulators Approve Old Dominion Power Rate Increase

The State Corporation Commission last week approved a rate increase for Old Dominion Power to increase its annual revenue by \$9 million. The company estimated the average residential customer using 1,250 kW will see their monthly bill rise 15.4%.

Old Dominion argued that the increase was necessary to "ensure safe and reliable energy service," provide shareholders with a fair rate of return and offset the loss of nine municipal customers from the rate base. The \$9 million increase is almost 30% lower than the utility's initial request of \$12.7 million.

"The longer a company goes without being able to recover its costs, it will only lead to higher future rate increase requests. Current law only permits a company one base rate increase in a 12-month period," said SCC Division of Information Resources Director Ken Schrad.

More: [Virginia Mercury](#)

WASHINGTON

Puget Sound Energy to Provide Relief for Those Impacted by Pandemic

Puget Sound Energy last week said its Crisis-Affected Customer Assistance Program, which will include \$11 million in funds, will offer financial relief and be open to those who have been laid off or had hours cut because of the spread of COVID-19.

To qualify for assistance, customers must have a monthly income less than 250% of the federal poverty level and live in one of 10 counties. Those eligible could receive up to \$1,000 in utility bill credits.

More: [SeattlePI](#)

WYOMING

Energy Authority Board Elects Leaders

The newly formed state Energy Authority's board of directors held its first meeting last week via videoconference and elected leaders for the upcoming term.

The newly elected leaders included Chairman Mark Stege, Black Hills Energy; Vice Chairman Paul Ulrich, Jonah Energy; and Secretary Wendy Hutchinson, Lighthouse Resources.

The agency is tasked by Gov. Mark Gordon and the Legislature to develop, adminis-

ter and communicate the state's energy strategy. Priorities include diversifying and expanding the energy economy and facilitating permitting, production, development and transmission of energy.

More: [Wyoming Tribune Eagle](#)

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