RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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Fire Victims Challenge PG&E Deal as Vote Looms

By Hudson Sangree

The $13.5 billion settlement that Pacific Gas and Electric struck with wildfire victims may be in trouble, threatening one of the main components of the utility's plan to exit bankruptcy by the end of June.

Judge Dennis Montali | *Commercial Law League of America*

On Monday, the official Tort Claimants Committee (TCC), which represents the majority of the case's 70,000 fire victims, petitioned U.S. Bankruptcy Judge Dennis Montali to allow it to send out a letter asking victims to postpone voting on the utility's Chapter 11 reorganization proposal until at least May 1 because of "problems and risks the TCC has identified with PG&E's plan."

PG&E and lawyers representing the case's second-largest group of fire victims objected. Montali scheduled a hearing on the matter for this morning.

The surprise move came after three members of the TCC, composed of 11 fire victims, resigned so they could openly criticize PG&E's plan to fund the $13.5 billion trust with $6.75 billion in company stock. They fear the shares could decline in value, especially now that the COVID-19 coronavirus pandemic is pummeling stock markets worldwide.

"The TCC believes that the … coronavirus' economic ripple effect presents an unforeseeable and significant risk that the shares of stock will not have the value necessary to match the $13.5 billion that PG&E has stated would be available to pay fire victim claimants," the committee's lawyers wrote.

Robert Julian | *Baker-Hostetler*

The victims' attorneys had been trying to get PG&E to guarantee the full amount, regardless of stock market changes, but mediation to resolve the matter broke down March 27, attorney Robert Julian said in the motion to Montali.

"The TCC believes the parties have not made any substantial progress, and the TCC believes it is important that the proposed letter be

Continued on page 7

ISO-NE Sending 2 Energy Security Plans to FERC

By Michael Kuser

ISO-NE will file two versions of its Energy Security Improvements market design with FERC later this month after the New England Power Pool Participants Committee on Thursday approved a modified version of the RTO's plan that seeks to reduce its cost to consumers.

ESI would allow the RTO to procure energy call options for three new day-ahead ancillary service products to improve the region's energy security, particularly in winter when natural gas shortages can leave generators without fuel. Option awards will be co-optimized with all energy supply offers and demand bids in the day-ahead market.

The PC approved three amendments by the New England States Committee on Electricity

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Danly Sworn in; Morenoff Named Acting General Counsel

Judge Danny J. Boggs swears in former FERC General Counsel James Danly as a commissioner as his wife, Frankie, looks on. (p.4) | *FERC Chair Neil Chatterjee*

COVID-19 RESPONSE

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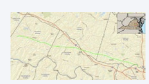

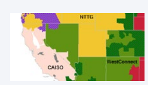

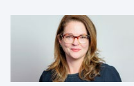

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In this week's issue

FERC/Federal News

FERC Loosens Requirements in Pandemic

Waivers, Delegations of Authority

By Rich Heidorn Jr.

FERC on Thursday issued a flurry of orders delegating authority and waiving requirements in response to the COVID-19 coronavirus pandemic.

The commission issued:

- A policy statement saying it will "expeditiously review and act on requests for relief" to ensure the business continuity of regulated entities' energy infrastructure (*PL20-5*).
- An order delegating authority to the director of the Office of Energy Market Regulation (OEMR), or the director's designee, "to take action on uncontested requests for waiver of certain regulatory obligations to address needs resulting from steps entities have taken to meet the emergency conditions" (*AD20-13*). The delegation will be effective until June 1.
- An order delegating authority to the director of the Office of Energy Policy and Innovation, or the director's designee, to act on requests for extension of filing deadlines or waivers of the requirements of FERC Form 552 (Annual Report of Natural Gas Transactions) and FERC-730 (Report of Transmission Investment Activity). This authority was previously delegated to the director of the Office of Enforcement (*RM20-13*).
- An order extending until Oct. 20 the deadlines for RTOs and ISOs to post monthly reports that would have been due between April and September on uplift and operator-initiated commitments (*RM17-2*). (See *FERC Orders RTOs to Shine Light on Uplift Data*.)
- An order granting a blanket waiver through Sept. 1 of requirements to hold meetings in-person and obtain notarized documents in any tariff, rate schedule, service agreement or contract subject to the commission's jurisdiction under the Federal Power Act, the Natural Gas Act or the Interstate Commerce Act (*EL20-37*). NYISO had requested relief from the notary requirements on March 27 (*ER20-1419*).

FERC has already granted PJM's request for a waiver of generator interconnection-related deadlines (*ER20-1392*).

The commission said its delegation to OEMR will allow more efficient action on uncontested waiver requests. "The need for efficient processing and action is particularly important given the emergency conditions related to COVID-19, as entities may need to seek waiver of various requirements with which they are unable to comply due to the extraordinary circumstances," the commission said.

It said the waiver "does not permit violations of the filed rate doctrine and the rule against retroactive ratemaking, even in uncontested cases. If such questions arise, they will be considered by the commission."

The policy statement noted that the entities subject to FERC regulation "have had to take unprecedented actions in response to the emergency conditions, including directing staff to work remotely for an extended period, which may disrupt, complicate or otherwise change their normal course of business operations."

"We will give our highest priority to processing filings made for the purpose of assuring the business continuity of regulated entities' energy infrastructure during this extraordinary time," the commission continued. "We view the reliability and security of our nation's vital energy infrastructure as critical to meeting the energy requirements essential to the American people." ■

FERC headquarters | © *RTO Insider*

FERC/Federal News

Danly Sworn in; Morenoff Named Acting General Counsel

By Michael Brooks

James Danly was sworn in as a FERC commissioner March 31, officially beginning a term to end in 2023 and giving Republicans a 3-1 advantage on the commission.

Danly, who had been serving as general counsel for the commission since September 2017, was sworn in by 6th U.S. Circuit Court of Appeals Judge Danny J. Boggs, for whom he once served as law clerk.

Judge Danny J. Boggs swears in former FERC General Counsel James Danly as a commissioner as his wife, Frankie, looks on. | *FERC Chair Neil Chatterjee*

"I'm so glad to have James join my colleagues and me as a commissioner, particularly as FERC is dealing with many pressing issues related to the COVID-19 pandemic in addition to continuing the important work of the agency," FERC Chairman Neil Chatterjee said. "The commission and the American people will benefit from Commissioner Danly's viewpoint on the many issues that we now have before us."

"Welcome to FERC Commissioner James Danly! I look forward to working with him in his new capacity," tweeted Commissioner Richard Glick, the lone Democrat.

"Congratulations to James Danly on being sworn in as a commissioner at FERC," Commissioner Bernard McNamee tweeted. "He has been a valued adviser while general counsel and will be a great colleague on the commission."

The U.S. Senate confirmed Danly's nomination to the commission March 12. (See *Senate Confirms Danly to FERC*.) He fills a seat left open by the death of Commissioner Kevin McIntyre in January 2019. McNamee, whose term ends June 30, has said he would stay on until a replacement for his seat is confirmed or the end of the year.

To replace Danly — at least temporarily — Chatterjee named Deputy General Counsel David Morenoff as acting general counsel.

"David is a consummate professional and outstanding lawyer," Danly said. "I have relied on his wise counsel since the beginning of my tenure at FERC. I appreciate his willingness to accept this role and am confident that he will provide much-needed continuity during these difficult times." ■

FERC/Federal News

FERC Stands Firm on Form 715 Assessments

By Rich Heidorn Jr.

FERC said Friday that PJM must rebill parties with interest to reverse incorrect cost assignments for transmission projects to meet individual utilities' planning criteria.

In 2015, the commission approved a PJM Tariff change that assigned 100% of the costs of Form 715 transmission projects to the sponsoring utility's ratepayers. But FERC reversed itself last August after the D.C. Circuit Court of Appeals said it had erred.

The court said FERC's approval was "arbitrary" and would result in a "severe misallocation of the costs" of projects that have regional benefits. (See *FERC Opens Local Tx Projects to Competition, Cost Sharing*.)

The commission on Friday rejected rehearing on its August order and clarified that PJM should issue refunds dating back to May 25, 2015, with interest (*ER15-1387-005, ER15-1344-006*).

The commission rejected arguments by Linden VFT and Consolidated Edison Company of New York that the commission should have limited its remand order to high-voltage facilities.

"PJM's Tariff uses the solution-based DFAX [distribution factor] method to determine whether transmission facilities have benefits outside of the zone of the transmission owner constructing the project and allocates costs to zones based on the application of that methodology," FERC said. "Because the benefits of lower-voltage facilities may accrue to other zones, we do not see a basis for limiting cost allocation for lower-voltage facilities planned under Form No. 715 local planning criteria to only the local zone of the constructing transmission owner."

Linden also sought rehearing on the issue of refunds, arguing that the commission's "default" policy is to reject refunds in cases of rate design.

The commission responded that it "does not have a general policy concerning refunds" but makes decisions based on each case individually.

"Here, the commission has found the facts and equities favor refunds," it said. "For example, requiring refunds in this case requires only redetermining past payments; it does not involve the difficult issues often associated with the rerunning of auctions."

The commission on Friday also accepted PJM's compliance filing with *revised cost responsibility assignments* to correct the allocations made under the 2015 Tariff amendments (*ER15-1387-006, ER15-1344-007*).

PJM said it identified 443 transmission projects that had been assigned 100% to the zone of the TOs filing the Form 715 planning criteria between May 25, 2015, and the remand order on Aug. 30, 2019. It determined that it needed to revise allocations for 44 of the projects.

The new allocations reassigned costs for several projects in the Public Service Electric and Gas zone to Con Ed, East Coast Power, Neptune Regional Transmission System, Rockland Electric, PECO Energy and Jersey Central Power & Light.

Dominion Energy, which had been assessed for 100% of the rebuild of the Elmont-Cunningham 500-kV line, is now sharing the cost with 23 other utilities. ■

Dominion Energy replaced a 500-kV line between the Cunningham and Elmont substations. | *Dominion Energy*

CAISO/West News

California PUC Adopts Electrification Pilot Programs

$200M Program to Prioritize Low-income Housing

By Hudson Sangree

The California Public Utilities Commission has established two building decarbonization pilot programs to jump start the state's electrification of residential structures, devoting $200 million toward the effort.

The Building Initiative for Low-emissions Development (BUILD) program and the Technology and Equipment for Clean Heating (TECH) initiative were created under Senate Bill 1477, which the State Legislature passed in 2018. Lawmakers tasked the commission with implementing the programs.

"These two pilot programs are designed to develop valuable market experience for the purpose of decarbonizing California's residential buildings in order to achieve California's zero-emissions goals," Commissioner Liane Randolph wrote in her *proposed decision*, which the commission adopted March 26.

"The BUILD program and TECH initiative are building decarbonization pilot programs intended to raise awareness of building decarbonization technologies and applications, test program and policy designs, and gain practical implementation experience and knowledge necessary to develop a larger scale approach in the future," the CPUC said.

The move comes amid efforts by some cities to require electrification of new, and in some circumstances, existing structures. Eliminating furnaces and water heaters that use natural gas could contribute significantly to California's efforts to become carbon-neutral by midcentury, advocates contend. (See *West Coast Pushes for Building Electrification*.)

The BUILD program is meant to incentivize technologies in new residential buildings that reduce greenhouse gas emissions well beyond the requirements of the state's building and energy codes.

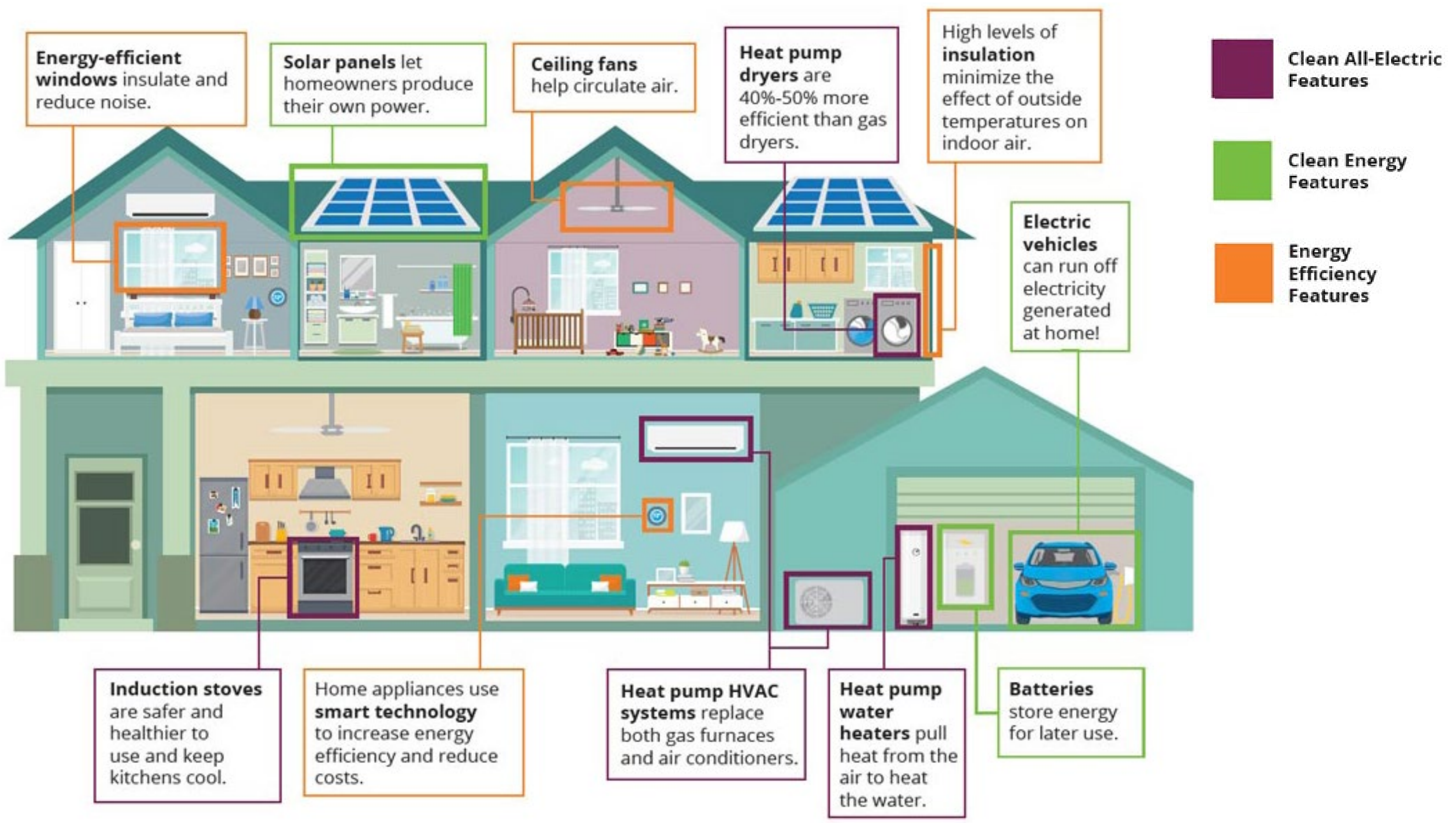
The California Energy Commission will administer the program with CPUC oversight. At least 30%, or $60 million, of the total $200 million must be earmarked for new low-income housing under SB 1477.

"This percentage is not the ceiling for spending on low-income housing, but rather the floor," the proposed decision says.

"The CEC should aim to design the BUILD program with the goal to deploy near-zero emission building technologies in the largest number of new residential housing units possible," it says.

The TECH initiative is intended to promote the adoption of space heating and water heating equipment powered by electricity instead of gas in new and existing residential structures. A third party, still to be selected, will implement the program, with specific technologies still to be identified, the CPUC said.

"To accelerate market development and adoption of building decarbonization technologies targeted under the TECH initiative, we allow the implementer discretion to consider or build upon an array of tactics and approaches," the CPUC said. "We decline to adopt a prescriptive list of eligible technologies and products until an implementer is selected." ■



Replacing traditional gas appliances such as water heaters with electric units is a key goal of electrification. | *Edison International*

CAISO/West News

Fire Victims Challenge PG&E Deal as Vote Looms

Continued from page 1

sent to fire victim claimants disclosing such issues," it said. "The information provided in the proposed letter may have a material impact on how and when fire victim claimants vote."

'Complete Lack of Transparency'

In a statement Monday, PG&E took issue.

"The TCC's filing is an attempt to change the settlement it agreed to despite the fact that the agreement has the broad support of the parties and the governor's office and is the best and fastest path to getting victims paid," the utility said. "The TCC's effort to recut the deal puts at risk their clients' ability to be paid quickly."

The TCC's move appeared to be partly a response to a growing grassroots movement among wildfire victims to oppose the $13.5 billion deal reached in December. (See *PG&E Reaches $13.5B Deal with Wildfire Victims*.)

Lawyers stand to be paid 30 to 40% of the trust amount.

The latest fire victim to resign from the TCC told the *Associated Press* that attorneys had violated their fiduciary duty to clients by hiding the risks of funding half the trust with PG&E stock.

"They're just not breaching their fiduciary duty; they're blowing it up," Karin Gowins said. "There has been a complete lack of transparency."

Gowins was the comptroller of Paradise, Calif., the town of 27,000 largely destroyed by the Camp Fire in November 2018 after a PG&E high-voltage line ignited the state's deadliest and most destructive wildfire, killing 85.

State fire investigators have also determined that PG&E equipment started the deadly Northern California wine country wildfires of October 2017 and the Butte Fire, in the Sierra Nevada foothills near Sacramento, in September 2015.

Since filing for bankruptcy in January 2019, PG&E has reached settlements with fire victims, insurance companies and local governments worth $25.5 billion and won Gov. Gavin Newsom's approval for its restructuring plan. The dispute over the fire victims' settlement threatens to undermine its efforts.

National Guard soldiers search for human remains in the rubble of the Camp Fire, which tore through Paradise, Calif., on Nov. 8, 2018. | *California National Guard*

Plaintiffs' Lawyers at Odds

In its proposed letter, which requires the judge's approval, the TCC says PG&E revised its agreement with fire victims by increasing its debt load and lowering the amount of cash it expects to raise by issuing stock. The changes were made without fire victims' consent, it says.

"Both of those changes impact the value of PG&E's stock," it says.

The TCC's proposal would give PG&E until April 28 to resolve the outstanding issues; lawyers would notify victims of the status of negotiations by May 1.

Disclosure statements outlining PG&E's plan and ballots are being sent to fire victims and other creditors, with a voting deadline of May 15.

In a motion opposing the TCC's request, two lawyers representing about 7,000 fire victims say the motion is an ill-timed attempt to sway the voting.

Gerald Singleton | *Gerald Singleton*

"The content of the proposed letter interferes with the bankruptcy principle that claimants should be free to exercise their voting rights after being provided a neutral statement approved by the court. The court should deny TCC's request that it put its 'finger on the scale' by entering an order approving the proposed letter after voting has already commenced," Gerald Singleton and Richard Marshack said.

The TCC lawyers, however, argued the proposal is a familiar move in bankruptcy proceedings.

"Committees often inform their constituents of their views on various aspects of bankruptcies," they said. "Mass tort cases are no exception."

PG&E is trying to exit bankruptcy by June 30 to participate in a state wildfire insurance fund established last year. Its agreement with Newsom would allow the state or a third party to take over the utility if it doesn't meet that deadline. Montali has yet to approve that agreement, which he's scheduled to hear today. ■

CAISO CRRs Still Losing Money, but Less

Department of Market Monitoring Recommends Ending Auctions

By Hudson Sangree

CAISO's congestion revenue rights auction continued to lose money in 2019 but significantly less than in prior years, the ISO's Department of Market Monitoring said in a recent report to the Board of Governors.

Even so, the department, a longtime critic of the CRR auctions, still wishes the ISO would get rid of CRRs or at least take ratepayers, who are unwittingly covering tens of millions of dollars in annual losses, out of the equation.

"Rule changes made by the ISO reduced losses from sales of congestion revenue rights significantly in 2019," DMM Executive Director Eric Hildebrandt wrote in a memo to the board. "However, DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights on behalf of transmission ratepayers.

"If the ISO believes it is highly beneficial to actively facilitate hedging of congestion costs by suppliers, DMM recommends that the ISO modify the congestion revenue rights auction into a market for financial hedges based on clearing of bids from willing buyers and sellers," Hildebrandt said.

From 2009 to 2018, CAISO's CRR auctions resulted in net losses of more than $800 million for transmission ratepayers, Hildebrandt said in his March 25 *update* to the board. (Hildebrandt's memo was a summary of a more detailed *report* filed Jan. 27.)

Revenues collected in the auction worked out to about 50 cents on dollars paid out, it said. Losses from sales of CRRs totaled $100 million in 2017 and $131 million in 2018, the DMM said. (See *CAISO Q4 CRR Revenues Falling Short After Summer Surplus*.)

Starting in 2019, CAISO instituted rule changes meant to stanch the flow of money from ratepayers to commodities traders. The rule changes reduced losses significantly last year in conjunction with lower congestion on the grid, the department said.

Losses from sales of CRRs totaled approximately $34 million in 2019, including $22 million in the fourth quarter alone. Transmission ratepayers took in about 68 cents on each dollar paid out, while financial entities reaped $33 million in profits, the department said.

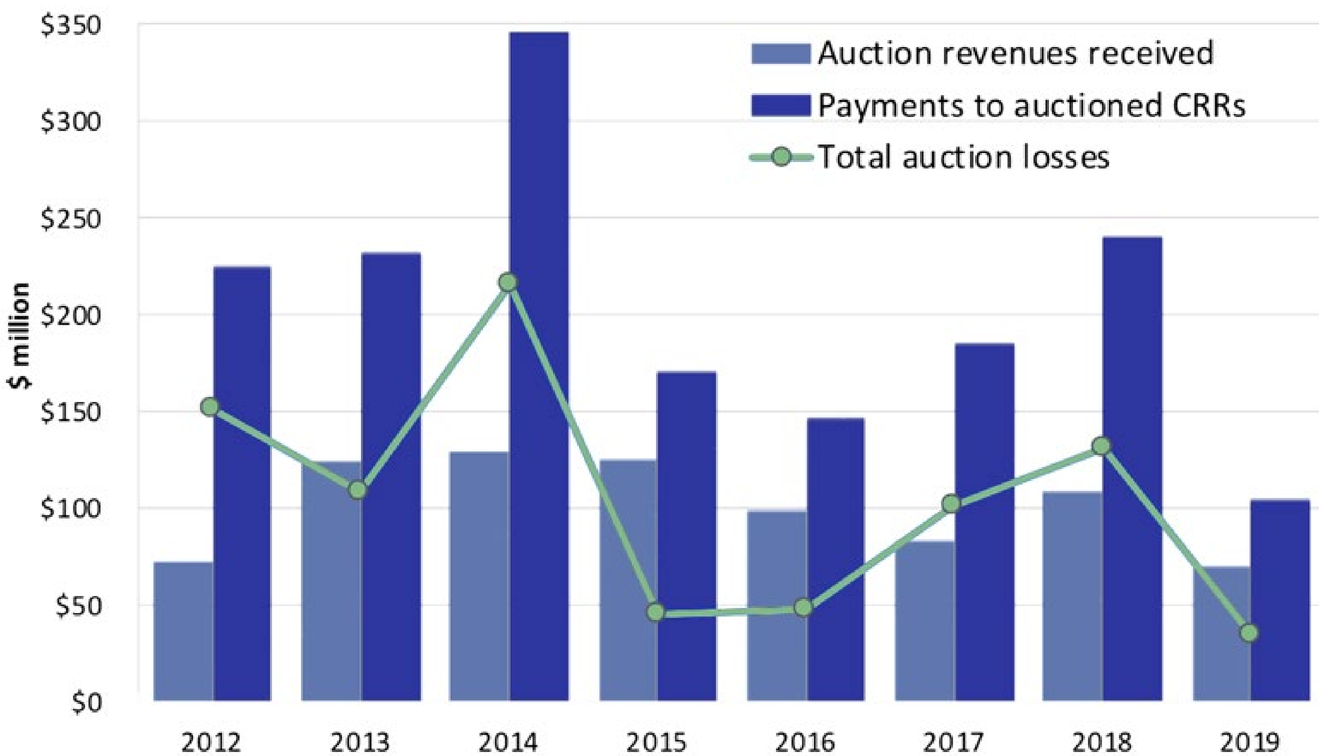
One rule change, called Track 1B, reduced payments to non-load-serving entities by $44 million, according to the DMM. The change limited payments from exceeding the congestion rent collected on the underlying constraints.

Another change, Track 1A, limited the kinds of CRRs that could be purchased at auction. It also appeared to have helped, though the changes couldn't be quantified, the department said.

FERC approved CAISO's rule changes in November 2018. (See *FERC OKs CAISO Plan to Deal with CRR Shortfalls*.)

The DMM said a third factor — lower congestion than in past years — played a major role too. Day-ahead congestion rent fell from $628 million in 2018 to $355 million in 2019, a 43% reduction.

"Thus, while losses dropped from $131 million to $32 million in 2019," the Monitor said, "a significant portion of this decrease can be attributed to the drop in overall congestion." ■



Auction revenues compared to payments to auctioned congestion revenue rights (2012-2019) | *CAISO*

CAISO/West News

FERC Approves NorthernGrid Merger

Protests Dismissed in Effort to Form New Western Tx Planning Region

By Hudson Sangree

FERC last week gave its blessing to the merger of Columbia Grid and Northern Tier Transmission Group to form NorthernGrid, a vast transmission planning region stretching across eight Western states (*ER20-882*, *et al.*).

The commission approved the latest revisions to the transmission tariffs filed by NorthernGrid's seven members: PacifiCorp, NorthWestern Energy, Avista, Puget Sound Energy, Idaho Power, MATL and Portland General Electric.

All the "filing parties' proposed tariff revisions are hereby accepted, effective April 1, 2020," FERC wrote.

In late December, FERC had sent the latest round of proposed tariff changes back to the parties, agreeing with independent transmission developer LS Power that the utilities failed to meet Order 1000's requirement to show the new transmission planning region would do better than the status quo. (See *FERC: NorthernGrid Merger Needs More Work*.)

FERC also said more information was needed to show the tariff revisions complied with Order 1000's principles of openness and coordination in transmission planning.

A major sticking point raised by LS Power was that the tariff changes, as drafted, would have required developers to submit proposed projects before the regional planning process identified transmission needs.

FERC agreed. "We find that this structure deprives developers and stakeholders of a sufficient opportunity to propose solutions in response to needs identified through the regional transmission planning process," the commission wrote, rejecting the proposal without prejudice and inviting the parties to refile after correcting deficiencies.

The parties filed their proposed revisions to their respective Open Access Transmission Tariffs on Jan. 28.

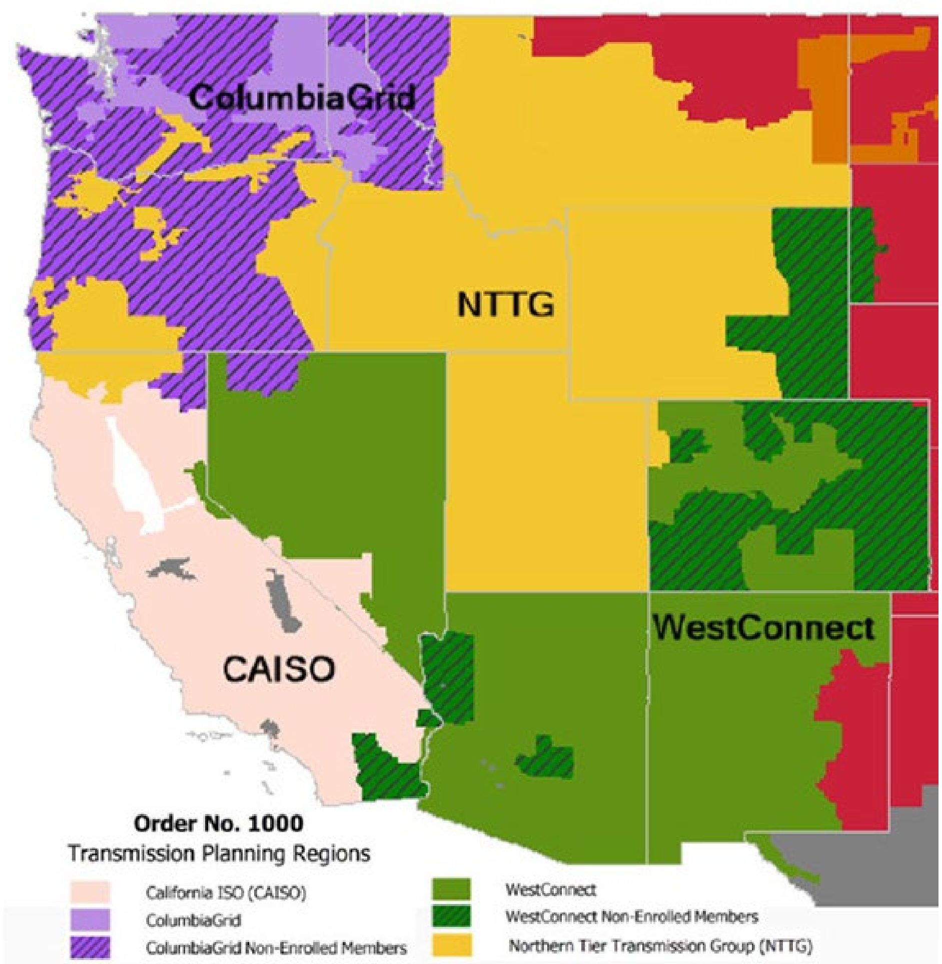
Among the changes, the parties "added a new 60-day window after posting [a regional transmission needs] draft study scope for stakeholders to submit additional data," FERC said. The change "provides a meaningful opportunity for transmission developers to submit project proposals after enrolled party needs have been identified."

LS Power again protested, saying the 60-day window failed to address the concerns it raised, and with which FERC agreed, before.

FERC rejected the argument, saying developers would have opportunities to propose projects in accord with Order 1000.

"We … find that the proposed regional transmission planning process complies with Order No. 1000's requirement to conduct a regional analysis to identify whether there are more efficient or cost-effective transmission solutions to regional transmission needs," FERC wrote.

That includes "an affirmative obligation to analyze whether such transmission solutions exist regardless of whether potential transmission solutions have been proposed by transmission developers or stakeholders," it said. ■



The proposed NorthernGrid regional planning organization would consolidate the areas covered by ColumbiaGrid and Northern Tier Transmission Group. | *ColumbiaGrid*

Puget Sound Energy, which operates the Wild Horse wind project in Washington State, is one of seven members seeking to form the NorthernGrid transmission planning region. | *PSE*

ERCOT News

Bivens Steps in as New Director of ERCOT Monitor

By Tom Kleckner

Former ERCOT staffer Carrie Bivens on Monday began her new role as director of the grid operator's Independent Market Monitor.

Bivens has spent nearly 14 years with ERCOT, most recently as director of wholesale operations. She oversaw the Texas grid operator's day-ahead market and congestion revenue rights auctions, as well as integration of load resources, distributed generation and emergency response service. As a subject matter expert in ERCOT's stakeholder process, Bivens has made frequent appearances in recent years before both its Board of Directors and the Texas Public Utility Commission.

Virginia-based Potomac Economics has provided ERCOT's market monitoring services since 2005 and was recently awarded another stint by the PUC, which has jurisdictional authority over the grid operator. Potomac also serves as the IMM for ISO-NE, MISO and NYISO.

Potomac interviewed the candidates and made the final selection. The PUC was given an opportunity to approve or reject the hire.

"I'm grateful to the PUC and to Potomac Economics for the trust bestowed upon me in this vital era in ERCOT as major initiatives such as real-time co-optimization of energy and ancillary services get underway," Bivens told *RTO Insider*.

As the IMM's director, Bivens will collaborate with the PUC to detect and prevent market manipulation and identify potential design improvements for the ERCOT wholesale market. She said her initial focus will be ensuring a "timely and comprehensive" State of the Market report for 2019. The report traditionally comes out in May or June.

Bivens replaces Beth Garza, who announced her departure as the IMM's executive director in December. (See *Garza Steps Down as Head of ERCOT IMM*.)

Steve Reedy, who served as the IMM's acting director following Garza's departure, will return to his role as assistant director.

In a statement emailed to *RTO Insider*, ERCOT said, "Carrie Bivens' skills as a manager and communicator are only exceeded by her intelligence and wit. The PUC could not have made a better choice, and ERCOT will miss her."


Carrie Bivens, ERCOT's new IMM director | *ERCOT*

Before coming to ERCOT, Bivens worked at FERC evaluating market-based rate filings and conducting market power analyses. She is a native Texan and a graduate from her hometown University of Houston. ■

ERCOT Technical Advisory Committee Briefs

Texas Grid's Weekly Energy Usage Down 2% in March

In its first report since the COVID-19 coronavirus pandemic forced most Texans to stay at home, ERCOT said last week it has seen a weekly 2% reduction in energy usage.

ERCOT Senior Director of System Planning Warren Lasher said during the Technical Advisory Committee's webinar Thursday that the grid operator has seen little change to its daily afternoon peaks. However, load has been off as much as 10% from 6 to 10 a.m., according to the grid operator's analysis.

Lasher cautioned that ERCOT is hampered by a delay in obtaining customer-specific data and has "limited operational" data to work with. He cautioned that spring break has also had some effect "on what we see."

Staff developed their analysis by taking a load forecast from January used for daily operational forecasts and added actual weather conditions to create a backcast model. The data Lasher referred to came from the week beginning March 22.

"Much of the variability in customer demand is driven by weather variability," Lasher said. Texas saw unseasonably high temperatures during March, with temperatures reaching the low 90s in some parts of the state.

Lasher promised to share a more granular look at the data in the near future and regular updates with the TAC.

Staff Following Pandemic Plan

Meanwhile, ERCOT continues its efforts to minimize the effects of the pandemic on operations.

Kristi Hobbs, who is responsible for ERCOT's enterprise risk management, said staff are following the grid operator's *pandemic plan*. Most have been working from home since March 18 — "We've been able to maintain a lot of productivity," Hobbs said — while operators have been alternating shifts between both control rooms. That allows for deep cleaning of the control rooms between shifts.

ERCOT has yet to report a positive test for the virus. Hobbs said a contractor is on call should a workspace need to be disinfected following a positive COVID-19 test.

"Our goal is to ensure we protect our employees and ensure ERCOT can maintain the key business functions you expect from us," Hobbs told the committee.

Staff have also drafted a document for qualified scheduling entities (QSEs) that describes how to set up remote control rooms and the importance of redundancy. The draft was to be finalized Friday and then posted publicly after a conference call to be scheduled with the QSEs.

Credit Becoming an Issue in ERCOT's Market

Reliant Energy Retail Services' Bill Barnes, who chairs the *Market Credit Working Group*, warned that there may not be enough collateral in the

ERCOT News

Bill Barnes, Reliant Energy Retail Services | © RTO Insider

market to keep some retail electric providers (REPs) from defaulting on their credit.

"We've done a good job to assess market-pricing risk. This event we're facing is not a market-pricing risk," Barnes said. "We have to prepare for an event where you'll see some REPs default. The concern is the collateral level that is held. The collateral ERCOT is holding may not be enough."

Barnes said his group is taking a hard look at all the parameters related to market participants' short payments, including: the timing of when ERCOT can recover short-paid funds (currently six months); the $2.5 million cap on the amount that ERCOT can recover in each default uplift invoice; and the time between when ERCOT issues default uplift invoices (30 days).

The working group, which evaluates credit-risk mitigation and the effect of protocol or market design changes on credit, will discuss a Nodal Protocol revision request (NPRR) addressing a quicker recovery of short-pay amounts during its scheduled April 15 meeting.

"The impact of COVID-19 on retail markets is something that was not contemplated in the ERCOT credit rules. This could be a long, drawn-out process," Barnes said. "Everything is being looked at to see if there's a better way to recover amounts quicker."

Real-time Co-optimization's Cost: up to $55M

Real-time co-optimization's (RTC) price tag has grown to $50 million to $55 million with an estimated timeline of up to four-and-a-half years, according to an *impact analysis* following the development of principles, or boundaries, that will guide ERCOT's implementation of the market tool.

ERCOT had originally projected it would cost at least $40 million to add RTC to its energy-only market. RTC procures both energy and ancillary services every five minutes to find the most cost-effective solution for both requirements.

ERCOT's Matt Mereness, chair of the Real-Time Co-optimization Task Force, told the TAC that the group has identified about 190 different protocol sections that will need to be modified or written. The task force has produced a 44-page *document* encapsulating the nine months of work on the key principles, which were approved by the grid operator's Board of Directors in February. (See "Real-Time Co-optimization Team Finalizes Scope," *ERCOT Board of Directors Briefs: Feb. 11, 2020*.)

"2020 is the year to get the protocols done so we can work on the business requirements," Mereness said. "The key is to be wrapped up by the middle of 2021 so we can develop the systems."

Mereness promised more details during the task force's April 8 meeting, when the group will take its first dive into the protocol section.

The RTC project will touch at least a dozen systems. The task force expects ERCOT's Market Management System to be the most affected system.

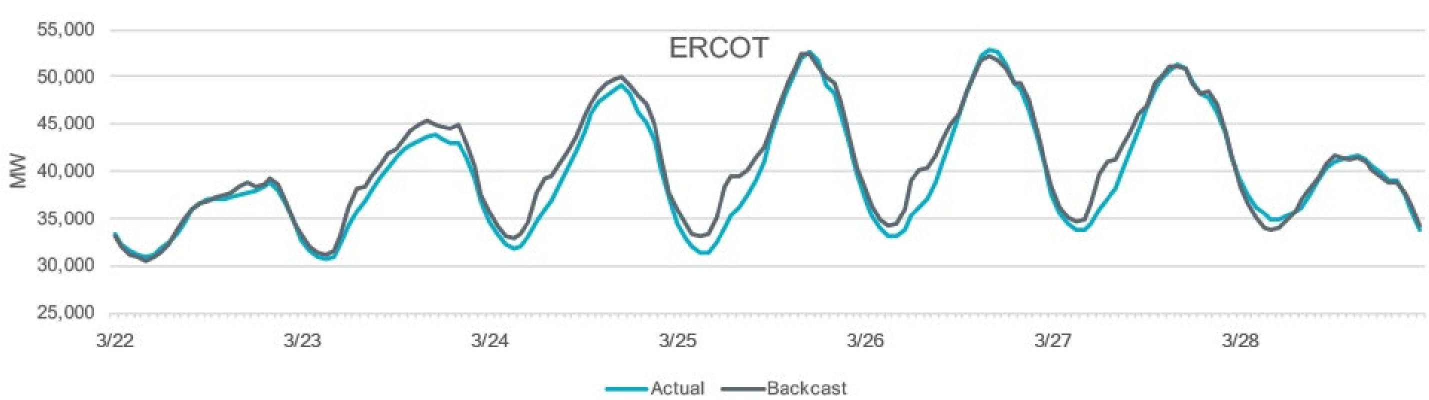
Mereness said there is little slack in the project's timeline and that the task force plans to avoid mistakes similar to those of the nodal market project, which was beset by ballooning costs and delays as teams added unnecessary elements to the systems.

"If there's something wrong or missing, we'll get in there and fix it," he said. "But if it's additional functionality or something nice to have, that's where we would challenge any and all changes that will affect the schedule and the budget."

TAC Endorses 4 More Energy Storage Concepts

The committee endorsed four additional key topic/concepts (KTCs) brought forth by the Battery Energy Storage Task Force, which has been charged with integrating battery energy storage resources (ESRs) into ERCOT:

- *KTC 11*: Establishes how DC-coupled resources register and participate in the combo-model and single-model "era" (before single-model ESR implementation). Single-model will be implemented in 2024 when RTC goes live.
- *KTC 12*: Recommends that the existing market rules and practices are sufficient for co-located AC-connected ESRs for registration, participation model, forecasting, performance, mitigation treatment in security-constrained economic dispatch, wholesale storage load treatment and data requirements from QSEs.
- *KTC 13*: Defines a self-limiting generation site as a combination of one or more resources combined with an energy storage system behind a single point of interconnection, where the generation and energy storage system's total capacity is greater than either the interconnection agreement's maximum power export (Pmax) rating or the inverter rating. Similar consideration may also apply to maximum power withdrawal (Pmin). QSEs should manage a self-limiting generation site's performance to not exceed the established Pmax or withdraw more than the established Pmin from the grid.



ERCOT's load patterns as the coronavirus takes hold | *ERCOT*

ERCOT News

KTC 15: Describes the proxy process for both ESR models.

The BESTF has developed an issue-tracking spreadsheet to monitor discussion points and its progress. Chair Kenneth Ragsdale, with ERCOT, said the group is working through the NPRRs that will be submitted to the Protocol Revision Subcommittee.

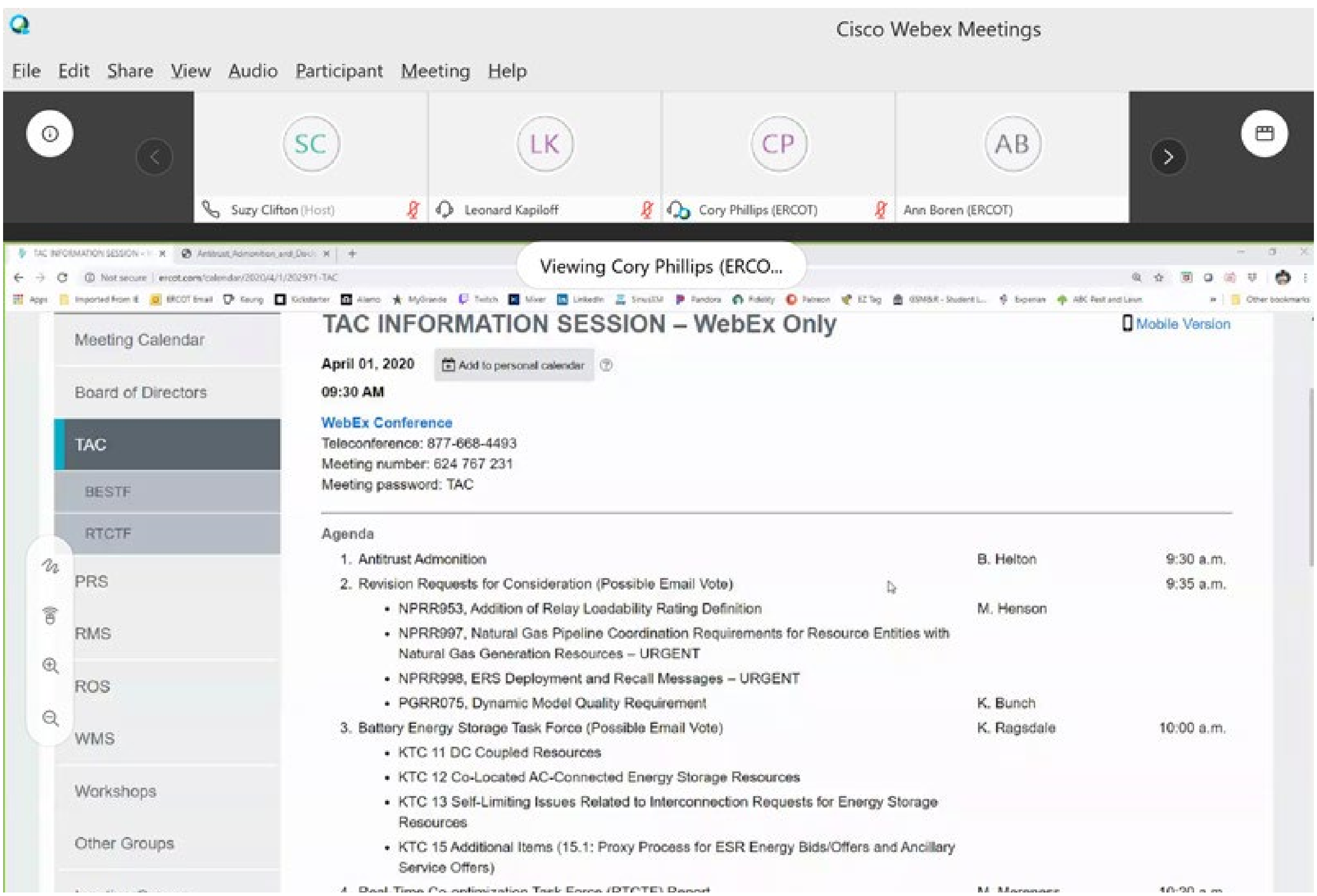
TAC Approves 4 Change Requests

The committee approved three NPRRs and a single change to the Planning Guide (PGRR) in a nearly unanimous email vote that concluded Friday. The lone dissent was independent power marketer Morgan Stanley's opposing vote against NPRR998.

- 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 QSE has made a written effort to communicate with the operator of each gas pipeline that is 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 a message to the Market Information System's public area every time emergency response service is deployed or recalled.
- 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.

ERCOT's legal staff have approved the use of electronic votes by stakeholders during the pandemic emergency, asking only that such meetings use communications equipment that allows attendees to hear each other. If necessary, votes can be validated after the meeting, staff said. ■

— Tom Kleckner



The TAC's April 1 meeting gets underway via the web.

ISO-NE News

FERC Reaffirms ISO-NE Winter Program Cost

By Rich Heidorn Jr.

FERC on Wednesday reaffirmed its conclusion that bidding results in ISO-NE's 2013/14 Winter Reliability Program were just and reasonable despite the fact that the largest participants may have had market power (*ER13-2266-004*).

ISO-NE's program offered compensation to demand response and generators able to burn oil to prevent New England from falling short of power in the winter because of the retirement of coal-fired units and tight natural gas supplies.

Wednesday's order was prompted by a D.C. Circuit Court of Appeals ruling in December 2015 that said the commission had failed to justify its approval of the auction results. Although ISO-NE estimated the program would cost no more than $43 million for up to 2.4 million MWh of energy, the RTO filed for approval of bids totaling 1.95 million MWh at a cost of $75 million.

The court said that in approving the auction results, FERC failed to address how much of the program's cost was attributable to profit and risk mark-up or to explain the economic forces that it believed restrained participants from submitting excessive bids.

The court was acting on an appeal by TransCanada Power Marketing, which contended ISO-NE's pay-as-bid auction resulted in excessive costs because resources were incented to raise their bid prices knowing they would probably be accepted.

In response to the D.C. Circuit's remand, FERC directed ISO-NE to query bidders on the process they used to formulate their offers. It also ordered the RTO and its Independent Market Monitor to opine on the reasonableness of the bids based on that information. (See *ISO-NE Ordered to Justify Cost of Winter Reliability Program*.)

The IMM found that each participant had market power because there was insufficient supply to meet the RTO's 2.4 million MWh procurement target and that the program did not include a mechanism for mitigating their leverage. It said market participants were aware of their market power because the first auction failed to attract sufficient supply to meet the target.

About 70% of the supply offered into the auction came from only four participants, a concentration that the IMM said allowed them to submit bids above a competitive level.

After the remand by the D.C. Circuit, the IMM calculated that the supply curve would intersect with the assumed procurement level of 1.95 million MWh — the amount procured in the second auction — at a marginal cost of $15.08/MWh-month.

The Monitor boosted that price to $18.85/MWh-month — a 25% risk premium reflecting participants' limited information regarding the auction's supply and demand curves and uncertainties over how the RTO would value resources in what was the first year of the program.

The IMM estimated the auction resulted in potential cost overages of $6.6 million, compared to what the program would have cost if all bids were at or below $18.85/MWh-month. The IMM concluded that 75% of the supply offered was competitive, but the remaining 25% "included sufficiently high markups to raise concerns that participants submitting bids for this supply may have exercised market power."

"Market design issues, lack of information, uncertainty and measurement accuracy issues … prevent us from concluding, with certainty, the extent to which participants exercised market power or the impact it had on program cost," the Monitor said.

ISO-NE conducted a similar analysis but assumed a supply curve of 2.25 million MWh, which it said would result in a clearing price of $24.86/MWh-month, or $31.08/MWh-month including the 25% adder.

It concluded there was no evidence that market power was exercised because there were no bids above $31.08/MWh-month. Using $24.86/MWh-month, it estimated $1.72 million in potential cost overages.

"We find that although the IMM found that the auction was not structurally competitive, ISO-NE nevertheless demonstrated that the Winter Reliability Program prices were just and reasonable because there were factors that sufficiently restrained parties' ability to exercise market power," FERC said. "These factors included the facts that, ahead of the auction, participants lacked information about ISO-NE's chosen level of procurement, the costs and strategy of their competitors, and how ISO-NE would value the non-cost reliability factors that it would consider in addition to price when selecting bids."

FERC compared the $75 million cost of the program to ISO-NE's estimate in 2013 that the value of lost load "could reach into billions of dollars for a region the size of New England." The RTO had *cited* estimates of the costs of the 2003 Northeast blackout, which ranged from $4 billion to $10 billion ($2003).

For a "competitive benchmark," FERC looked at what costs would have been had the RTO used a single-price clearing auction — which incents bidding based on individual resource's marginal cost — rather than pay-as-bid, in which participants seek to bid just below their estimate of the clearing price.

If resources bid based on marginal costs, FERC said the auction would have cleared at $15.08/MWh-month for a total of $88 million — above the actual total of $75 million ($12.82/MWh-month).

TransCanada protested the auction results, saying that ISO-NE's "reliability need ... created an essentially inelastic vertical demand that suppliers were aware of."

FERC disagreed, saying that while the RTO said it would purchase "up to" 2.4 million MWh of winter reliability service, it ultimately purchased only 1.95 million MWh. "Contrary to TransCanada's view, structural market power alone (i.e., a structurally uncompetitive market) does not necessarily result in unjust and unreasonable rates," the commission said.

FERC also disputed the IMM's conclusion that the 70% market share held by the four largest participants — the result of a C4 concentration test — was evidence that the auction was uncompetitive.

The commission said its preferred concentration test, the Herfindahl-Hirschman Index (HHI) — which sums the squares of the market shares of each market participant — resulted in an HHI of 1,462, "indicating a moderately concentrated, but not a highly concentrated, market."

Even assuming there was structural market power, "there is no conclusive evidence that participants knew they had structural market power; therefore, participants would have bid competitively," FERC said. "This is particularly likely given that the Winter Reliability Program presented a new product market with no prior auctions, making it more difficult to determine which other oil-fired generators would choose to participate and then what quantity of service each would bid (to cover their respective costs and include profits sufficient to warrant their participation in the auction)." ■

ISO-NE News

Van Welie: ISO-NE Pandemic Transition Going 'Smoothly'

By Michael Kuser

ISO-NE CEO Gordon van Welie said that the RTO activated emergency operation procedures to counter the COVID-19 pandemic on March 12 and that "it's been really gratifying to see how smoothly the transition went."

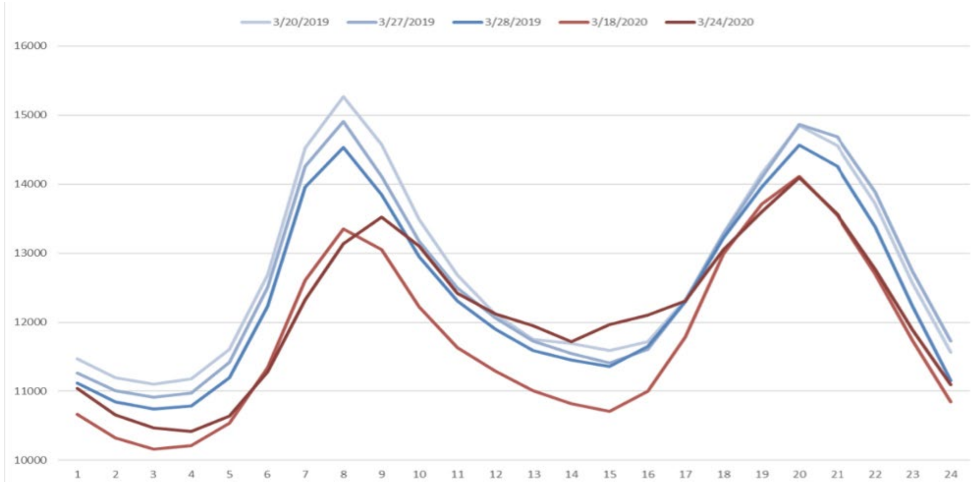
"We have all these contingency plans, emergency plans, and have experimented with half the workforce working from home, but we never had to implement them for real before now," van Welie told the New England Power Pool Participants Committee on Thursday.

The RTO has more than 95% of its workforce now working remotely, with remote deployment to continue through at least May 4, and is taking special care for the health of crews for the two control centers, ISO-NE COO Vamsi Chadalavada said.

"The industry has really come together in a very refreshing and collaborative way," he said. "I think folks have closed ranks; there's a lot of cooperation; and best practices are being shared in near real time. There are extensive communication protocols across the country and internationally."

The Electric Power Research Institute has been hosting sessions, and the RTO conducts its own conference calls with generators and every key link in the supply chain to ensure reliability, Chadalavada said.

Chadalavada *reported* overall March 2020 demand approximately 3 to 5% lower than in prior years, with load curves having changed shape with the pandemic outbreak from the second half of March as the New England states started to require people to stay home.



Comparison of a few similar days between 2019 and 2020 for midweek in the second half of March. 2020 load curves show as lower and delayed ramp in the morning; overnight loads are lower with closings of 24-hour operations. | *ISO-NE*

"The load curves that are now being established mimic snow days when people typically stay home and businesses are either shut down or otherwise operating at not full speed," he said. "We see that the morning ramp is delayed. What used to be a ramp around 7 a.m. is now extending to 8 a.m. or even 9 a.m."

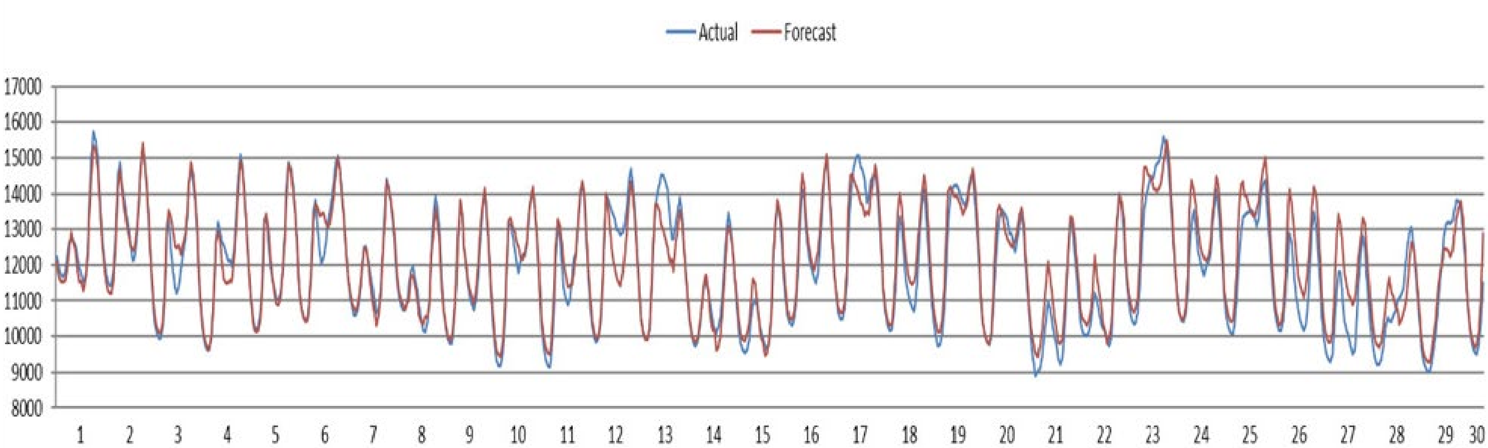
The situation presents a challenge to forecasting load, especially now, and the deviation from actual load has in the last few days been "north of 3%, so we're clearly not meeting our target 1.8% error, but our forecasters are vigilant and staying very close to system conditions," Chadalavada said.

The RTO is exploring the risk of underestimating loads after the pandemic-induced economic shutdown, he said.

With continued choppiness expected over the next week, "we are trying to train our models, but as you can assume, two weeks of training is almost insufficient for any model to upgrade its performance," Chadalavada said. "Coming out of it will be an even bigger challenge, so right now I see the algorithmic foundation as the biggest challenge for forecasting load."

In terms of settlement, the RTO has well established procedures, he said.

"If there are any delays in flow of data, and if we have to make adjustments to it because of any reason, I'm sure we will act quickly and work with all of you to do so," Chadalavada said. ■



Comparison of the unadjusted output of a single load forecast model to the actual New England load in March. Peaks and valleys are similar until around March 15, when the coronavirus began to hit the region. | *ISO-NE*

ISO-NE News

ISO-NE Sending 2 Energy Security Plans to FERC

Continued from page 1

(NESCOE) by a 61.7% sector-weighted vote, with unanimous support from the Transmission, Publicly Owned Entity and End User sectors and unanimous opposition from the Generators. ISO-NE's unamended proposal received only 39.6% support, with support from Generators, Suppliers and Alternative Resources and unanimous opposition from the other sectors.

ISO-NE said that although FERC has found that certain compliance filings are not covered by the "jump ball" provisions of the NEPOOL Participants Agreement, it "has committed nonetheless to include in its April 15 filing the same information it would include were the filing a jump ball."

The RTO said it will include a description of the NESCOE proposal "in detail sufficient to permit reasonable review by the commission, explain [ISO-NE's] reasons for not adopting the proposal and provide an explanation as to why [ISO-NE] believes its own proposal is superior to the proposal approved by the Participants Committee."

The result of more than a year of stakeholder meetings, the ESI proposal was prompted by FERC's July 2018 finding that ISO-NE's Tariff is not just and reasonable because the RTO lacks a way to address fuel security concerns that it said could result in reliability violations as soon as 2022. The Tariff currently allows cost-of-service agreements only to respond to local transmission security issues (*EL18-182, ER18-1509*). (See *FERC Denies ISO-NE Mystic Waiver, Orders Tariff Changes*.)

FERC last August granted the RTO an extension to file the plan by April 15.

In March, the RTO's unamended proposal failed in the NEPOOL Markets Committee with 42.4% in support, while a proposal including NESCOE's amendment to set the value of replacement energy reserves (RER) to zero for non-winter months — essentially eliminating it except for three months — only received 51.77% support. (See *NEPOOL Markets Committee Briefs: March 24, 2020*.)

Mathematics Exercise

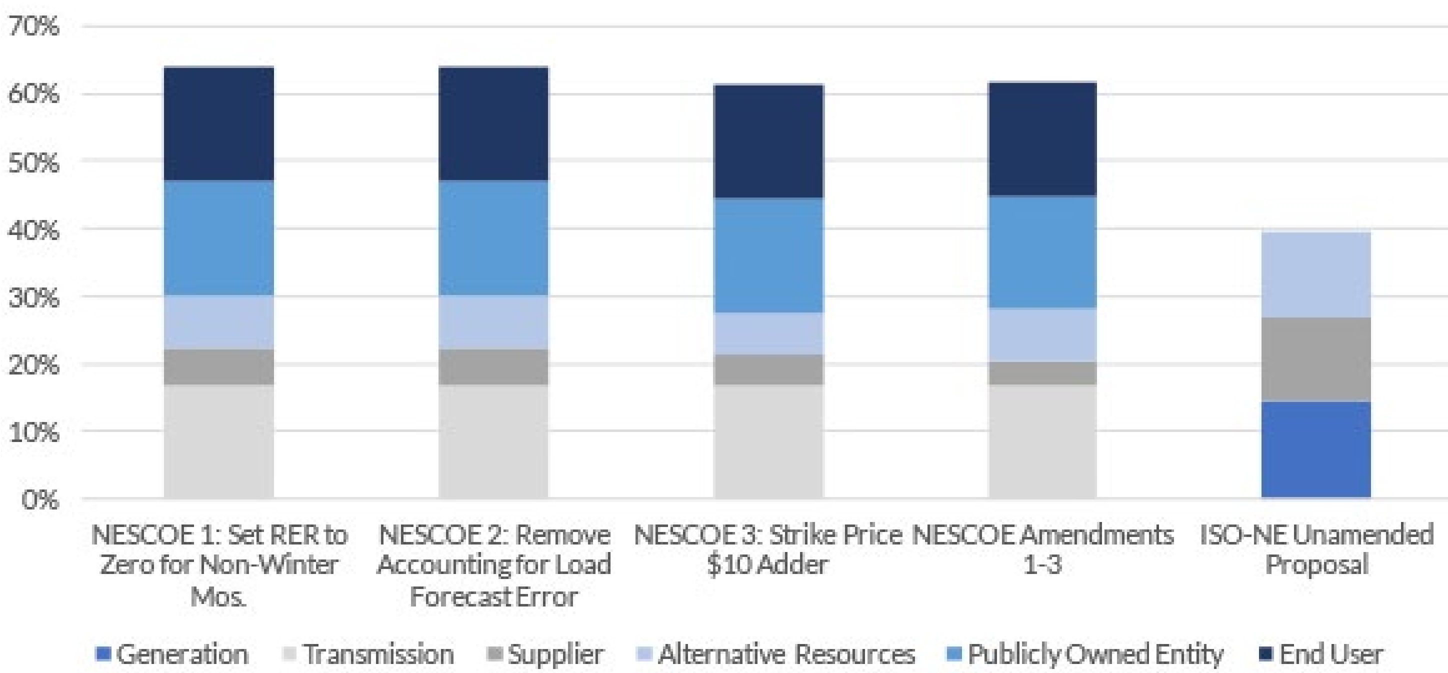
The PC approved three amendments proposed by NESCOE before approving the amended ESI package.

Jeff Bentz, NESCOE director of analysis, proposed the amendments "because the concerns we raised as early as April 2019 and even before haven't been addressed to our satisfaction, and we believe that puts consumers at great risk, especially during extended cold snaps.

"As we sit here today, the only commitment from ISO-NE is to consider increasing the quantities through a yet-to-be determined addition for load forecast error and to add even more consumer cost through some type of forward market concept that likely will increase costs and not add much additional reliability benefit," Bentz said. "NESCOE brings forward these three amendments to help bring the cost-versus-benefits inequities closer in balance."

The first amendment to set the RER value to zero for non-winter months passed with 63.76% in favor, as did the second NESCOE amendment, which was to remove the RTO's ability to adjust reserve levels to account for load forecast errors.

Massachusetts Assistant Attorney General Christina Belew said her office supported the first amendment "because we don't think the RER product is required under the [Northeast Power Coordinating Council] Directory 5. We think it has a tenuous link to fuel security, and it is disproportionately expensive." *Directory 5*



NEPOOL's Transmission, Publicly Owned and End User sectors unanimously backed three NESCOE amendments to ISO-NE's ESI proposal, and a fourth vote that combined all three amendments, while the Generation sector uniformly opposed all the changes. ISO-NE's unamended proposal had strong support from Generators, Suppliers and Alternative Resources but was unanimously rejected by the three other sectors. | *NEPOOL*

ISO-NE News

sets minimum requirements for "the amount, availability, distribution and activation of reserve in addition to those specified in applicable NERC standards."

[Note: Although NEPOOL rules prohibit quoting speakers at meetings, those quoted in this article amplified their remarks afterward to clarify their presentations.]

"This whole effort was built around the Analysis Group's assessment of a way to pay for a very minor, 10-day LNG contract, so it was all about 10 days of LNG," said Brett Kruse of Calpine, who voted against all the amendments but supported the RTO's proposal. "For the record, none of the folks that voted against in the Markets Committee, nor any of the folks who've spoken out against it today, have offered an alternative to secure winter fuel security for New England.

"If you look at this as a mathematics exercise, the numbers don't add up without the entire ISO New England package, and even then, it's marginal," he said. "Second, we'll make prudent business decisions year over year, and if that means going into a winter where we don't think we're going to be able to recoup the costs of an LNG contract we probably won't buy it."

NESCOE's third amendment, to include a $10/MWh adder to the strike price in all hours, passed with 61.27% in favor. NESCOE said it would reduce the cost and risk of the energy call option for providers without materially affecting resources' incentives under the program.

Down, not Out

Bentz said NESCOE's objections to the unamended ESI proposal fell into two categories.

"First of all, the ISO's proposal is an unpredictable, year-round call option approach," Bentz said. "We think it exceeds the scope of the FERC's order in 2018, and instead of just addressing winter fuel security, the ISO creates this novel, untested and potentially very expensive program for pricing reserves in the day-ahead market.

"Secondly, ISO-NE's proposal is going to produce an unjust and unreasonable rate," Bentz continued. "The ISO's approach is highly vulnerable to producing uncompetitive outcomes due to the inability to effectively mitigate market power. It procures substantially more reserves than the system needs, and at an excessive cost to customers.

"The ESI design is not good value for the money, and collectively, the six New England states are not in favor of this design as being presented here today," Bentz said.

ISO-NE COO Vamsi Chadalavada offered the grid operator's perspective on ESI.

"In our view, we are working to balance energy security concerns, not just for the immediate time frame, but for the longer term, and think a more complete design will accomplish that," Chadalavada said. "We are mindful and sensitive to consumer costs, and it's certainly been one of the considerations as we built the risk-responsive design."

The regional electric power system is evolving fast and the RTO has sometimes been reactive, he said.

"This design positions us better as New Englanders because it allows us to be more proactive in terms of the uncertainties that we face," Chadalavada said.

OKs Early EIP Sunset

The committee also approved Tariff *revisions* to sunset the RTO's interim Inventoried Energy Program (IEP) after capacity commitment period 2023/24, one year earlier than the end date in the current Tariff. The early sunset would be conditioned on FERC's approval of the ESI proposal for implementation no later than June 1, 2024.

FERC in February rejected a request by ISO-NE and NEPOOL to roll back the sunset date for a Tariff provision that allows the RTO to retain a resource for fuel security reasons. The RTO said it plans to refile the Tariff revision when it files its ESI proposal. (See *FERC Rejects ISO-NE Fuel Security Sunset Rollback*.)

Other Actions

The PC also approved as part of its consent agenda revisions to Market Rule 1 relating to energy efficiency resources' capacity supply obligations during scarcity conditions, as proposed by NESCOE and recommended by the MC in March.

The committee also unanimously approved revisions to Market Rule 1 to address FERC's March 10 order rejecting provisions governing how ISO-NE's Internal Market Monitor calculates the economic life of resources that want to retire or permanently leave the capacity market. The provisions were intended to correct calculations that ISO-NE said overstated the true economics of some resources and could result in improperly high delist bids. But the commission said the rules' effective date would upset market participants' "settled expectations" after the Forward Capacity Auction 13 qualification process for delist bids had begun (ER18-1770-002). (See *FERC Reverses Ruling on ISO-NE 'Economic Life' Rules*.)

The proposal asks FERC to make the changes apply prospectively beginning with FCA 16. ■

MISO Contemplates 'DER Balance Problem'

By Amanda Durish Cook

MISO is stepping up efforts to understand how its markets will function with the possible participation of heavy concentrations of distributed energy resources.

The RTO is researching how to manage DER aggregators in its market, DER Program Director Kristin Swenson said during a joint workshop between MISO and the Organization of MISO States (OMS) on March 31.

The workshop was held over telephone — rather than in person — because of the COVID-19 pandemic.

"I'm leading a virtual MISO stakeholder workshop upstairs while my wife leads a virtual yoga class downstairs. A lot of 'virtuality' these days," MISO Managing Assistant General Counsel Michael Kessler remarked as he began his presentation.

Swenson said the MISO market platform's computational abilities cannot handle the addition of several thousand small, distributed resources. She also noted that broad DER aggregation across multiple nodes is difficult to manage from an operations standpoint. The RTO may be unable to handle some issues if it doesn't precisely know the physical location of some aggregated resources, she said.

"You may not be able to solve the transmission or reliability issues without visibility from an aggregator," Swensen explained. "That's what we call the DER balance problem."

MISO last held a DER workshop in February, in which it focused on transmission planning challenges as the distribution system takes on more generating resources. (See *MISO Mapping Out DER Challenges, Benefits*.)

Energy storage may assist in the balancing act. FERC Order 841 mandated RTOs facilitate participation for storage resources over 100 kW located on distribution systems. In response, MISO created a contract in its Tariff to coordinate with distribution utilities that host storage resources.

But a legal challenge to Order 841 is currently pending before the D.C. Circuit Court of Appeals. Opponents of the order, which include the National Association of Regulatory Utility Commissioners and traditional utilities, are suing to block FERC's ability to mandate DER participation in wholesale markets and seeking an opt-out mechanism for states.

Hoosier Energy Power Network Solar Power Plant in Bloomington, Ind. | *Inovateus-Solar*

"We're still waiting to see what the states' authority will be and what FERC's jurisdiction will be over storage resources located on the distribution system participating in wholesale markets," Kessler said.

In addition, FERC's 2016 Notice of Proposed Rulemaking on the participation of DER aggregation in wholesale markets is still outstanding.

Working Through the Tension

Swenson said MISO's work with OMS on DERs began in preparation for a federal rulemaking on DER participation.

OMS Executive Director Marcus Hawkins said the increasingly blurred lines between state and federal jurisdiction "has created tension." He said a DER participation model must respect the "primarily vertically integrated nature of the MISO footprint."

"Whatever the eventual market model is, it should reflect that fact," Hawkins said.

Hawkins said a significant number of aggregators selling at the wholesale level could disrupt state-jurisdictional resource adequacy planning.

"There's just a lot of coordination required when a DER wants to participate in the wholesale market," Hawkins said, adding that OMS wants to avoid double-counting when a resource on the distribution system participates at both the wholesale and retail levels. However, he said MISO, utilities and states should not all rush to invest in technology that's ultimately "redundant" in order to gain visibility into DER operations.

"We've been fighting against wasteful technology to do that," Hawkins said.

Swenson said MISO will survey members in mid-April on how they currently communicate with DERs, what investments they have made to improve communications and what approaches they would recommended.

"We're trying to get a good impression of where folks are in communicating with DERs as MISO prepares to communicate with more resources. Where should MISO be focusing?" Swenson said.

Swenson stressed that the new survey is separate from the annual OMS survey on DER totals in MISO.

Independent Market Monitor staffer Michael Chiasson said the monitoring of DERs isn't a concern for now. DERs and demand response "typically lack the size and concentration needed to have significant market power," he said.

However, Chiasson noted, DERs could help lessen the market power wielded by large, traditional generators in load pockets constrained by transmission limitations.

"It's a good structural thing to have more market participants," Chiasson said.

Chiasson said if the Monitor eventually discovers that DERs could exercise market power, it could propose to FERC under Federal Power Act Section 205 to adjust the application of market mitigation.

"A lot of market rules evolved that way," Chiasson said. ■

MISO Deepens Insights into Pandemic Impact

By Amanda Durish Cook

MISO is gradually improving its ability to forecast the more sedate load profiles that have emerged in the face of widespread community measures to halt the COVID-19 pandemic, stakeholders learned Thursday.

Ron Arness, MISO | *© RTO Insider*

The RTO is experiencing lower loads that no longer follow a sharp uptick in demand in the morning or evening, Director of Central Region Operations Ron Arness told stakeholders during a Reliability Subcommittee conference call Thursday.

"We have seen significant shifts in the morning and evening peaks. For instance, the morning peak has shifted from the usual 8 a.m. and 9 a.m. to about 11 a.m. or noon and then it's not dropping off — and it's staying steady until it dissipates in the evening," Arness said. "It's a more gradual increase. We're seeing more steady peaks across the day, [and] we've not seen that evening bump-up in peak."

MISO officials initially compared evolving load profiles to weekend usage patterns, but RTO staff now find that a slew of business closures have contributed to lower load than even typical weekend days. (See *MISO Loads Down as Region Faces COVID-19 Threat*.)

"There have been a lot more closures going on, in restaurants as well as industry. So, it's not an exact weekend profile, but it's close," Arness said. "It's down slightly — it's still going down."

MISO has experienced load forecasting errors for both on- and off-peak periods, Arness said, but he added that forecasters since March 23 have begun more aggressively predicting load shapes based on recent demand tracking and are each day manually inserting them into existing models.

Arness said that while MISO's load was significantly down in March compared with a year earlier, most of the decline can be attributed to higher temperatures. Peak loads decreased 18% from 2019 and were down 13% from the March five-year average. March's peak usually breaks just above 90 GW, but last month topped out at 79 GW.

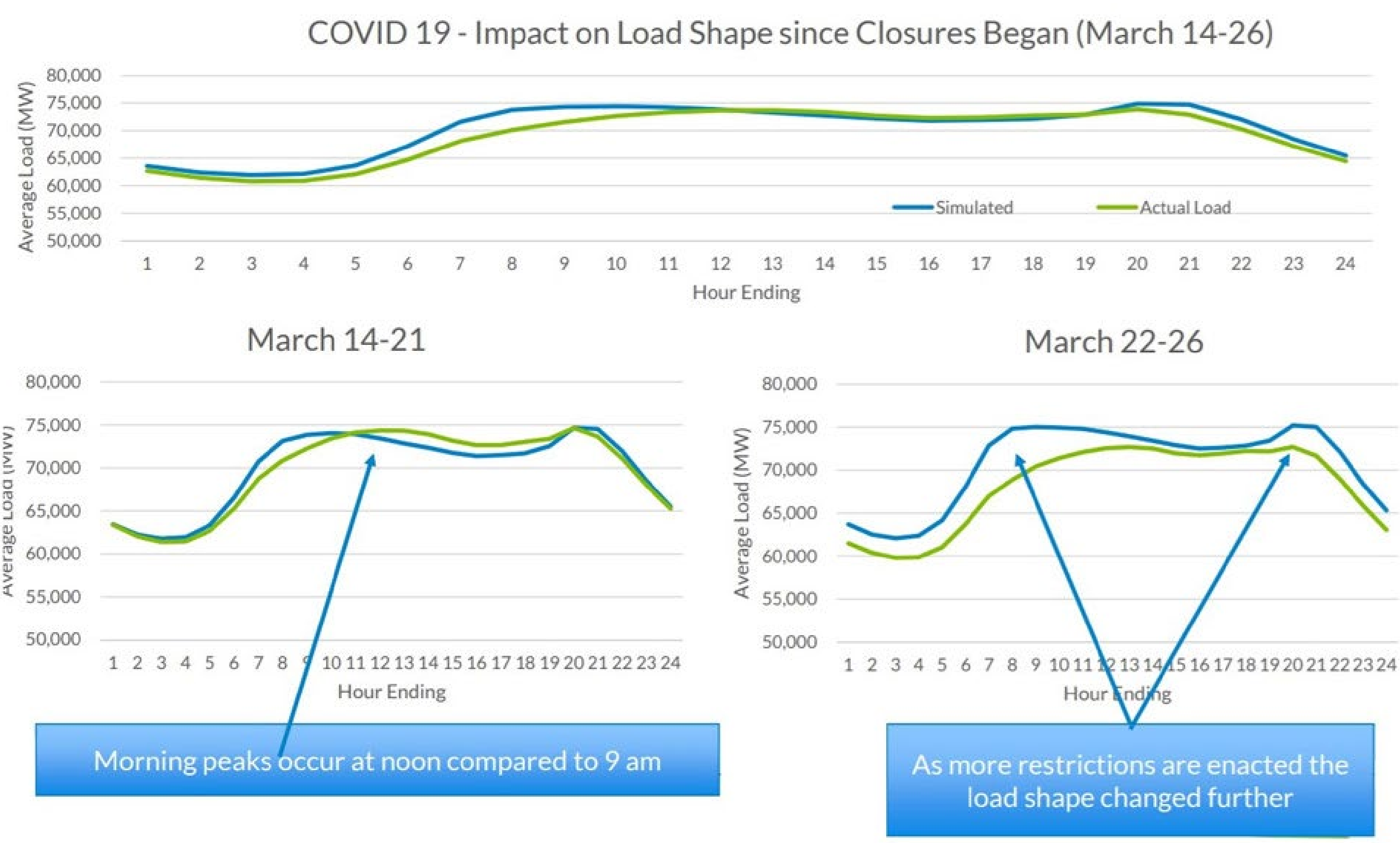
"We believe most of that is due to the temperature," Arness said.

MISO said the few weeks of load forecast errors have not impacted reliable operations.

"These are unprecedented times, and we're starting to hone [in on] it and get a little better," Arness said.

Varying Emergency Responses in Footprint

Arness also said the sheer size of MISO's footprint means that its uncharted load forecasting doesn't fit neatly into a new model. He pointed out that states in MISO South have not yet clamped down on gatherings or population



COVID-19 early impacts on MISO load shapes | *MISO*

MISO News

movement in the stricter ways that Michigan or Illinois have through industry shutdowns and travel restrictions.

"That's why we're still seeing some continued changes in our numbers," he said.

The Energy and Policy Institute *reports* that 22 state commissions — including seven in the MISO footprint — have so far ordered utilities to suspend disconnections as the pandemic wears on.

Wisconsin in particular has moved proactively to gauge the economic impact of stay-at-home measures on ratepayers and utilities. The state's Public Service Commission has *opened* two new dockets: one to ensure customers can continue to access service, and the other to investigate the costs utilities are incurring under the public health emergency orders. Gov. Tony Evers *suspended* some of the PSC's administrative rules so public utilities can waive late fees, halt disconnections, connect residents more quickly and without cash deposits, and offer deferred payment agreements for commercial, farm and industrial customers in addition to residential customers. Utilities are beginning to warn of deferred maintenance and financial impacts. (See *AEP Warns of 'Adverse' Effects from Coronavirus*.)

Northern Indiana Public Service Co.'s Bill SeDoris said his company is checking temperatures of employees before they're allowed into company offices. He also said NIPSCO has brought in trailers to park on-site as temporary offices for customer service representatives.

"We're giving them more space so they're not on top of each other," SeDoris said.

What Lies Ahead

MISO headed into this month with the manual, day-by-day load forecasting in place.

"April is a time when we have big variety in temperatures. But generally, the load is lower," Arness said.

MISO also plans to hold a summer readiness workshop April 28. It's not yet clear how the pandemic will affect summer operations.

Arness emphasized that MISO needs ample warning from generators that foresee a need for conservative operations or outage rescheduling. He said MISO had observed an uptick in outage deferments over the past week. The RTO last month noted increased deferment of maintenance outages as utility work crews were scaled back as social distancing took hold.

"The plea here — I can't say this often enough — is that you document the request. We're really imploring the generation owners and operators to please keep MISO updated in terms of your plans. Please document them in writing," Arness urged market participants, adding that the RTO needs all relevant information on changes in outage plans to navigate outage scheduling.

Jim Dauphinais, an attorney with the Coalition of Midwest Transmission Customers, asked how MISO was dealing with load-modifying resources (LMRs) that aren't available with no personnel on-hand to lower load. He also wondered if some LMRs could even be considered deployed because they're already shuttered because of shelter-in-place orders.

"There might be no demand reduction that would come from a MISO call since load is already reduced," Dauphinais said, adding that the RTO should examine how LMRs in limbo could impact an emergency declaration.

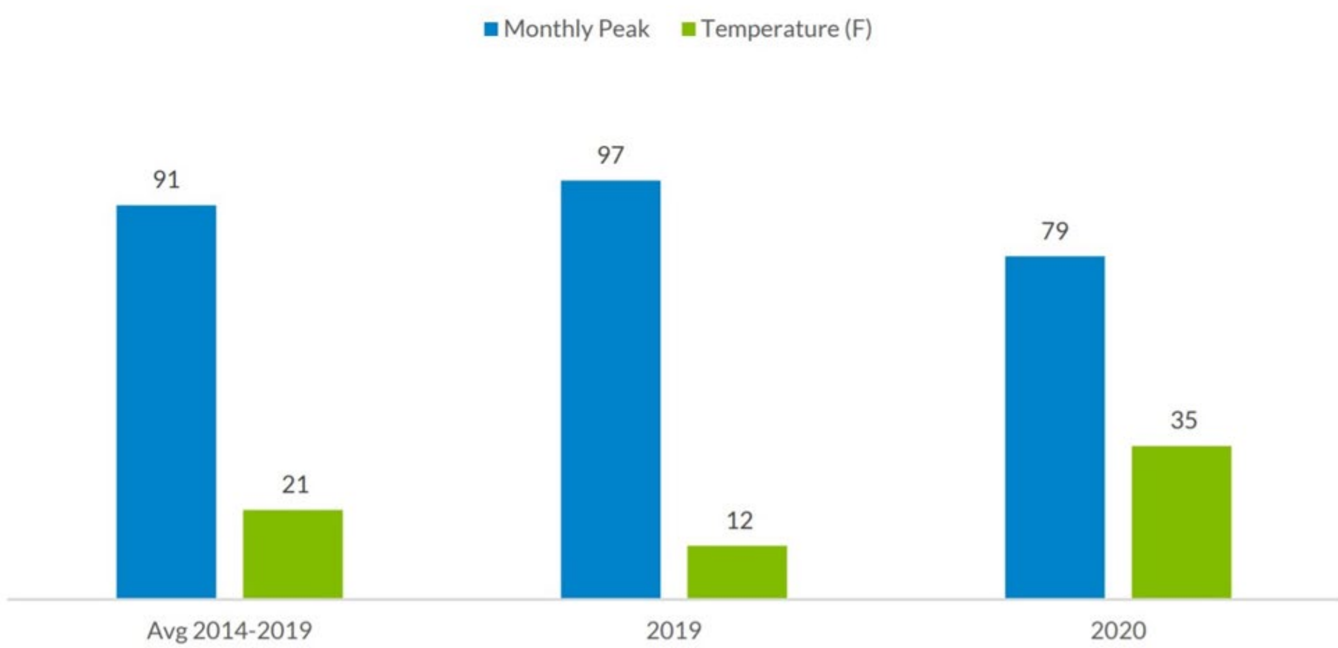
Rob Benbow, MISO's executive director of energy operations, asked all LMR owners to update their availability in the MISO Communication System. He said MISO would examine how LMRs that are temporarily unavailable or considered already deployed could impact resource adequacy.

Customized Energy Solutions' Ted Kuhn asked if MISO is contemplating how it will best manage a return to normalcy once social distancing mandates are lifted and load picks up.

"There's a good argument that load is going to return, but the question is will it return to those historical levels that we experienced a year ago. That's a good question, and we're studying it," Arness said.

MISO will hold another Reliability Subcommittee meeting April 29, in which COVID-19 impacts will again be discussed.

"Be safe, take care of yourselves and your families," SeDoris said before ending the call. ■



MISO March load comparison (GW) | *MISO*

MISO News

FERC Approves Prescott-SWEPCO Settlement

By Amanda Durish Cook

FERC on Wednesday resolved a dispute over overlapping congestion charges on the MISO-SPP seam when it accepted a settlement between Southwestern Electric Power Co. (SWEPCO) and the city of Prescott, Ark.

The settlement outlines a new rate schedule and documentation that the utility must provide the city for a power supply agreement (*ER20-869*).

Prescott filed its *complaint* against SWEPCO, an American Electric Power subsidiary, and MISO last April, but the issue behind the complaint can be traced to the 2013 integration of Entergy into the RTO. The city opposed Entergy's integration because it would be moved into MISO and served by a pseudo-tie from SPP member SWEPCO under a power supply agreement. SWEPCO proposed eight years ago to build a new transmission line to buffer the city from excessive charges from MISO, but it was never built.

Prescott's 2019 complaint claims that the failure of MISO and SWEPCO to guard it from congestion have pinned the city with about $770,000 per year in duplicate congestion charges and unreasonable transmission rates. SWEPCO neither hedged the city's transmission congestion risks nor protected it from rate pancaking, abandoning duties under the power supply agreement, Prescott contended.

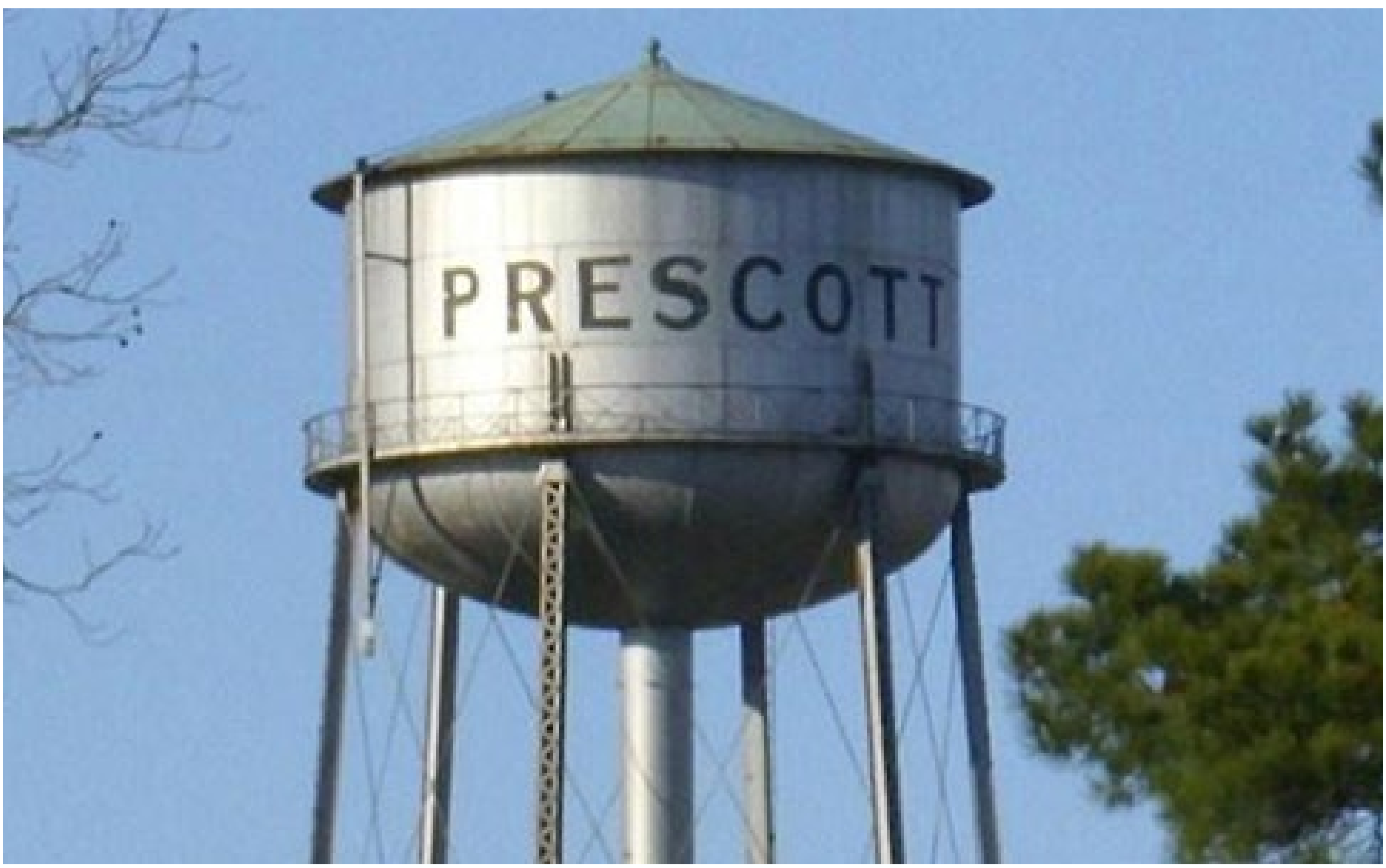
The situation also spurred SWEPCO to file a separate complaint alleging MISO violated its joint operating agreement with SPP regarding congestion charge assessments for loads that are pseudo-tied out of MISO and into SPP. The utility said the charges resulted in a $963,974 overpayment to MISO for one four-month period in 2016. A FERC investigation into MISO and SPP's potentially overlapping congestion charges is ongoing. (See *FERC Sets Briefings on MISO, SPP Congestion Fees*.)

Under the settlement agreement approved Wednesday, SWEPCO must file updated depreciation rates as formula rate inputs to FERC whenever the Louisiana Public Service Commission, Arkansas Public Service Commission or the Public Utility Commission of Texas approve changes to the utility's state depreciation rates that would affect Prescott's rates. If four years pass without an update, SWEPCO must make a FERC filing to update its depreciation rates.

The settlement also holds SWEPCO to providing Prescott with an annual populated formula rate, "including detailed work papers and other relevant supporting documentation, and to responding to Prescott's requests for additional data related to the formula rate calculations."

Finally, SWEPCO must also detail all RTO transmission charges and MISO market charges in its monthly invoices to Prescott.

FERC trial staff said the settlement agreement "reflects thoughtful and reasoned negotiations undertaken by all participants in good faith." ■



City of Prescott, Ark., water tower | *Waymarking*

MISO News

DOJ Joins NextEra Appeal of Texas ROFR Ruling

By Tom Kleckner

The U.S. Department of Justice last week again threw its weight behind NextEra Energy's ongoing effort to repeal a Texas law giving incumbent transmission companies the right of first refusal to build new power lines in the state.

Attorneys with the department's Antitrust Division filed an *amicus brief* with the 5th U.S. Circuit Court of Appeals in New Orleans (20-50160), where NextEra Energy Capital Holdings and four other NextEra transmission owner/developer entities have appealed a U.S. district court's February decision to not overturn Texas *Senate Bill 1938*. (See *NextEra Appeals Court Decision on Texas ROFR Law*.)

Assistant Attorney General Makan Delrahim and other division attorneys urged the 5th Circuit to vacate the district court's judgment and remand the motion to dismiss. The division also filed a brief in NextEra's lawsuit before the U.S. District Court for the Western District of Austin. (See *DOJ Weighs in on Texas ROFR Lawsuit*.)

DOJ questioned whether the district court properly dismissed a dormant Commerce Clause challenge to SB 1938. The legislation, passed last May, essentially allows only incumbent transmission companies to build new power lines in Texas by granting regulatory certificates of convenience and necessity to the owners of the endpoints of a new transmission line.

Delrahim noted that the Commerce Clause gives Congress the power to regulate interstate commerce and that the Supreme Court has interpreted the clause to contain the negative implication that "strikes at one of the chief evils that led to the adoption of the U.S. Constitution, namely, state tariffs and other laws that burdened interstate commerce."

NextEra has used the same argument in its appeal before the 5th Circuit.

In its brief, DOJ said the district court made three analytical errors in its decision, including:

- Erring in its evaluation of discrimination, improperly distinguishing "binding Supreme Court precedent articulating principles of 'ordinary Commerce Clause jurisprudence,'" failing to consider in-state physical presence requirements that are "viewed with particular suspicion" and affording improper significance to the location of a utility's parent company.
- Misreading and misapplying precedent from the Supreme Court ruling in *General Motors Corp. v. Tracy* to a "noncompetitive, captive market in which the local utilities alone operate." DOJ said, "The unique factors and concerns for utility markets that determined the outcome in *Tracy* are not present here and were not evaluated by the district court."
- Failing to weigh whether any of the alleged burdens from SB 1938 "substantially outweigh the law's putative benefits," as required under precedent. ■

Makan Delrahim

NextEra Energy subsidiary Lone Star Transmission lines | *Lone Star Transmission*

NY Examines Grid Transition Modeling, Reliability

By Michael Kuser

NYISO stakeholders last week explored detailed assumptions and modeling descriptions for a study on transitioning the New York grid to a cleaner future.

Roger Lueken and Sam Newell of the Brattle Group *presented* the Installed Capacity/Market Issues Working Group (ICAP-MIWG) with the thinking behind the study, which will simulate market operations and investment through 2040 to inform ISO staff and stakeholders on market evolution. (See *NYISO Focus Turns to Grid 'Transition'*.)

"The model is reasonable for painting a broad-brush picture of how the supply and demand will look in the future," Newell said. "It's not a super granular model; it's zonal, with a 'bubble' [representation] transmission layout, and is a somewhat stylized representation of the generation fleet where we aggregate individual units.

"There are a lot of unknowns currently about how we will meet the state goals, and what kinds of new resources will come in," Newell said.

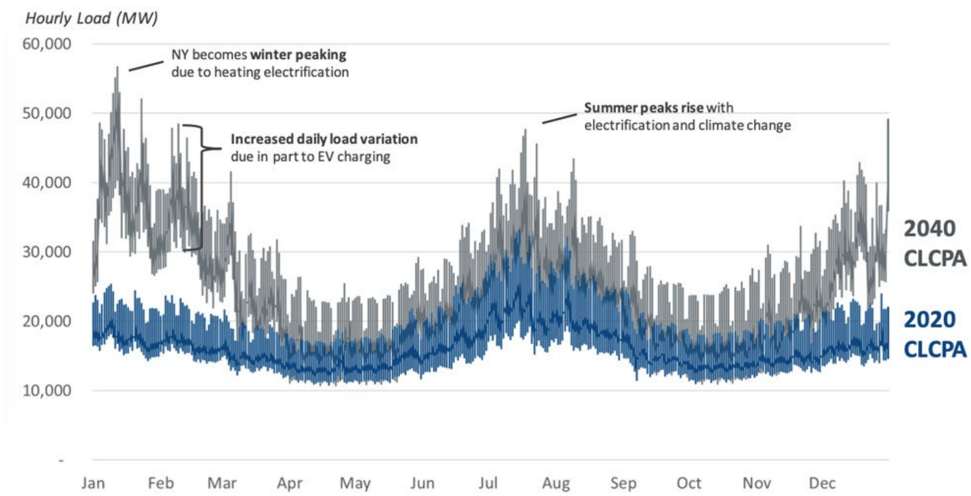
The modeling helps the ISO answer several questions, he said, such as what types of renewable resources will be needed to meet the Clean Energy Standard, including flexible resources and storage, and how electrification will affect load profiles and market operations.

"Wow, the world is so different now, three weeks after our last meeting, but we're just building on what we did then to provide more detail on the assumptions and on some of the modeling approaches," Newell said.

New York Gov. Andrew Cuomo in February *proposed* 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. (See *Cuomo Proposes Streamlining NY's Renewable Siting*.)

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. It also nearly quadrupled New York's offshore wind energy target to 9 GW by 2035.

The CLCPA's clean energy mandates also include doubling distributed solar generation to 6 GW by 2025, deploying 3 GW of energy



Electrification and climate change are forecast to affect load shapes. | *The Brattle Group*

storage by 2030 and raising energy efficiency savings to 185 trillion BTU by 2025.

Modeling Approaches

David Clarke, director of wholesale market policy for Power Supply Long Island, asked

"Wow, the world is so different now, three weeks after our last meeting, but we're just building on what we did then to provide more detail on the assumptions and on some of the modeling approaches."

—Sam Newell, The Brattle Group

how the study would simulate the impact of shortage pricing on energy revenues in the CLCPA future, which might hinge on the supply-demand balance and the amount of surplus capacity in the system.

"We are only partly representing [shortage pricing] in the study," Newell said. "First of all, we're not necessarily representing all of the features of either extreme net load conditions that could lead to shortage pricing, nor are we fully representing the dynamic challenges of ramping, and so we're not fully going to capture that, even if we do represent the upgrade in demand reserve curves in the model.

"Secondly, we're not actually designing this study to explore the different ways to implement enhanced shortage pricing, for example, through a richer demand curve," Newell said. "That actually takes a lot of design and is tricky to do well."

In modeling generators, Lueken said the study is accounting for known retirements and additions to occur over the next few years and not just existing resources, as in the ISO's 2019 *Gold Book*.

"So, for example, we are accounting for the potential for downstate peaker retirements due to the new NO_x rule," Lueken said. "We're currently planning to assume that downstate peakers built before 1986 retire, that frame units built after 1986 retire, that the aero-derivative units built since 1986 could, instead of retiring, decide to economically retrofit. However, we're re-evaluating these assumptions based on the compliance plans the generators have submitted to the ISO."

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The new NO_x regulations go into effect May 1, 2023, with initial rate limits of 100 parts per million on a dry volume basis, corrected to 15% oxygen. Generator compliance plans were due March 2. (See *NY DEC Kicks off Peaker Emissions Limits Hearings*.)

The study also models the declining capacity value of wind, solar and storage.

"The capacity value of the 5,000th MW of solar will be much lower than the first megawatt of solar because as you get so much solar in the system, it tends to shift the hours that capacity is needed to other hours in which the solar is not generating," Lueken said. "It's the same for wind, and there's a similar dynamic in place for energy storage."

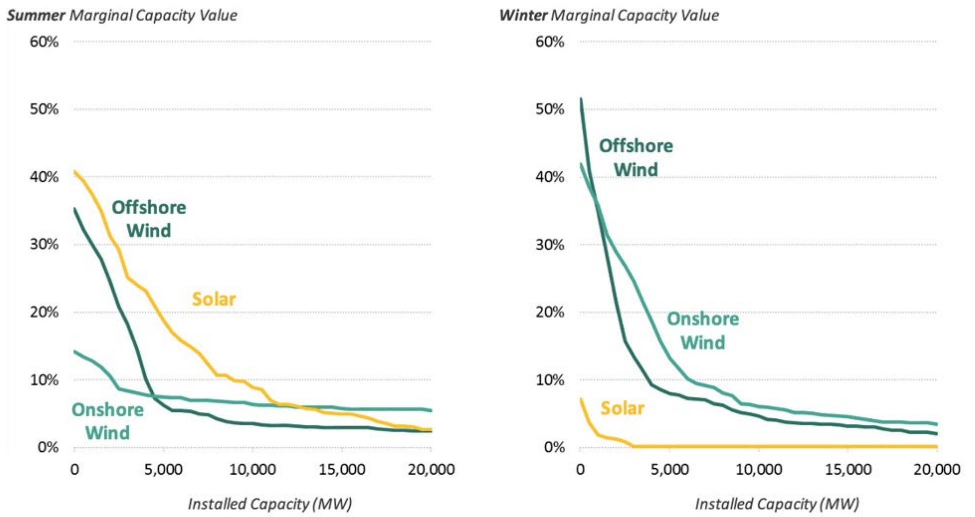
The high-level approach to develop the relationship between the amount of resources deployed and the capacity value of these resources entails varying the amount of each technology in turn while holding everything else constant, he said.

"For all the resources, the capacity value falls off quite a bit when you have 10,000 MW deployed," Lueken said.

Capacity Market and Reliability

Clarke *presented* a study by PA Consulting and the Long Island Power Authority on how the transition to renewable energy resources will impact the ISO's installed capacity market, moving to a system dominated by low variable-cost, high fixed-cost resources from one now dominated by the opposite: high variable-cost, low fixed-cost units.

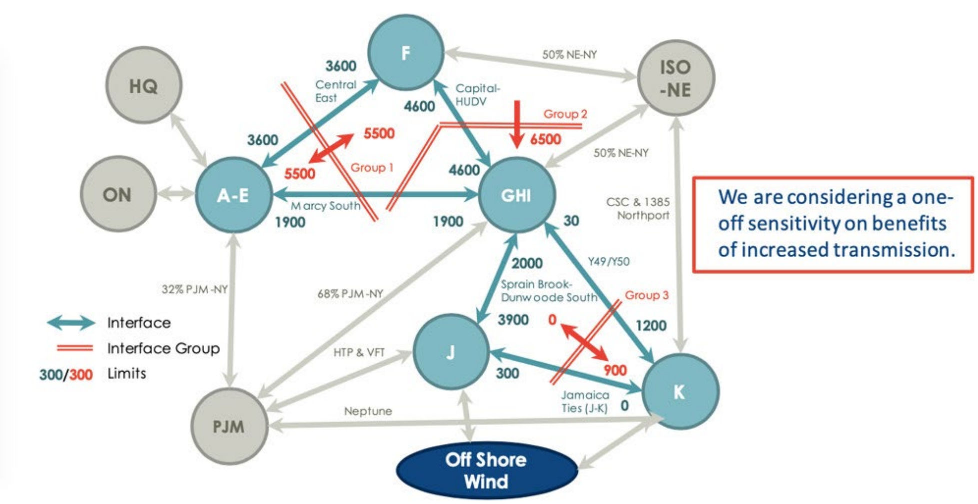
"We are basing our capacity market on the premise that new capacity is needed," Clarke said. "If you have to add capacity for something and it's not monetized [in the capacity market], in this case greenhouse gas abatement, the premise that you're going to need new capacity for reliability is really no longer a valid premise.



Modeling the capacity value of wind and solar. | *The Brattle Group*

"Making a more granular market, making sure there are sufficient market signals for generators to recover the 'missing money,' breaking down what things capacity is providing, different kinds of capacity and paying them for things they are providing — that is the kind of approach I see as being necessary in the long run," Clarke said.

Voluntary bilateral markets should continue, but the underlying market price should be disaggregated. These structural changes are necessary in the long run, as the existing structure may not best advance the state's clean energy mandates, he said.



In conjunction with NYISO, Brattle developed a 5-zone "pipe-and-bubble" representation of the New York grid. | *The Brattle Group*

"As energy margins and prices are declining, [and] the needed capacity is facing retirement, we recognize the essential need for long-term support for renewable resources," Clarke said.

Howard Fromer, director of market policy for PSEG Power New York, asked why a resource would need long-term support: "Is your own model still going to encompass out-of-market support? That seems to undermine everything you're talking about in terms of [market] efficiency."

"I don't think it needs to," Clarke said. "There will be attributes that will be monetized as we move in this direction, and attributes that aren't, so to the extent that we have not monetized the attributes that we need, there will be need for renewable resources and out-of-market payments in the long term."

The proper place to recognize the desirable attributes of renewable energy resources is in the energy market, said Mark Younger, president of Hudson Energy Economics.

"We have a multiyear effort to properly try and capture the value of those renewable attributes but have not yet been successful. But that is the proper way to capture it, to put a price on energy attributes and incorporate it into the market," Younger said.

Storage resources would still have value in scarcity conditions requiring a price signal, "but it's not a capacity signal. Trying to do it through a capacity price is a very blunt instrument being wielded by blind people," Younger said.

Clarke said the paradigm of trying to include everything possible in a 2040 energy price was

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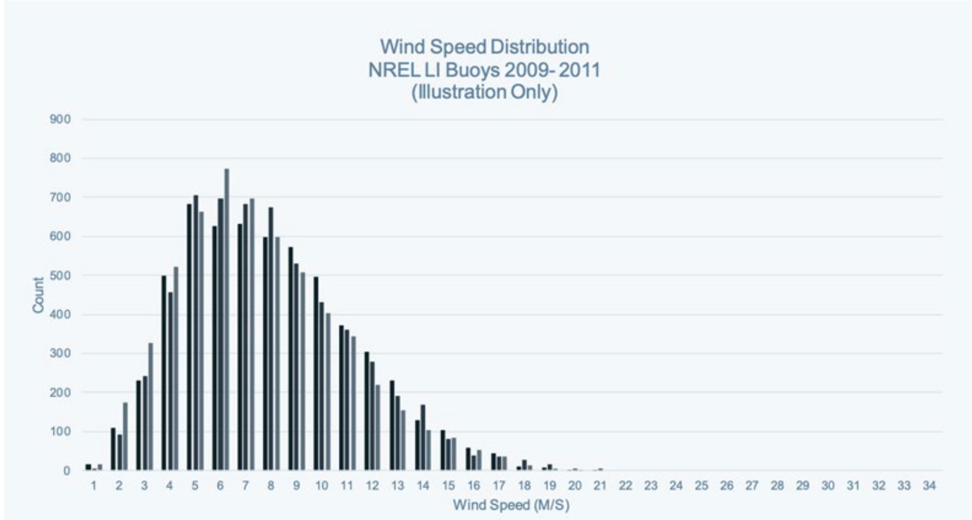
"not particularly workable."

Clarke highlighted differences among those who would allow highly volatile and perhaps extreme energy and ancillary service prices driven by flexible resource shortages to provide the incentive for their construction from those that would assure development of sufficient flexible resources through a targeted capacity payment.

"We do support the NYISO's proposal to enhance ancillary services revenues as a means of more efficiently distinguishing resources that can provide flexible resource services over and above those that cannot," he said. "However, we do recognize that an additional missing money payment for flexible capacity attributes could signal an appropriate mix.

"I see energy as declining in price and in value generally," Clarke said. "I also see some reliability challenges going forward — increasing ICAP requirements, net load shifting, a changing load shape and frequency of ramping, saturation of particular renewable resources in certain load pockets and continued need for firm dispatchable resources."

Clarke showed a graph indicating that offshore wind speed — and ultimately power output — is more broadly distributed than the duration of conventional generation outages.



Offshore wind speed (and ultimately power) is more broadly distributed than conventional generation outages. | *PA Consulting/LIPA*

"If the Long Island buoy data perfectly correlated with the sites offshore New York City, then the capacity value of offshore wind would be effectively zero," Younger said. "While this is informative to indicate that we probably are massively overvaluing the capacity value of wind, because there are so many hours with very low wind speed, it doesn't really take us beyond that observation." ■

PJM Rejects Ameren Challenge on Tx Project

By Michael Yoder

PJM is standing behind its original solution for congestion issues in the Met-Ed service territory in Pennsylvania, saying a $7 million rebuild of the 115-kV Hunterstown-Lincoln line was superior to a competing project from Ameren.

In a Feb. 11 *letter*, Jeffrey Hackman, senior director of transmission operations, technical services and business development for Ameren Transmission Company of Illinois (ATXI), asked the PJM Board of Managers to reconsider its decision to include the rebuild (Proposal HL_622) in the Regional Transmission Expansion Plan (RTEP) and to order RTO staff to "objectively and transparently re-evaluate" HL_622 and Ameren's competing proposal (HL_469).

"ATXI does not make this request lightly but believes it is necessary to ensure that the process is just and reasonable and that customers receive the benefit of the process, which is supposed to result in the more efficient and/or cost-effective project being selected," Hackman said.

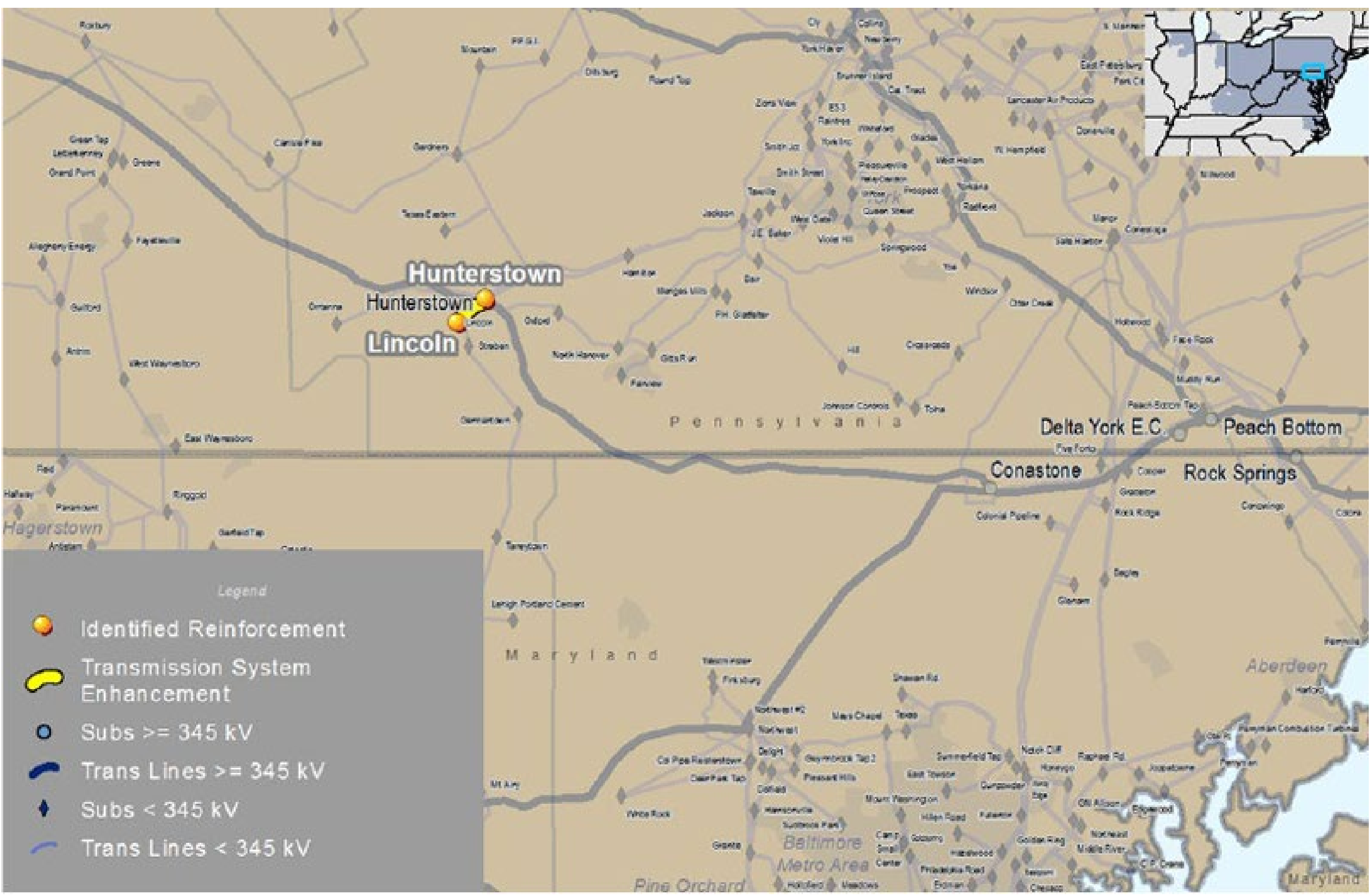
On Wednesday, PJM CEO Manu Asthana told Hackman in a *letter* that the RTO continues to support the rebuild.

"We have reviewed the record once again and determined that the selection was fully supported by our own staff's detailed analysis (which included meetings with your staff), the results of an independent consultant's review, and a review of the cost estimates of the Ameren proposal as compared to other competing proposals," Asthana wrote. "The results of our analyses were presented at the November 2019 Transmission Expansion Advisory Committee meeting. For these reasons and after this recent additional review of all of the underlying facts, PJM stands by the original selection decision."

Asthana's response may not be the end of the dispute. Hackman — who alleged PJM's actions violated FERC Orders 890 and 1000, and the PJM Operating Agreement and manuals — copied FERC commissioners and top staff on his letter. Asthana did the same in his response.

The line upgrade selected is proposed for Adams County, Pa., territory of FirstEnergy's Met-Ed, and was proposed by FirstEnergy's Mid-Atlantic Interstate Transmission (MAIT) subsidiary. MAIT signed a *designated entity agreement* to perform the rebuild last month (Project b3145).

It was selected from 19 greenfield and three upgrade proposals submitted by seven entities in response to a competitive window that closed in March 2019. The proposals' estimated costs ranged from $4.65 million to $290.95 million.



Location of the 115-kV Hunterstown-Lincoln line | *PJM*

Ameren's proposal called for installing a SmartValve — which manufacturer SmartWires *describes* as a "single-phase, modular, static synchronous series compensator (SSSC), [which] injects a leading or lagging voltage in quadrature with the line current, providing the functionality of a series capacitor or series reactor respectively" — on the Hunterstown-Lincoln line. PJM estimated its cost at $7.15 million.

The PJM cost analysis for HL_622 came in at $7.21 million.

Discretion and Transparency

In his letter, Hackman said Ameren staff expressed concerns to PJM regarding the process the RTO applied to evaluate proposals on two separate occasions: the 2014 30-day reliability window and the 2016/17 long-term market efficiency window.

Hackman said their concerns included a lack of specificity in the OA that "mystifies the basis of decisions" and a lack of transparency and consistency in the decisions on the merits of proposals.

In his response, Asthana said FERC Order 1000 creates "new opportunities, but also new complexities" in regard to new transmission technologies.

In the November 2019 *presentation* to the TEAC, PJM staff raised concerns with Ameren's proposal, citing "limited experience with [the] SmartValve device."

PJM also said Ameren's proposal had higher permitting risk than the rebuild because it required "new property for [a] substation due to [its] location near [a] historically sensitive area."

Staff concluded the rebuild would provide additional system capability, while the Ameren proposal could increase flexibility. But PJM said it would not be able to fully exploit the dynamic capabilities of the SmartValve without making changes to the day-ahead and real-time supervisory control and data acquisition systems.

It said the rebuild had a benefit/cost ratio of 76.41 versus 72.61 for the SmartValve.

Hackman said Ameren understands PJM has "considerable discretion" under its OA. "However, transparency is necessary when there is this level of discretion, and PJM staff appear to have forgotten that," Hackman wrote.

"PJM staff did not provide necessary details in the November TEAC to stakeholders explaining why the detailed feasibility review that was performed on Proposal HL_469 resulted in a 53.7% increase to the estimated cost of Proposal HL_469, causing the benefit-to-cost (B/C) ratio for the project to fall below the B/C ratio for Proposal HL_622," Hackman continued. "PJM failed to provide that information in a timely manner that allowed for review and discussion in the TEAC and before PJM staff presented their recommendation for approval to the PJM Board of Managers."

Asthana's letter did not address Ameren's B/C claim.

Will the dispute end up before FERC?

Asthana offered an olive branch. "We are always open to stakeholder input on potential process improvements and are committed to transparency and communication with stakeholders as part of the evaluation process," he said. "We appreciate Ameren's willingness to focus, at this point, on discussing with PJM and other stakeholders potential enhancements to our market efficiency competitive process and appreciate your proposals on these subjects." ■

PJM Preps 3rd Control Room, Plans for Sequestration

By Michael Yoder

No PJM dispatchers have tested positive for COVID-19 yet, but RTO officials are planning just in case their luck runs out.

During the weekly coronavirus update Friday, PJM officials were asked how they would respond if a dispatcher tested positive for the virus.

Paul McGlynn, PJM's executive director of system operations, said no control room workers have tested positive, but that the RTO has enough employees to fill gaps if someone becomes infected.

McGlynn said PJM's control center best practices document includes procedures for bringing back former employees in an emergency. "We look at staff that has previously worked in the control room and develop plans to get them trained and ready so that they could go back on the board if needed," McGlynn said.

Telecommuting Extended

Scott Heffentrager, PJM's chief security officer, said the RTO is extending telecommuting for all personnel until May 4. Heffentrager said the telecommuting measure does not apply to the control room staff, IT operations center, security or other critical on-site support personnel.

Crews have been prepping the PJM campuses for more than a week for sequestration — healthy workers required to remain on site if the pandemic becomes worse — if it becomes necessary. Heffentrager said crews are installing temporary bedding, entertainment, food and other accommodations for employees.

"We have not made the decision to go to sequestration, but this was just to prep the campus in the event that we do pull the trigger to do that," Heffentrager said.

Besides adding accommodations for employees, a team has also been working on converting PJM's control room simulator to a potential third control room in case of an emergency. Heffentrager said the control room is currently being tested, and security and compliance teams are converting the room to a "physical security perimeter" to meet NERC standards.

Generator Outage Coordination

PJM's David Schweizer updated stakeholders on generator outage coordination, saying most generators intend on going ahead with planned and maintenance outages despite the pandemic. He said the RTO continues to track any changes that members bring to PJM's attention, including planned outages.


David Schweizer, PJM | © RTO Insider

About 5% of the planned outages this spring have been canceled outright without being rescheduled, Schweizer said, with about 25% being deferred until later this spring, the fall and the spring of 2021. Schweizer said many generators are reducing the scope of the spring outages by supplementing them with short duration maintenance outages during off-peak hours.

PJM has also continued coordination with gas pipelines to make sure gas is still being sent to generators. Schweizer said teams are tracking any pipeline maintenance plans, especially those that could "affect generation in the PJM footprint."

Stakeholders are continuing to compile best practice information through a survey of generators that was started last month, Schweizer said. The survey was designed to be a portal to provide supplemental information to PJM so that the RTO is aware of issues related to outages, complications with contractor availability and other support needs.

Schweizer said the questionnaire is meant to be a "dynamic, ongoing survey" that will be updated regularly. He said one of the biggest concerns that has been voiced by generators are supply chain problems for outage-related materials coming from outside the immediate area.

"I think the thing we're seeing mostly is comments about contractor availability not being 100% assured due to the fact that many outages are relying on critical workforce and resources coming from out of state or even from overseas," Schweizer said.

Load Modeling

Elizabeth Anastasio, PJM senior meteorologist, said long- and short-term load forecasters are attempting to determine the impact of COVID-19 by comparing actual load with historical temperature and *load data*.

Anastasio said forecasters have been seeing some trends in load forecast errors.

After the first two weeks of March, the error in one of the short-term models fluctuated between +2% and -2%, Anastasio said, averaging out to a bias near zero for the forecast model.

In the last two to three weeks of March, she said forecasters observed the forecast error increase in magnitude, seeing an error of 4 to 6% depending on the time of day. She said the error has largely remained positive in that time, as the "models are over-forecasting almost exclusively."

Anastasio said the warmer-than-usual weather has been playing a role in lower load levels.

"We're doing our best to figure out how much of our decrease in load is due to the warmer temperatures and how much is due to COVID-19," she said.

Chris O'Leary of PSEG Energy Resources asked if Anastasio believes PJM will be able to quantify the effect of COVID-19 with the higher-than-normal March temperatures and other factors.

Yes, Anastasio said. At least three or four methodologies are being pursued, she said, with each one having limitations that include simplistic modeling and subjectivity.

"What we've seen from early results of this analysis is that many of the methodologies are converging on a similar solution," Anastasio said. "I suspect that we'll be able to present a little bit more in this line at our Operating Committee meeting presentation" on April 15.

Additional Updates

PJM's Donnie Bielak provided an update on transmission outage coordination, saying most planned transmission upgrades are proceeding on schedule. Although some transmission operators decided in late March to defer nonessential work until later months, time-sensitive work is proceeding as planned, Bielak said.

Michael Hoke, PJM's senior lead trainer, updated stakeholders on operator training schedules. Hoke said his team is in the process of finalizing online simulations. He said the online simulations are used for operators who need a certification renewal in the next month or two and need simulation hours to complete the process. ■

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FERC Sets Hearing on FirstEnergy PPAs

By Rich Heidorn Jr.

FERC last week ordered a paper hearing to consider FirstEnergy Solutions' bid to void power purchase agreements with wind generators and others as part of its bankruptcy proceeding (EL20-35).

The commission acted days after the 6th U.S. Circuit Court of Appeals issued a mandate on its December 2019 order overruling a U.S. bankruptcy court's May 2018 injunction that prevented FERC from issuing any order requiring FES to continue complying with its obligations under the contracts. The appellate court also reversed the bankruptcy court's ruling allowing FES to reject the contracts.

FES changed its name to Energy Harbor upon *emerging* from Chapter 11 bankruptcy on Feb. 27 with former bondholders owning 50% of the equity. (See *FERC OKs FES Sale to Bondholders*.)

The 6th Circuit ruled "that the public necessity of available and functional bankruptcy relief is generally superior to the necessity of FERC's having complete or exclusive authority to regulate energy contracts and markets."

But it said that, although the bankruptcy court's jurisdiction is "superior to FERC's position," it is not exclusive and that the court had exceeded its authority.

"Through this rash and unnecessary overreach, the bankruptcy court has prevented FERC from timely completing an investigation into or holding a hearing about the public interest in the proposed rejection of these contracts, which … would have been appropriate and might have been valuable or beneficial to the ultimate determination," the 6th Circuit said.

The appellate court said the bankruptcy court must consider the impact of rejecting the contracts on the "public interest," rather than using the "business judgment" standard that normally applies in bankruptcy cases.

The 6th Circuit required that the bankruptcy court give the commission "a reasonable accommodation" in providing its views to the bankruptcy court with respect to whether the rejection is consistent with the public interest.

The appeals court said that when a Chapter 11 debtor asks the bankruptcy court for permission to renege on energy contracts that are FERC jurisdictional, the bankruptcy court "must consider the public interest and ensure that the equities balance in favor of rejecting the contract, and it must invite FERC to participate and provide an opinion in accordance with the ordinary FPA approach (e.g., under the *Mobile–Sierra* doctrine)."

Kyger Creek Power Plant

Mobile-Sierra requires FERC to presume that the rate set out in a freely negotiated wholesale energy contract meets the Federal Power Act's "just and reasonable" requirement unless the commission determines that the contract seriously harms the public interest.

The Supreme Court has ruled that the public interest can require canceling contracts that impair the financial ability of a public utility to continue its service, imposes excessive burdens on consumers or is "unduly discriminatory."

FERC on March 30 said that it was initiating a hearing and investigation under FPA Section 206 in order to develop a record that would inform the commission's views on the contracts' cancellations.

The commission ordered Energy Harbor to submit a filing within 30 days, identifying each contract the company seeks to reject, the status of any negotiations with the contract counterparties and an explanation of why the rejection meets the public interest standard.

"To the extent that such explanation relies on the standard that the contract might impair Energy Harbor's financial integrity, include a discussion of the effect of the completed bankruptcy reorganization and Energy Harbor's emergence from Chapter 11 bankruptcy protection on the application of this standard," FERC directed.

Counterparties and intervenors will have 30 days to respond to Energy Harbor's filing.

"Any counterparty that does not submit such a response shall be deemed to acquiesce in the rejection of its contract for the purpose of the commission's public interest determination," FERC said.

The commission said it plans to issue an order within 180 days. The refund effective date will be the date of the publication of last week's order in the *Federal Register*.

The contracts FES sought to renege were with Allegheny Ridge Wind Farm (Phase 1 and Phase 2), Blue Creek Wind Farm, Casselman Windpower, High Trail Wind Farm, Krayn Wind, Meyersdale Windpower, North Allegheny Wind (Phase 3 and Phase 4), Maryland Solar and Forked River Power.

FES also sought to escape the multiparty intercompany power agreement with Ohio Valley Electric Corp., which runs through June 30, 2040. OVEC provides power from its two coal-fired generating plants — the 1.1-GW Kyger Creek in Cheshire, Ohio, and 1.3-GW Clifty Creek in Madison, Ind. — to Energy Harbor and seven other corporate "sponsors." ■

NJ Investigating Alternatives to PJM Capacity Market

MOPR Comment Deadline Extended

By Michael Yoder

New Jersey regulators have taken the first step in determining whether the state should remain in PJM's capacity market or to go in a different direction to meet the state's electricity needs.

The New Jersey Board of Public Utilities voted March 27 to investigate if staying in the capacity market will impede Gov. Phil Murphy's goals of 100% clean energy sources in the state by 2050 or increase consumer costs (Docket No. *EO20030203*). (See *NJ Unveils Plan for 100% Clean Energy by 2050*.)

If not achievable, board members have instructed staff to examine alternatives to the market.

"Taking control of our own resource mix may be the only way to stop the Trump administration's attempts to prop up fossil fuels to the detriment of our clean energy program," said NJBPU President Joseph L. Fiordaliso in a press release. "We will do everything in our power to prevent that from happening."

State officials said the investigation stems from FERC's Dec. 19 order expanding the PJM minimum offer price rule (MOPR) to all new state-subsidized resources. New Jersey was among several states to ask FERC in January to rehear the order. (See *PJM MOPR Rehearing Requests Pour into FERC*.)

FERC on March 31 extended the deadline for comments on PJM's compliance filing in the MOPR proceeding to May 15, from April 22, in response to a request by the Public Utilities Commission of Ohio (*ER18-1314-003*). PUCO had sought a delay until the end of the coronavirus emergency or no earlier than June 1. Commissioner Richard Glick dissented, saying he would have granted PUCO's request. Opposing the delay were the PJM Power Providers Group and the Electric Power Supply Association, which *said* in a joint filing: "PJM has not conducted a capacity auction since May of 2018, and the lack of market certainty has harmed both consumers and suppliers."

State officials are concerned the expanded MOPR will prevent new offshore wind generation and nuclear units receiving zero-emission credits from clearing the capacity market, forcing state residents to pay twice for capacity. The state has set a goal of procuring 7,500 MW of offshore wind by 2035. (See *NJ Sets Schedule for OSW Procurements*.)

The board directed its staff to conduct the process through written comments, technical conferences and public hearings.

The written comment period, which is open through April 29, asks for responses to several questions, including the following:

- Can New Jersey utilize the fixed resource requirement (FRR) alternative to adequately satisfy the state's resource needs?
- Can it utilize the FRR to accelerate achievement of clean energy goals stated in its *Energy Master Plan*?
- Can other mechanisms, such as a clean energy standard or clean energy market, facilitate the achievement of the state's clean energy goals?
- What "practical limits" may result from the state's location along the Atlantic Ocean and the NYISO seam?
- Should the state consider creation of a state power authority?

Hope Creek Nuclear Generating Station in New Jersey

The board expects the investigation to conclude in the third quarter of 2020.

Cynthia Holland, director of BPU's Office of Federal and Regional Policy, presented the investigation proposal at the March 27 meeting.

Board Member Upendra Chivukula asked Holland if an exact timeline to come up with a resolution has been put in place. "This is an important initiative, so a time frame will have some kind of inputs that come from the stakeholders," Chivukula said.

Holland said besides the written comments that are to be filed by April 29, the staff does not yet have a finalized date for issuing its recommendations to the board. ■

PJM News

FERC Rejects PJM Tariff Revisions for NJ Merchant Operators

By Michael Yoder and Rich Heidorn Jr.

FERC has ruled that two merchant transmission operators in New Jersey are still liable for some cost allocations under PJM's Regional Transmission Expansion Plan (RTEP) despite converting from firm to non-firm service after the cancellation of the "Con Ed-PSEG wheel" in 2017 (*ER18-680*).

In its ruling March 31, FERC said despite the conversion from firm to non-firm transmission withdrawal rights (TWRs) that would limit exposure to future RTEP costs, Linden and HTP were still liable for RTEP costs previously allocated while still under their firm TWR status.

Linden VFT and Hudson Transmission Partners (HTP) own merchant transmission facilities that carried power into New York City as part of the former Con Ed-PSEG wheel, in which 1,000 MW were exported from upstate New York to PJM through Public Service Electric and Gas facilities in northern New Jersey, and then exported to the city. Consolidated Edison and PSE&G canceled the agreement in April 2017, prompting HTP and Linden to convert their firm TWRs to non-firm TWRs.

FERC approved the TWR changes in orders in December 2017 (*EL17-90, EL17-84*). (See *NJ Merchant Tx Operators Win Relief on Upgrade Costs*.)

The commission had previously found that merchant transmission facilities with firm TWRs are "like loads in that they remove energy from PJM, thus requiring PJM to study deliverability of energy from the PJM system to the point of interconnection."

Linden VFT's interior | *Energy Initiatives Group*

PJM interpreted the December 2017 orders as directing that all allocations to Hudson and Linden cease as of Jan. 1, 2018, and proposed to pro-rate the allocations to the remaining zones. But the commission said that the companies should only be relieved from ongoing cost allocations in Schedule 12-Appendix A, which PJM redetermines annually based on the level of firm transmission withdrawal rights. It said the companies remain liable for costs of lower-voltage facilities that use the pre-Order No. 1000 violation-based distribution factor (DFAX) method and economic projects that are allocated on the load energy payment method, which is also fixed at the time the projects are included in the RTEP.

"Our finding here accords with the commission's prior holding that the merchant transmission facilities remain responsible for targeted market efficiency projects, because these calculations were not based on the level of firm transmission withdrawal, but on the basis of congestion savings," FERC said. "The merchant transmission facilities continue to benefit from these savings regardless of whether they hold firm transmission withdrawal rights. For these reasons, we reject PJM's proposal to reassign cost responsibility from Hudson and Linden for the economic projects identified in PJM's compliance filing."

FERC ordered PJM to submit a filing within 60 days correcting the allocations.

The New Jersey Board of Public Utilities had protested PJM's filing, arguing that eliminating the RTEP allocation to HTP and Linden would "result in unduly burdensome costs on PJM customers, particularly in northern New Jersey, at a preference to New York load" and was "particularly egregious in light of the benefits retained by New York load regardless of the character of Hudson's and Linden's transmission rights."

FERC ruled that the BPU's arguments were "beyond the scope of a challenge to a compliance filing" and that they should instead be raised in a rehearing request, not a protest to the compliance filing implementing that order.

The BPU has appealed FERC's rulings on Linden and HTP's TWRs, and the reassignment of Con Ed's cost responsibility assignments for RTEP projects including the Bergen-Linden Corridor project, to the D.C. Circuit Court of Appeals.

Linden VFT's exterior | *Joseph Jingoli & Son*

Rehearing Denied

In a related ruling March 31, the commission rejected rehearing of its March 2018 ruling accepting PJM's annual cost responsibility assignments for regional transmission facilities and lower-voltage facilities included in the RTEP for 2018 (*ER18-579-002*).

PJM transmission owners American Electric Power, Dayton Power and Light, Dominion Energy, Exelon, FirstEnergy, PPL and PSE&G challenged PJM's decision that Linden and HTP should not have a cost assignment for Schedule 12-Appendix A projects for 2018.

"PJM transmission owners advance no argument on rehearing to explain why merchant transmission facilities must be responsible for cost allocation assignments for a year in which they hold no firm transmission withdrawal rights," the commission said.

The commission also dismissed as moot Dominion's rehearing request over PJM's initial assignment of 100% of the costs of the Loudoun-Brambleton 500-kV and 230-kV lines (project b2372) to the Dominion zone.

FERC noted that PJM responded to Dominion's original protest by conceding the utility was correct and that the project should be allocated as a regional facility needed for reliability, with 50% of costs allocated via the load-ratio share and 50% using the solution-based DFAX. PJM filed a modified allocation assigning two-thirds of the costs to the Dominion zone and one third to the APS zone, which FERC accepted in August 2018 (*ER18-2028*). ■

SPP News

SPP's Western Market Protocols Approved

By Tom Kleckner

SPP stakeholders last week unanimously approved the initial set of *protocols* that will guide the RTO's Western Energy Imbalance Service (WEIS) market in the Western Interconnection.

The Western Markets Executive Committee, meeting by phone on Friday, also formally disbanded the WEIS Protocol Review Task Force, which drafted the protocols. It will be replaced by the *Western Markets Working Group*, which has scheduled its first meeting for April 29. (See *SPP Launches Western Market Groups*.)

Gary Cate, SPP | © RTO Insider

"I think [the protocols] are in a really good spot," said SPP's Gary Cate, who worked on the task force. "We know of some sections that need cleanup … but this is a living document. There are things in here that both the SPP team and the protocol team thought this is how the market should work. If we're going to find it doesn't work or what we thought is clear is not clear, we'll clean those up or add new sections."

The protocols' settlements section and some formulas need to be revised, Cate said. Connectivity testing, market trials and parallel operations will likely highlight other revisions that need to be made, using a revision request process modeled on SPP's.

David Kelley, SPP | © RTO Insider

To emphasize the point, David Kelley, SPP's director of seams and market design, noted that the grid operator's Integrated Marketplace protocols are currently in version 75.

"That gives you a flavor of how dynamic the protocols are," Kelley told the committee. "You guys have the ownership of these protocols and this doc. It'll change as often as you guys approve it to be changed."

When it came time to vote, Chair Tim Vigil, with the Western Area Power Administration's Colorado River Storage Project, asked whether committee members had any questions. He was greeted by dead silence, a sign of the impending vote.

The task force approved the protocols without opposition. Each of the companies on the committee also had a representative on the task force.

The WEIS market is scheduled to go live next February. SPP will centrally dispatch energy from the participants every five minutes to provide price transparency and bilateral trades.

The market, modeled on SPP's Energy Imbalance Market that operated from 2007 to 2014, has attracted eight participants. (See *SPP Board OKs $9.5M to Build Western EIS Market*.) ■

FERC: SPP Withdrawal Deposit not Membership Barrier

By Tom Kleckner

FERC last week clarified that non-transmission owning members of SPP are still subject to a $50,000 deposit for if they withdraw from the RTO, rejecting environmental organizations' complaint that the deposit constitutes a barrier to membership (*EL19-11*).

The organizations — Advanced Power Alliance (APA), Clean Grid Alliance, Climate + Energy Project, Natural Resources Defense Council, Sierra Club, Southern Renewable Energy Association, Sustainable FERC Project and Western Resource Advocates — filed a request for clarification in early February following FERC's rejection of SPP's request for rehearing of the commission's decision to end the RTO's exit fee for non-transmission owners. They objected to what they called the commission's "reinstatement" of the $50,000 deposit in its December order. (See *FERC Denies Rehearing of SPP Exit Fee Decision*.)

FERC reminded the groups that it had ruled that non-TOs "should only be exempt from paying a share of SPP's long-term financial obligations, rather than all existing obligations associated with membership withdrawal." The deposit represents the costs SPP would incur to process a member's withdrawal from the RTO, while the fee represents the sum of the withdrawing member's share of SPP's outstanding long-term financial obligations and its obligations at the time of withdrawal, including any unpaid dues or assessments.

Inside SPP's control room | SPP

The commission also rejected their arguments that the deposit requirement represents a barrier to membership and is unjust and unreasonable. FERC also said the groups missed the 30-day deadline following a commission decision to file a request for rehearing and ruled their motion as a late-filed request.

APA and the American Wind Energy Association filed the initial successful complaint that resulted in FERC last April ordering SPP to end charging an exit fee for members that are not TOs or load-serving entities. (See *FERC Tells SPP to End Exit Fee for Non-TOs*.) SPP had estimated the fee could amount to as much as $630,000 for entities without load.

In December, FERC rejected a rehearing request by SPP and its LSEs, along with the RTO's proposal to lower the exit fee to $100,000. It ordered the grid operator to submit another proposal "that adequately explains" why the exit fee for non-TOs is just and reasonable and "not a barrier to membership … and not excessive as a means of ensuring stability in membership and members' financial commitment." ■

SPP News

SPP Seams Steering Committee Briefs

Joint System Planning with MISO Gaining Steam

SPP and MISO are picking up the pace of developing their 2020 coordinated system plan (CSP), staff told the Seams Steering Committee last week.

SPP's Neil Robertson said both RTOs have published project needs to their individual stakeholder groups. Once the project submissions come in, he said, staff will begin the evaluation phase of those projects. The RTOs will reveal their final portfolios in October and December, respectively.

The RTOs agreed to conduct a CSP this year to determine whether there are any interregional projects worth pursuing. (See *MISO, SPP Staff Recommend 2020 Joint Study*.)

SPP Director of System Planning Casey Cathey once again expressed his optimism that the CSP will result in a joint project this year. Three previous attempts between SPP and MISO have been fruitless, but Cathey said there has been a large jump in MISO's prevailing north-to-south system flows.

"The likelihood of economic and reliability projects that meet the thresholds in the [joint operating agreement] is much higher this cycle," he said. "That's just by nature of MISO updating their models and SPP's regional approach to reflect their range of futures and growth, including all new generation in the north."

MISO's models include additional wind generation in its northern regions not found in SPP's models. Cathey said staff are aware of the situation and pondering additional sensitivities to meet those needs.

SPP, AECI Agree to Joint Study

SPP has also agreed to a joint CSP in 2020 with Associated Electric Cooperative Inc. following a March 30 meeting of their Interregional Planning Stakeholder Advisory Committee, Robertson told the SSC.

A scope document has been approved, and solutions will soon be shared. Robertson said the entities plan to finish their analysis in August, after which SPP will have to file a contract with FERC.

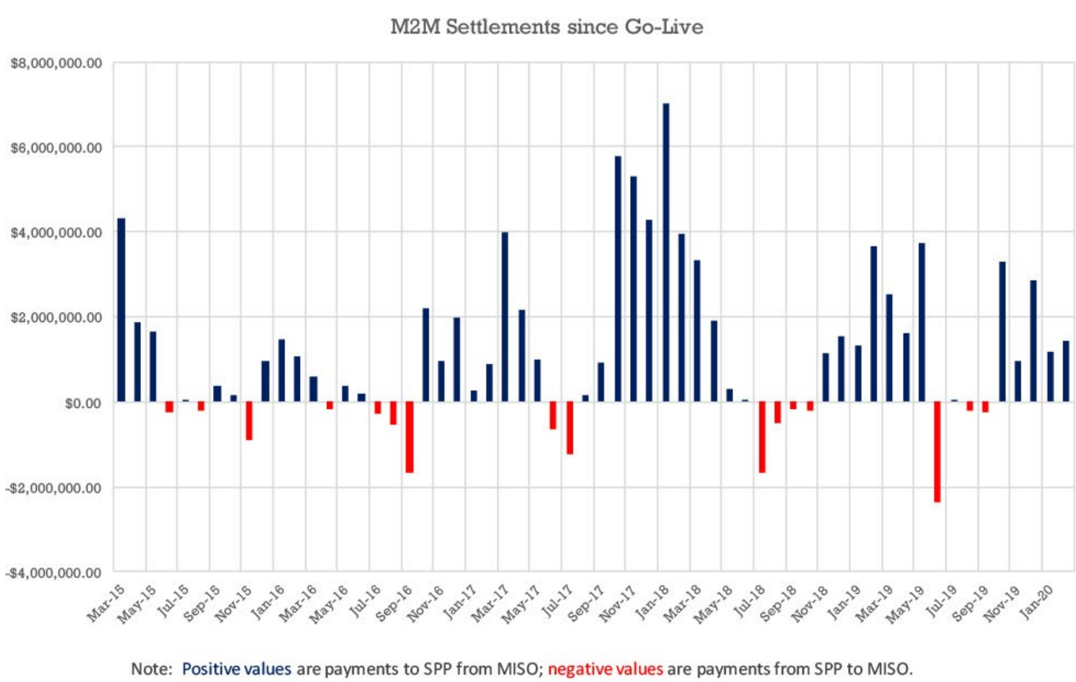
The joint CSP could include a 345-kV competitive project approved in January by the RTO's board as part of the 2020 *SPP Transmission Expansion Plan*. Robertson said the $152 million, 105-mile Work Creek-Blackberry upgrade in Kansas and Missouri will be included in the study to determine whether there are any system reliability impacts. (See "Directors Approve $545M Transmission Expansion Plan," *SPP Board of Directors/MC Briefs: Jan. 28, 2020*.)

Committee Endorses Study of MISO RDT Flows

The committee unanimously endorsed a summary report on the effect of MISO's contract path to its southern footprint, after first inserting language making it clear the study "should not be used to draw broad conclusions about the impact of MISO RDT [regional directional transfer] flows" to SPP's region.

The study was inconclusive as to whether MISO's above-capacity RDTs created a "pattern of financial harm." Several members pointed out the analysis does not consider the costs of real-time deviations from day-ahead market positions or the economic redispatch of the MISO system. (See "Congestion Study Inconclusive on MISO Contract Path," *SPP Seams Steering Committee Briefs: March 12, 2020*.)

The study looked at the SPP day-ahead market's external flows and solution costs to determine whether RDTs above the contract path capacity between MISO's South and Midwest sub-regions created additional congestion or operating costs for SPP's market. MISO is limited to 1,000 MW of contracted, firm capacity over the contract path as a result of a 2015 settlement agreement. (See *SPP, MISO Reach Deal to End Transmission Dispute*.)



SPP's market-to-market settlements were once again in its favor in February. | *SPP*

SPP Again Winds up with Positive M2M Settlements

SPP recorded another $1.06 million of market-to-market (M2M) settlements in February, the fifth straight month — and 44th in 60 months — the M2M process with MISO has settled in its favor.

SPP has now earned $73.59 million from M2M settlements with its neighbor since the two began the process in March 2015. The process provides a compensation mechanism when SPP or MISO have to re-dispatch transmission around congested flowgates.

Temporary and permanent flowgates on the RTOs' seam were binding for 453 hours during January. Temporary flowgates accounted for 385 of the binding hours. ■

— Tom Kleckner

Company News

AEP Warns of ‘Adverse’ Effects from Coronavirus

Spring Maintenance Outages at Risk

By Tom Kleckner and Rich Heidorn Jr.

American Electric Power last week warned shareholders that the company’s financial condition and operations could be “adversely affected” by the COVID-19 pandemic as other utilities considered delaying spring maintenance.

In an *8-K filing* with the Securities and Exchange Commission, AEP said it is working to mitigate the pandemic’s “potential risks” and that it will continue to review and modify its plans as conditions change.

“Despite our efforts to manage these impacts to the company,” AEP said, “their ultimate impact also depends on factors beyond our knowledge or control, including the duration and severity of this outbreak as well as third-party actions taken to contain its spread and mitigate its public health effects. Therefore, we currently cannot estimate the potential impact to our financial position, results of operations and cash flows.”

The Columbus, Ohio-based company said it has updated and implemented a company-wide plan that addresses specific aspects of the coronavirus pandemic. The plan provides guidance on emergency response, business continuity and precautionary measures to take on behalf of employees and the public, the company said.

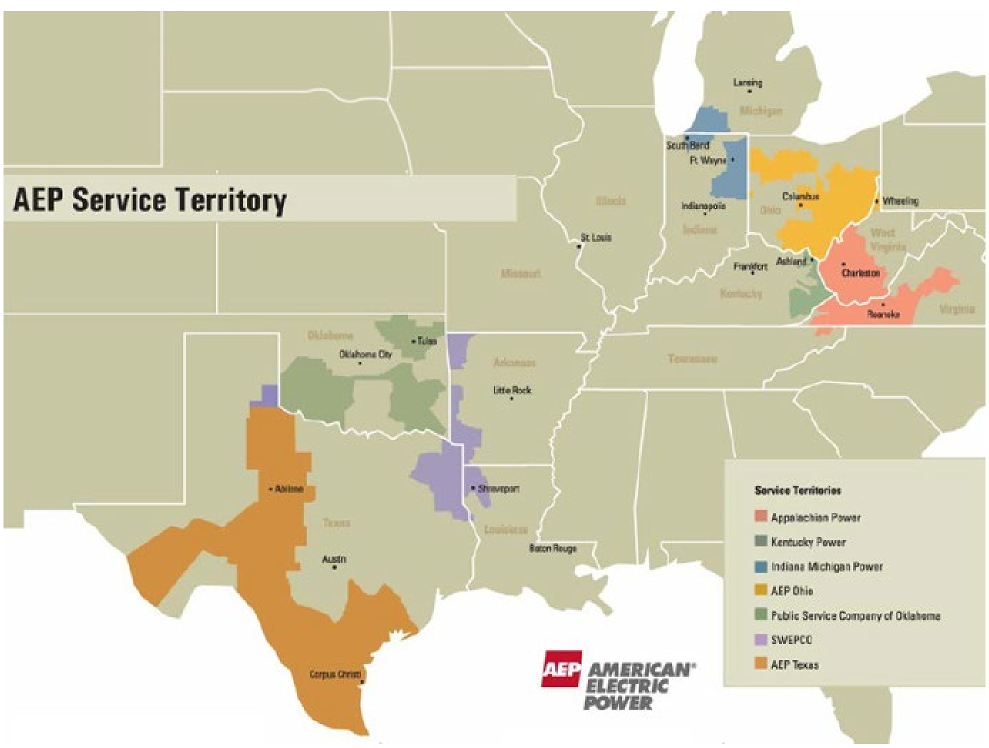
“This is a rapidly evolving situation that could lead to extended disruption of economic activity in our markets,” AEP said.

Deferred Maintenance

AEP and other Edison Electric Institute members have *pledged* to suspend utility disconnects during the crisis.

As of March 31, other major utilities including Consolidated Edison, Exelon, NextEra Energy, Entergy, CenterPoint Energy and Sempra Energy had not issued similar warnings to their stockholders.

DTE Energy *announced* March 23 that it is suspending all noncritical infrastructure and maintenance in response to the pandemic. “This move to keep employees home — in instances other than emergency response to customers — helps to ensure they do not add to the growing spread of the virus and further stress the health care system, equipment and services across the state,” it said.



AEP companies operate in 11 states. | *AEP*

“Right now, there’s definitely a lot of uncertainty regarding maintenance outages this spring,” said Maggie Cashman, a power market analyst for Genscape, during a webinar March 31. “The main concern that has been brought up … is the status of nuclear [refueling] given that they require a large number of contract workers from across the country.”

NB Power has decided to *delay* the refueling of its Point Lepreau Nuclear Generating Station in New Brunswick, which had been scheduled for April, because of the outbreak.

In the U.S., however, “nuclear outages have gone largely as planned,” Cashman said, noting the refueling of NextEra’s Seabrook plant in New Hampshire was expected to begin last week as scheduled. “Gas generation outages are much more likely to be postponed because they’re not critical and unnecessary for continued operation in the near term.”

The Nuclear Energy Institute *says* 32 nuclear plants in 21 states are scheduled for refueling outages this spring.

The Nuclear Regulatory Commission is allowing reductions in nonessential maintenance work, Cashman said. On March 28, the commission *said* it will allow temporary waivers of its rules limiting the number of plant operators who can stay at work.

Supply Chain

Duke Energy made an *8-K filing* March 27 on the pandemic saying it was “actively managing the materials, supplies and contract services for our generation, transmission, distribution and customer services functions” and has had “no issues of significance” in its supply chain. It said it would provide an update on the actual and potential business and financial effects of the pandemic when it announces first quarter 2020 financial results on May 12.

AEP said that while the company has instituted measures to protect its supply chain, global shortages will likely affect its maintenance and capital programs. AEP has enjoyed strong financial success lately. In February, it reported a total shareholder return of 30.5% in 2019, exceeding the 27.5% total return for the S&P 500 Electric Utilities Index. (See *Renewables Key to AEP’s Performance*.) However, the company’s stock has lost nearly 24% of its value since Feb. 18, when its share price hit a 52-week high of $104.97. Shares closed at $79.98 on March 31. ■

Company News

NextEra Said to be Eyeing Evergy as Acquisition Target

By Tom Kleckner

A publication that covers financial mergers and acquisitions said Friday that NextEra Energy is toying with the idea of acquiring Kansas City utility Evergy.

According to *M&A by Reorg*, recent activist pressure from Elliott Management, which manages funds that own an economic interest equivalent to approximately 10 million shares of Evergy's common stock, may make the company more willing to consider a sale.

NextEra has hired Citi to advise on the potential acquisition, and internal evaluations are at the preliminary stages, according to the report.

The publication said American Electric Power and Ameren are also said to be interested in Evergy.

NextEra declined to comment, following its policy to not respond to market rumors.

The Florida-based company failed in a 2016 effort to buy Texas utility Oncor. (See *Texas Commission Denies NextEra's Bid for Oncor*.)

AEP and Ameren also declined to comment. Ameren did note it is focused on executing its strategic plan, which is based on "strong organic growth" in its regulated businesses.

Evergy *announced* in early March that it had reached an agreement with Elliott to establish a new strategic review committee to explore ways to improve shareholder value. Elliott said at the time that Evergy is now "well positioned to significantly increase investment in critical electric infrastructure to benefit key stakeholders."

Evergy also agreed to add two new independent directors to its board, raising the number of directors to 17. The board's membership will be reduced to 13 by retirements before the May shareholders' meeting.

The two new directors, former Energy Future Holdings senior executive Paul Keglevic and NRG Energy CFO Kirk Andrews, will comprise half of the Strategic Review & Operations Committee, which will look at "potential strategic combination(s)" or a modified long-term standalone operating plan. It can retain its own independent consultants, advisers and counsel to facilitate its review and has an information-sharing agreement with Elliott.

"Elliott recognizes our commitment to serving the best interests of all Evergy stakeholders," Evergy CEO Terry Bassham said in the announcement. "We welcome these new, highly qualified directors and the significant and valuable experience they bring to this effort. The comprehensive strategic and operating review we are undertaking will help ensure that Evergy is directing capital to the greatest opportunities and continuing to consider all opportunities to enhance shareholder value."

Evergy, an SPP member, was created in 2018 by a merger between Kansas City Power and Light and Westar Energy. It serves 1.6 million customers in Kansas and Missouri. ■

NextEra Energy's corporate headquarters in Juno Beach, Fla. | © *RTO Insider*

Company Briefs

AMP Names New Sr. VP of Member Services and External Affairs

American Municipal Power (AMP) last week announced that Adam Ward had been promoted to senior vice president of member services and external affairs. In his new role, Ward will provide oversight to AMP's business and economic development efforts, sustainability initiatives, internal and external communications, government relations, technical services and member programs.

Ward joined AMP in February 2016 as assistant vice president of environmental affairs and policy, having previously served as assistant chief of the Air Pollution Control Division with the Ohio Environmental Protection Agency.

More: *AMP Partners*

CenterPoint Cutting Dividend, Spending

CenterPoint Energy last week announced it is cutting planned spending and slashing its dividend in response to a decrease in revenue.

CenterPoint's bottom line took a $155 million hit after Enable Midstream Partners, of which CenterPoint owns 54%, announced a 50% reduction in distribution on its common shares. As a result, CenterPoint said it would reduce the company's quarterly common stock dividend to 15 cents/share (down from 29 cents/share).

The company is also cutting roughly $300 million and $40 million from its capital spending and planned operation and maintenance spending, respectively.

More: *Houston Chronicle*

Murray Energy Pushed to Brink of Liquidation

Coal supplier Murray Energy last week said its business has taken such a hit from "historically bad" coal markets and the COVID-19 coronavirus pandemic that the bankrupt company is close to liquidation. The company said it is concerned it may breach covenants in its bankruptcy loan and lose access to the financing it needs to pay workers and suppliers.

To stay afloat, Murray on March 30 sought permission from a U.S. bankruptcy court to stop paying roughly $6 million a month in retiree medical costs and said that unless it can suspend those obligations, it "may be faced with no choice" but to liquidate and lay off roughly 4,900 employees.

More: *The Wall Street Journal*

OMEA Board Names New Executive Director

The Ohio Municipal Electric Association (OMEA) Board Executive Committee named Michael Beirne as its executive director during its March meeting.

Beirne joined American Municipal Power (AMP) and OMEA in 1998 and has advocated on behalf of Ohio's public power communities before state and federal policymakers.

Beirne replaced Jolene Thompson, who was named AMP president and CEO in April 2020.

More: *AMP Partners*

Southern Co. Warns COVID-19 Could Further Delay Plant Vogtle

Southern Co. last week warned investors that the COVID-19 coronavirus pandemic could disrupt its nuclear expansion of Plant Vogtle, a project that is already far behind schedule.

In its latest Securities and Exchange Commission filing, Southern said the pandemic and related government responses could reduce demand for energy and hurt the company's ability "to develop, construct and operate facilities and to access funds from financial institutions and capital markets." The company highlighted the potential for Vogtle delays, as Georgia Power has taken steps "designed to mitigate the risk of transmission at the construction site."

However, long before the coronavirus issue, the project was billions of dollars over budget and years behind its original schedule. Monthly electric bills of Georgia Power customers already include finance costs and company profits related to the project. Additional expenses are expected to be added to bills later.

More: *Atlanta Journal-Constitution*

SPP Extends Wind Penetration Mark to 72.4%

SPP set a new mark for wind penetration in the early-morning hours Thursday, when nearly three-fourths of its generation came from wind resources.

The RTO *tweeted* that at 1:56 a.m., wind resources served 72.4% of its 22.2 GW of load. That broke the previous record of 71.3%, set on Feb. 3. It has about 22.5 GW of installed wind capacity, much of it on the plains of Oklahoma and Kansas.

The grid operator is adjusting to changes in load patterns wrought by the COVID-19 pandemic. SPP said its morning peak is occurring "a bit later" but noted it has sufficient capacity to meet demand that is consistent with prior years.

More: *SPP*

Sungevity Lays off About 400 Workers

Sungevity last week eliminated 387 positions, according to a filing with California's Employment Development Department, which requires companies with more than 100 employees to report mass layoffs. The cuts were attributed to "business conditions and the COVID-19 outbreak."

Some staff were originally furloughed on March 20, with the company saying it was laying off "most of our workforce" effective March 27. Laid-off employees lost medical benefits on March 31. Because of a state of emergency initiated on March 4, the company was not mandated to give employees 60 days' notice.

The Solar Energy Industries Association trade group said the solar industry could lose up to half its jobs in certain sectors. The industry currently employs roughly 250,000 people in the U.S.

More: *GreenTech Media*

Sunrun Still at the Top of US Residential Solar Rankings

Wood Mackenzie's solar leaderboard data through Q4 2019 showed that Sunrun maintained its position as the largest residential solar installer in the country. The company edged out Vivint by 0.1% in overall market share for new capacity installations but registered a greater residential market lead over Vivint for 2019, at 9.2% of the market compared to Vivint's 8.3%.

Tesla remained in third in terms of residential market share every quarter last year while claiming a 5% market share in the final quarter of 2019.

More: *GreenTech Media*

Federal Briefs

Dems Seek Grid Funding in Next Stimulus Bill

House Democrats last week said they will push for massive infrastructure funding in the next economic stimulus bill in response to the COVID-19 pandemic, proposing $34.3 billion in grid security and modernization along with $4 billion over five years to fortify the grid against severe storms and other climate impacts. The most recent stimulus package did not address renewables.

President Trump reiterated his call for a $2 trillion infrastructure package but warned Democrats to stay clear of injecting the Green New Deal or similar climate change policies into the measure. Democrats are pushing climate-friendly infrastructure spending such as on resilient rail lines and the grid but are not proposing to include the Green New Deal in their package.

More: *Bloomberg Law*

DOE, EPA Staffers Test Positive for Coronavirus

EPA last week confirmed that, as of March 30, 11 employees had tested positive for coronavirus.

Internal emails showed EPA was notified on March 24 that an employee in Atlanta tested positive while a contractor in New York "may be infected." There have also been confirmed cases in EPA's Montana, Boston and D.C. headquarters offices. Additionally, another person in its Cincinnati office was "presumed positive" for the disease.

The Department of Energy had two employees at its headquarters in D.C. test positive last week as well to bring the department's total infected to three. Energy Secretary Dan Brouillette said neither employee had been in the building since March 19 nor had any physical contact with other staff since that time.

More: *E&E News*; *E&E News*

Gemini Solar Project Permit Delayed

The Bureau of Land Management last week delayed issuing a permit for the Gemini solar power project in Nevada, one of the nation's largest proposed solar farms, over concerns about its impact on a historic region.

A draft agreement between BLM and the Nevada State Historic Preservation Office said the $1 billion, 7,100-acre project would have a visual impact on a historic railroad camp on the Moapa River Indian Reservation. It would also have an impact on old travel and trade routes, including the Old Spanish National Historic Trail used by settlers in the 1830s to 1860s.

BLM spokeswoman Kirsten Cannon said the bureau can no longer give a time frame for a decision but is working "expeditiously" to finish the work. NV Energy said it still expects to complete the project on time in 2023.

More: *Reuters*

UN Delays Global Climate Talks amid Coronavirus Crisis

The U.N. Framework Convention on Climate Change meeting planned for November in Glasgow, Scotland, which had been viewed as a deadline for countries to release national plans to combat climate change, has been postponed as countries deal with the COVID-19 coronavirus pandemic.

Parties involved have not chosen a new date, though the U.N. pushed an intermediate meeting originally planned for June to October.

Most countries are behind in meeting the national commitments they made as part of the 2015 Paris climate agreement. The Glasgow conference was designed to ratchet up pressure on nations to reach those marks while setting more ambitious goals.

More: *POLITICO*

NRC Allowing Longer Shifts at Nuclear Plants

The Nuclear Regulatory Commission last week said it will allow nuclear power plants to have workers on for longer shifts in order to deal with staffing problems during the COVID-19 coronavirus pandemic.

Shift extensions would allow workers to be on the job for up to 86 hours a week. Currently, they are allowed to work up to 72 hours in a seven-day period, but as part of the waiver, workers could be assigned to 12-hour shifts for as many as 14 days in a row.

NRC Director of Reactor Regulation Ho Nieh said federal inspectors would monitor plants so that no plant works its employees to the point of bleariness and that regulators can approve or revoke expanded shifts on a plant-by-plant basis.

More: *The Associated Press*

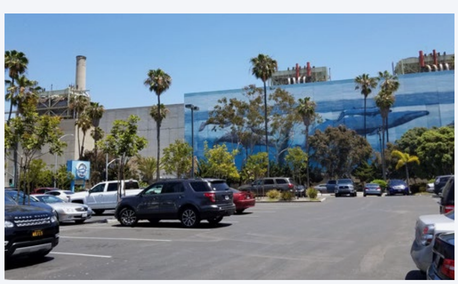
State Briefs

CALIFORNIA

Coastal Gas Plant to Shut Down by 2023

AES last week said it has closed a sale on 51 acres of land to real estate developer Leo Pustilnikov that will require the company to stop operating the Redondo Beach gas-burning plant by 2023. No financials of the deal were disclosed.

AES was supposed to cease operations



by Dec. 31 under a state policy requiring coastal energy generators to either shut down or stop using ocean water for cooling.

However, the Public Utilities Commission proposed to extend the closure deadline last November out of fear that Southern California would not have enough power on hot summer evenings.

If AES can keep the plant operating for three more years, the company will transfer $14 million to Pustilnikov for environmental cleanup. Pustilnikov has also agreed to preserve half of the site as public parkland.

More: *Los Angeles Times*

LOUISIANA

Lake Charles Power Station Becomes Operational

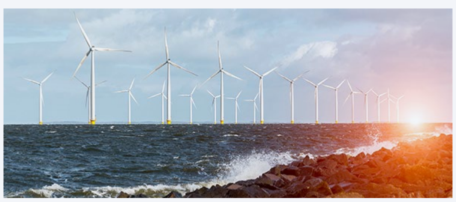
Entergy Louisiana announced last week that its $872 million Lake Charles Power Station began commercially operating on March 28.

The 980-MW station uses combined cycle gas turbine units that emit roughly 40% less carbon dioxide than Entergy's older natural gas-powered units, according to the company. Because of its high efficiency, the company projected that customers will save between $1.3 billion and $2 billion over the anticipated 30-year life of the plant.

More: *Entergy*

MASSACHUSETTS

Brayton Center Open for Business



The Brayton Point Commerce Center last week announced it is open for business for the offshore wind industry after the Contractor EnviroAnalytics Group completed 18 months of work to upgrade heavy-lift port operations and receive deep-draft vessels. Brayton Point was previously the location of a coal-fired power plant.

"Our crews have safely deconstructed and removed 1.5 million square feet of former power plant infrastructure. We now have a blank canvas to create a platform for new development as the site matures into Brayton Point Commerce Center," EnviroAnalytics President Russ Becker said.

Brayton Point has received a total of nine vessel calls, including offshore wind research boats.

More: *reNews*

MICHIGAN

Ann Arbor Unveils $1B Plan to Go Carbon-neutral

Ann Arbor last week outlined more than 40 actions it hopes to take to achieve carbon-neutrality by 2030. The city estimates implementing the measures would cost more than $1 billion over the next 10 years.

Some of the strategies of the "A2Zero" plan include reducing vehicle miles traveled by at least 50%; switching appliances and vehicles from gasoline, diesel, propane and natural gas to electric; and improving energy efficiency of homes, businesses, schools, places of worship, recreational sites and government facilities. The plan also calls for a community solar program, with a goal of residents buying 11 MW worth of solar projects by 2030, with $205,000 in costs to the city over 10 years to administer the program.

More: *MLive*

MONTANA

Bullock Suspends Utility Shutoffs

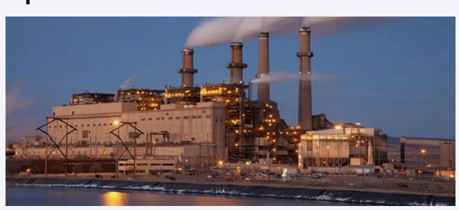
Gov. **Steve Bullock** last week banned utilities and companies from shutting off electric, gas, sewer, water, phone and internet services or charging late fees. However, the order does not relieve tenants or homeowners of their payment obligations.

NorthWestern Energy, the state's largest utility, has already undertaken the same initiatives.

More: *Independent Record*

NEW MEXICO

PRC Approves PNM Ending San Juan Operations



The Public Regulation Commission last week unanimously approved the Public Service Company of New Mexico's (PNM) application to end its operations of the San Juan Generating Station.

The deadline for the PRC to make a ruling on the abandonment case was April 1 based on guidelines outlined in the Energy Transition Act. Had it not made a ruling, the application PNM filed on July 1 would have been deemed approved.

The PRC also approved a financing order that allows PNM to issue low-interest energy transition bonds. The bonds include $283 million of refinancing of past investments into the San Juan Generating Station as well as $19.2 million for the decommissioning.

More: *Farmington Daily Times*

NEW YORK

Last Coal-burning Plant in State Closes

Somerset Operating Co. last week officially retired its coal-burning power plant on the shore of Lake Ontario in Niagara County, meaning there are no coal plants left operating in the state.

The 675-MW plant, which was opened in 1983 by New York State Electric and Gas, last generated electricity on March 13 when it burned its last bit of coal. The process ended at 12:02 a.m. on March 14. The plant sat idle more than it ran in recent years, and it has been at least five years since the plant operated without interruption for as long as a month.

The shutdown also means 52 people will be laid off.

More: *The Buffalo News*

RHODE ISLAND

PUC OKs Plan to Buy Power from Ct. Solar Project

The Public Utilities Commission last week unanimously approved a 20-year agreement that will pay D.E. Shaw Renewable Investments 5.3 cents/kWh for energy and environmental benefits from the future 50-MW Gravel Pit Solar project in Connecticut.

The deal is the first time National Grid has joined with its much smaller counterparts, the Pascoag Utility District and the Block Island Utility District, to buy renewable energy.

More: *Providence Journal*